INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • Fax (317) 233-6647 • www.idem.IN.gov

Mike Braun
Governor

Clint Woods
Commissioner

NOTICE OF PUBLIC HEARING

Preliminary Findings Regarding a PSD/Significant Modification to a Part 70 Operating Permit

for Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station in Jasper County

PSD/Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No.: 073-49651-00008

The Indiana Department of Environmental Management (IDEM) has received an application from Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station, located at 2723 East 1500 North, Wheatfield, Indiana 46392, for a PSD/significant modification. IDEM's Office of Air Quality (OAQ) issues this type of permit to regulate the operation of existing sources and modifications at existing sources that release air pollutants.

The Office of Air Quality (OAQ) had a notice posted on IDEM's website (https://www.in.gov/idem/public-notices/) stating that the draft PSD/significant modification for Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station had been proposed for this operation and provided information on how the public could review the proposed permit and other documentation. Due to a written public hearing request and several comments received by IDEM from interested parties, a virtual public hearing will be held on June 3, 2026 to discuss air permitting for Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station.

A copy of the permit application and IDEM's preliminary findings have been sent to:

Jasper County Public Library Wheatfield Public Library
350 S. Bierma Street
Wheatfield, IN 46392

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

A copy of the application and preliminary findings is also available via IDEM's Virtual File Cabinet (VFC) located at https://www.in.gov/idem/legal/public-records/virtual-file-cabinet/. Once you have accessed VFC, you will then have the option to search for source related documents using a variety of criteria. To find documents related to this air permit, click on "Advanced Search", specify "OAQ" in the Program search field, specify the five-digit permit number "49651" or the the five-digit source modification number "49556" in the Permit # search field, then click the Search button at the top or bottom of the webpage.

You are invited to attend a virtual public hearing regarding the Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station air permitting preliminary findings. The Indiana Department of Environmental Management (IDEM) will hold a public hearing to allow for testimony regarding the draft PSD/significant modification. **IDEM, OAQ will not provide responses to questions or comments made during the hearing.** IDEM will review all comments and questions received during the hearing, and submitted as part of the public comment period, and after careful consideration and further analysis, if necessary, provide detailed responses in writing as part of the final decision.

IDEM, OAQ will hold this virtual public hearing via Microsoft Teams at the following time and internet address:

June 3, 2026, starting at 6:00 PM, Central Daylight Time at https://on.in.gov/nipsco-hearing

Meeting ID: 298 392 992 529 607
Passcode: pT3PS7u8

The hearing will end at 9:00 PM, Central Daylight Time, or when all testimony has been provided, whichever is earlier.

Attendees may also participate in the public hearing by telephone using the following telephone number:

Dial-in by phone
+1 317-552-1674,,715999506# United States, Indianapolis, IN
Phone conference ID: 715 999 506#

1. The public hearing will be conducted using the Microsoft Teams software application. Participants will be able to join the hearing without downloading the Teams application.
2. Participants, especially those wishing to speak, should also add their name, when prompted, while joining or signing into the meeting.
3. When participants join the hearing, they will be placed in a virtual waiting room until the public hearing begins. Anyone wishing to provide oral comments during the hearing should complete the Speaker Form using the instructions available in the waiting room. The form link and waiting room will be available beginning about one hour before the scheduled start of the hearing.
4. It is recommended that anyone speaking during the hearing use headphones with a microphone.
5. The chat feature will only be used for participants who have procedural questions or need technical assistance during the hearing. Chat messages will not become part of the record and will not be considered comments on the draft permit documents.
6. Participants with documents, presentations or other materials will not be able to submit them during the meeting. These materials should be submitted to IDEM, OAQ during the public comment period pursuant to the instructions below on how to submit comments and supporting documents.

If you need reasonable accommodations to participate in this event, please contact IDEM's Americans with Disabilities Act coordinator at:

Indiana Department of Environmental Management
Attn: ADA Coordinator
402 W Washington St - Room E034
Indianapolis, IN 46204
317-233-4088
ESE@idem.IN.gov

Please provide a minimum of 24 hours notice if possible. Speech and hearing impaired callers may contact the agency via the Indiana Relay Service at 1-800-743-3333.

How can you participate in this process?
Written comments and supporting documentation can be submitted to IDEM before the end of the public notice period. The public notice period will end on Monday, June 8, 2026. All comments will be considered by IDEM when we make a decision to issue or deny the permit. Comments that are most likely to affect final permit decisions are those based on the rules and laws governing this permitting process (326 IAC 2), air quality issues, and technical issues. IDEM does not have legal authority to regulate zoning, odor or noise. For such issues, please contact your local officials. If you do not want to comment, but would like to be added to IDEM's mailing list to receive notice of future action related to this permit application, please contact IDEM. Please refer to permit number 073-49651-00008 and 073-49556-00008 in all correspondence.

To Contact IDEM:

Hachem Ismaili Alaoui
IDEM, Office of Air Quality
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251
(800) 451-6027, ask for Hachem Ismaili Alaoui or (317) 232-2827
Or dial directly: (317) 232-2827
Fax: (317) 232-6749 attn: Hachem Ismaili Alaoui
E-mail: hialaoui@idem.IN.gov

In order to notify you of our final decision regarding this permitting action, your U.S. mailing address must be submitted with all comments.

What will happen after IDEM makes a decision?
Following the end of the public comment period, IDEM will issue a Notice of Decision stating whether the permit has been issued or denied. If the permit is issued, it may be different than the draft permit because of comments that were received during the public comment period. If comments are received during the public notice period, the final decision will include a document that summarizes the comments and IDEM's response to those comments. If you have submitted comments or have asked to be added to the mailing list, you will receive a Notice of the Decision. The notice will provide details on how you may appeal IDEM's decision, if you disagree with that decision. The final decision will also be available on the Internet at the addresses indicated above and will also be sent to the local library indicated above.

If you have any questions, please contact Hachem Ismaili Alaoui of my staff at the above address.

Ghassan Shalabi, Section Chief
Permits Branch
Office of Air Quality

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: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

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Mike Braun
Governor

Clint Woods
Commissioner

NOTICE OF 30-DAY PERIOD FOR PUBLIC COMMENT

Preliminary Findings Regarding a
PSD/Significant Modification to a
Part 70 Operating Permit

for Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station in Jasper County

PSD/Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No.: 073-49651-00008

The Indiana Department of Environmental Management (IDEM) has received an application from Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station, located at 2723 East 1500 North, Wheatfield, Indiana 46392, for a PSD/significant modification of its Part 70 Operating Permit issued on November 13, 2023. If approved by IDEM's Office of Air Quality (OAQ), this proposed modification would allow Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station to make certain changes at its existing source. Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station has applied to construct operate four (4) combined cycle combustion turbines, two (2) auxiliary boilers, two (2) mechanical draft cooling towers, one (1) natural gas-fired dew point heater, six (6) lube oil tanks with demister vents, two (2) diesel-fired emergency generators, two (2) diesel-fired fire pumps, and one (1) diesel storage tank. In addition, the source applied to equip the existing combustion turbines with oxidation catalysts and to include emissions from circuit breakers and piping fugitives.

The applicant intends to construct and operate new equipment that will emit air pollutants; therefore, the permit contains new or different permit conditions. In addition, some conditions from previously issued permits/approvals have been corrected, changed, or removed. These corrections, changes, and removals may include Title I changes (e.g., changes that add or modify synthetic minor emission limits). IDEM has reviewed this application and has developed preliminary findings, consisting of a draft permit and several supporting documents, which would allow the applicant to make this change.

A copy of the permit application and IDEM's preliminary findings have been sent to:

Jasper County Public Library Wheatfield Public Library
350 S. Bierma Street
Wheatfield, IN 46392

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

A copy of the application and preliminary findings is also available via IDEM's Virtual File Cabinet (VFC) located at https://www.in.gov/idem/legal/public-records/virtual-file-cabinet/. Once you have accessed VFC, you will then have the option to search for source related documents using a variety of criteria. To find documents related to this air permit, click on "Advanced Search", specify "OAQ" in the Program search field, specify the five-digit permit number "49651" or the five-digit source modification number "49556", in the Permit # search field, then click the Search button at the top or bottom of the webpage.

How can you participate in this process?

This notice is posted on IDEM's website (https://www.in.gov/idem/public-notices/). The date that this notice is posted on IDEM's website marks the beginning of the public comment period. IDEM will be conducting a virtual public hearing on June 3, 2026. IDEM will post a separate announcement of the date, time, and location of the public hearing on IDEM's website (https://www.in.gov/idem/public-notices/). The public comment period

will end on Monday, June 8, 2026. At a hearing, you will have an opportunity to submit written comments and make verbal comments. All comments must be postmarked, faxed, emailed, or delivered in person by Monday, June 8, 2026.

Comments and supporting documentation should be sent in writing to IDEM at the address below. If you comment via e-mail, please include your full U.S. mailing address so that you can be added to IDEM's mailing list to receive notice of future action related to this permit. If you do not want to comment at this time, but would like to receive notice of future action related to this permit application, please contact IDEM at the address below. Please refer to permit number SPM 073-49651-00008 and SSM 073-49556-00008 in all correspondence.

Comments should be sent to:

Hachem Ismaili Alaoui
IDEM, Office of Air Quality
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251
(800) 451-6027, ask for Hachem Ismaili Alaoui or (317) 232-2827
Or dial directly: (317) 232-2827
Fax: (317) 232-6749 attn: Hachem Ismaili Alaoui
E-mail: hialaoui@idem.IN.gov

In order to notify you of our final decision regarding this permitting action, your U.S. mailing address must be submitted with all comments.

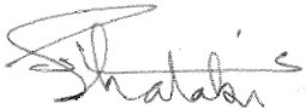
All comments will be considered by IDEM when we make a decision to issue or deny the permit. Comments that are most likely to affect final permit decisions are those based on the rules and laws governing this permitting process (326 IAC 2), air quality issues, and technical issues. IDEM does not have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

For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Air Permits page on the Internet at: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

What will happen after IDEM makes a decision?

Following the end of the public comment period, IDEM will issue a Notice of Decision stating whether the permit has been issued or denied. If the permit is issued, it may be different than the draft permit because of comments that were received during the public comment period. If comments are received during the public notice period, the final decision will include a document that summarizes the comments and IDEM's response to those comments. If you have submitted comments or have asked to be added to the mailing list, you will receive a Notice of the Decision. The notice will provide details on how you may appeal IDEM's decision, if you disagree with that decision. The final decision will also be available on the Internet at the addresses indicated above and will also be sent to the local library indicated above.

If you have any questions, please contact Hachem Ismaili Alaoui of my staff at the above address.



Ghassan Shalabi, Section Chief
Permits Branch
Office of Air Quality

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Governor

Clint Woods
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Mr. Keith Weber
Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station
801 E 86th Avenue
Merrillville, IN 46410

Re: 073-49556-00008
PSD/Significant Source Modification

Dear Mr. Weber:

Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station was issued Part 70 Operating Permit Renewal No. T073-45762-00008 on November 13, 2023 for a stationary electric utility generating station located at 2723 East 1500 North, Wheatfield, Indiana 46392. An application to modify the source was received on September 5, 2025. Pursuant to the provisions of 326 IAC 2-7-10.5, a PSD/Significant Source Modification is hereby approved as described in the attached Technical Support Document.

Pursuant to 326 IAC 2-7-10.5, the following emission units are approved for construction at the source:

(a) Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a rated maximum capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a rated maximum of 987 MMBtu per hour, using dry low-NOx combustors and voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(b) Two (2) natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, approved in 2026 for construction, each with a rated maximum capacity of 115 MMBtu per hour, using low NOx burners, and exhausting to stacks SAUX1 and SAUX2.

[Under 40 CFR 60, Subpart Db, these units are affected facilities]
[Under 40 CFR 63, Subpart DDDDD, these units are affected sources]

(c) One (1) natural gas-fired dew point heater, identified as DPH1, approved in 2026 for construction, with a rated maximum capacity of 28 MMBtu per hour, and exhausting to stack SDPH1.

[Under 40 CFR 60, Subpart Dc, this is an affected facility]
[Under 40 CFR 63, Subpart DDDDD, this is an affected source]

(d) Two (2) mechanical draft cooling towers, identified as CTH1 and CTH2, approved in 2026 for

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construction, each with a rated maximum circulation of 280,000 gallons of water minute, TDS of 2,000 ppm, and total drift loss of 0.001%.

(e) Two (2) 2,500 kW diesel-fired certified emergency generators, identified as EDGCC1 and EDGCC2, approved in 2026 for construction, each with a rated maximum capacity of 3,353 hp, and exhausting to stacks SEDGCC1 and SEDGCC2.

[Under 40 CFR 60, Subpart IIII, these units are affected facilities]
[Under 40 CFR 63, Subpart ZZZZ, these units are affected sources]

(f) Two (2) 244 kW diesel-fired certified emergency fire pumps, identified as FPCC1 and FPCC2, approved in 2026 for construction, each with a rated maximum capacity of 327 hp, and exhausting to stacks SFPCC1 and SFPCC2.

[Under 40 CFR 60, Subpart IIII, these units are affected facilities]
[Under 40 CFR 63, Subpart ZZZZ, these units are affected sources]

(g) One (1) diesel storage tank, identified as TKCC1, approved in 2026 for construction, with a design storage capacity of 5,000 gallons and maximum throughput of 130,000 gallons per year, and exhausting outdoors.

(h) Six (6) lube oil demister vents, identified as LOV21A, LOV21B, LOV22A, LOV22B, LOV21S, and LOV22S, approved in 2026 for construction, each with a vent flow rate of 500 cfm.

(i) High Voltage Electric Switchgear Containing Sulfur Hexafluoride (SF6), identified as CCCT - Circuit Breakers, approved in 2026 for construction.

(j) Natural gas piping components, identified as CCCT - Piping Systems, approved in 2026 for construction, including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections.

(k) High Voltage Electric Switchgear Containing Sulfur Hexafluoride (SF6), identified as Peaker - Circuit Breakers.

(l) Natural gas piping components, identified as Peaker - Piping Systems, including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections.

The following construction conditions are applicable to the proposed modification:

General Construction Conditions

1. The data and information supplied with the application shall be considered part of this source modification approval. Prior to any proposed change in construction which may affect the potential to emit (PTE) of the proposed project, the change must be approved by the Office of Air Quality (OAQ).

2. This approval to construct does not relieve the Permittee of the responsibility to comply with the provisions of the Indiana Environmental Management Law (IC 13-11 through 13-20; 13-22 through 13-25; and 13-30), the Air Pollution Control Law (IC 13-17) and the rules promulgated thereunder, as well as other applicable local, state, and federal requirements.

Effective Date of the Permit

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

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Commenced Construction

4. Pursuant to 326 IAC 2-1.1-9 and 326 IAC 2-7-10.5(j), the Commissioner may revoke this approval if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is suspended for a continuous period of one (1) year or more.

5. All requirements and conditions of this construction approval shall remain in effect unless modified in a manner consistent with procedures established pursuant to 326 IAC 2.

Approval to Construct

6. Pursuant to 326 IAC 2-7-10.5(h)(2), this Significant Source Modification authorizes the construction of the new emission unit(s), when the Significant Source Modification has been issued.

   Pursuant to 326 IAC 2-7-10.5(m), the emission units constructed under this approval shall not be placed into operation prior to revision of the source's Part 70 Operating Permit to incorporate the required operation conditions.

   Pursuant to 326 IAC 2-7-12, operation of the new emission unit(s) is not approved until the Significant Permit Modification has been issued. Operating conditions shall be incorporated into the Part 70 Operating Permit as a Significant Permit Modification in accordance with 326 IAC 2-7-10.5(m)(2) and 326 IAC 2-7-12 (Permit Modification).

A copy of the permit is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/. A copy of the application and permit is also available via IDEM's Virtual File Cabinet (VFC) located at https://www.in.gov/idem/legal/public-records/virtual-file-cabinet/. Once you have accessed VFC, you will then have the option to search for source related documents using a variety of criteria. To find documents related to this air permit, click on "Advanced Search", specify "OAQ" in the Program search field, specify the five-digit permit number "49556" in the Permit # search field, then click the Search button at the top or bottom of the webpage.

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: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

This decision is subject to the Indiana Administrative Orders and Procedures Act - IC 4-21.5-3-5.

If you have any questions regarding this matter, please contact Hachem Ismaili Alaoui, Indiana Department Environmental Management, Office of Air Quality, Permits Branch, Indiana Government Center North, 100 North Senate Avenue, Room 13W, Indianapolis, Indiana 46204-2251, or by telephone at (317) 232-2827 or (800) 451-6027, and ask for Hachem Ismaili Alaoui or (317) 232-2827.

Sincerely,

Ghassan Shalabi, Section Chief
Permits Branch
Office of Air Quality

Attachments: PSD/Significant Source Modification and Technical Support Document

cc: File - Jasper County
Jasper County Health Department
U.S. EPA, Region 5
Compliance and Enforcement Branch

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

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Commissioner

PSD/Significant Source Modification to a Part 70 Source

OFFICE OF AIR QUALITY

Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station

2723 East 1500 North
Wheatfield, Indiana 46392

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

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

PSD/Significant Source Modification No.: 073-49556-00008 Master Agency Interest ID.: 11840	
Issued by: Jenny Acker, Branch Chief Permits Branch Office of Air Quality	Issuance Date:

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SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 through A.4 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(20)]

The Permittee owns and operates a stationary electric utility generating station.

Source Address:	2723 East 1500 North, Wheatfield, Indiana 46392
General Source Phone Number:	219-956-5385
SIC Code:	4911
County Location:	Jasper
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

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

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

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source]

(b) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility]

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

(c) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, and exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

[Under 40 CFR Part 60, Subpart GG these units are affected facilities]

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a rated maximum heat input capacity of 519 MMBtu per hour, each using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR 60, Subpart KKKK these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa these units are intermediate load affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a rated maximum heat input capacity of 2,416 MMBtu per hour, using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR 60, Subpart KKKK this unit is an affected facility]
[Under 40 CFR 60, Subpart TTTTa this unit is an intermediate load affected facility]
[Under 40 CFR 63, Subpart YYYY, this unit is an affected source]

(f) Fuel storage and handling systems for Unit 17 and 18 boilers, constructed in 1980.

(1) Rail car unloading of coal, with a multi-compartment baghouse for PM control and enclosure for ancillary dust control.

(2) Truck unloading of petroleum coke (petcoke).

(3) Coal pile unloading, coal storage pile(s), petcoke pile unloading, petcoke storage pile(s), material handling equipment, and conveyors.

(4) Transfer House with an estimated throughput of 4,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a multi-compartment baghouse for PM control. To produce petcoke blends, coal and petcoke are combined in rotary plow during transfer to conveyor.

(5) Crusher House with a designated capacity of 3,000 tons per hour, with enclosed transfer points within an enclosure for dust control, with a multi-compartment baghouse for PM control.

(6) Transfer House to tripper with an estimated throughput of 3,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a baghouse, identified as TFDC-XFR, for PM control, constructed in 2015.

(7) Two (2) tripper conveyors with an estimated combined throughput of 3,000 tons per hour with enclosure for ancillary dust control, with a baghouse, identified as TFDC-18 for PM control, constructed in 2015.

(8) Twelve (12) Fuel Silos (bunkers) with enclosure for dust control, with two (2) baghouses, identified as TFDC-17 and TFDC-18, for PM control, constructed in 2015.

[Under 40 CFR Part 60, Subpart Y this unit is an affected facility.]

(g) Material handling for the flue gas desulfurization systems for Unit 17 and 18 boilers, constructed in 1980, including the following:

(1) One (1) limestone slurry preparation system with a maximum hourly throughput rate of 38,941 pounds of limestone per hour, constructed in 1980.

(2) Three (3) ground limestone pneumatic truck unloading systems connected to Unit 17 and Unit 18 limestone silos, constructed in 1980, with baghouses for PM control.

(3) One (1) gypsum conveying system, with a maximum design throughput of 150 tons per hour, constructed in 1980. All gypsum is handled wet.

(4) One (1) radial stacker, identified as 7MX04G-RS, shared among Units 17 and 18, with rated capacity of 220 tons/hour, constructed in 2013.

(5) One (1) radial stacker, identified as 8MX04G-RS, shared among Units 17 and 18, with rated capacity of 220 tons/hour, constructed in 2016.

(h) Dry fly ash handling and disposal.

(1) Pneumatic fly ash conveyance to storage silos, with a design capacity of 63 tons per hour of fly ash from each of Units 17 and 18.

(2) Fly ash storage silos for Units 17, and 18, with cyclone separators, filter/separators**,** silo collector bag filters, and silo bin vent bag filters. Each silo has wet and dry unloaders, each with a design unloading capacity of 300+ tons per hour, with particulate emissions controlled by the use of a telescoping chute, with a vacuum system and a bin vent filter when the ash is being loaded dry, and controlled by the use of water spray mixed with the ash when the ash is being loaded wet.

(3) Transportation by truck via in-plant haul roads and onsite disposal area.

(i) Wet process bottom ash handling, with sluicing lines conveying ash to storage ponds in the Waste Disposal Area.

(j) Ponded bottom ash handling/removal operations.

(k) Material handling for the flue gas desulfurization systems for Unit 17 and Unit 18 boilers, including the following:

(1) Transportation of limestone by truck on paved road.

(2) Three (3) storage silos originally used for dual-alkali FGD system with baghouses for PM control.

(3) Two (2) upgraded incline belt conveyors, constructed in 2013, and shared among Units 17 and 18 for transfer of dewatered gypsum to the radial stackers.

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(4) Transportation of off-specification gypsum by truck on unpaved roads.

(l) One (1) natural gas-fired temporary boiler, constructed in 2020, with a rated maximum capacity of less than or equal to 99.9 MMBtu per hour, and exhausting outdoors.

(m) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a rated maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

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

(n) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a rated maximum capacity of 327 horsepower, and exhausting to stack FP1.

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

(o) Four (4) natural gas-fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a rated maximum capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a rated maximum heat input of 987 MMBtu per hour, using dry low-NOx combustors and voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(p) Two (2) natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, approved in 2026 for construction, each with a rated maximum capacity of 115 MMBtu per hour, using low NOx burners, and exhausting to stacks SAUX1 and SAUX2.

[Under 40 CFR 60, Subpart Db, these units are affected facilities]
[Under 40 CFR 63, Subpart DDDDD, these units are affected sources]

(q) One (1) natural gas-fired dew point heater, identified as DPH1, approved in 2026 for construction, with a rated maximum capacity of 28 MMBtu per hour, and exhausting to stack SDPH1.

[Under 40 CFR 60, Subpart Dc, this unit is an affected facility]
[Under 40 CFR 63, Subpart DDDDD, this unit is an affected source]

(r) Two (2) 2,500 kW diesel-fired certified emergency generators, identified as EDGCC1 and

EDGCC2, approved in 2026 for construction, each with a rated maximum capacity of 3,353 hp, and exhausting to stacks SEDGCC1 and SEDGCC2.

[Under 40 CFR Part 60, Subpart IIII, these units are affected facilities]
[Under 40 CFR Part 63, Subpart ZZZZ, these units are affected sources]

(s) Two (2) 244 kW diesel-fired certified emergency fire pumps, identified as FPCC1 and FPCC2, approved in 2026 for construction, each with a rated maximum capacity of 327 hp, and exhausting to stacks SFPCC1 and SFPCC2.

[Under 40 CFR Part 60, Subpart IIII, these units are affected facilities]
[Under 40 CFR Part 63, Subpart ZZZZ, these units are affected sources]

A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(19)] [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(19):

(a) Conveyors as follows:

(1) Covered conveyor for coal or coke conveying of less than or equal to 360 tons per day.

(2) Covered conveyors for limestone conveying of less than or equal to 7,200 tons per day for sources other than mineral processing plants constructed after August 31, 1983.

(3) Uncovered coal conveying of less than or equal to 120 tons per day; and

(4) Underground conveyors.

(b) Coal bunker and coal scale exhausts and associated dust collector vents.

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

(d) Any of the following structural steel and bridge fabrication activities:

(1) Cutting 200,000 linear feet or less of one inch (1") plate or equivalent.

(2) Using 80 tons or less of welding consumables.

(e) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system, constructed 2016.

[Under 40 CFR 60, Subpart IIII, this facility is considered a new affected facility]
[Under 40 CFR 63, Subpart ZZZZ, this facility is considered a new affected source]

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

(g) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(1) Coal pile wind erosion.

(2) Wet handling of FGD sludge material collected from the FGD building sumps, sluiced to the Material Storage Runoff Pond. FGD material dredged from pond inlet area is dewatered on the pond bank with trucks conveying dewatered material to onsite landfill.

(3) Shot blasters.

(4) Gypsum stockpiles.

(5) Cold Cleaner degreasing operations

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

(h) Two (2) on-site storage piles, each with approximate storage area of 3,440 square feet.

(i) Truck transport of gypsum to the stockpiles and conveyor on paved and unpaved roads.

(j) Two (2) mechanical draft cooling towers, identified as CTH1 and CTH2, approved in 2026 for construction, each with a rated maximum circulation of 280,000 gallons of water per minute, TDS of 2,000 ppm, and total drift loss of 0.0005%.

(k) One (1) diesel storage tank, identified as TKCC1, approved in 2026 for construction, with a design storage capacity of 5,000 gallons and rated throughput of 130,000 gallons per year, and exhausting outdoors.

(l) Six (6) lube oil demister vents, identified as LOV21A, LOV21B, LOV22A, LOV22B, LOV21S, and LOV22S, approved in 2026 for construction, each with a vent flow rate of 500 cfm.

(m) High Voltage Electric Switchgear Containing Sulfur Hexafluoride (SF6), identified as CCCT - Circuit Breakers, approved in 2026 for construction.

(n) High Voltage Electric Switchgear Containing Sulfur Hexafluoride (SF6), identified as Peaker - Circuit Breakers.

(o) Natural gas piping components, identified as CCCT - Piping Systems, approved in 2026 for construction, including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections.

(p) Natural gas piping components, identified as Peaker - Piping Systems, including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections.

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

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

(a) It is a major source, as defined in 326 IAC 2-7-1(20);

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(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).

(c) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3).

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SECTION B GENERAL CONDITIONS

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

(a) 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) Notwithstanding B.1(a), the terms located in paragraphs of the Decree that are incorporated by reference into this permit in accordance with Section F and Attachment A shall have the definition, and only the definition, assigned to such terms in the Decree and are limited to Section F and Attachment A.

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, T 073-45762-00008, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

(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.

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(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(33), 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(33).

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
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region 5
Air and Radiation Division, Air Enforcement Branch - Indiana (AE-17J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

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

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

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

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

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(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(33).

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
Indiana Government Center North
100 North Senate Avenue, Room 13W
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(33).

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(33).

(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 Reserved

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 T 073-45762-00008 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

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

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

(b) Provided that all terms and conditions are accurately reflected in this permit, all previous registrations and permits are superseded by this Part 70 operating permit, except for permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control)

B.14 Reserved

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(33).

(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(19) and 326 IAC 2-7-1(39). 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(33).

Request for renewal shall be submitted to:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
Indiana Government Center North
100 North Senate Avenue, Room 13W
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] [40 CFR 72]

(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) Pursuant to 326 IAC 2-7-11(b) and 326 IAC 2-7-12(a), administrative Part 70 operating permit amendments and permit modifications for purposes of the acid rain portion of a Part 70 permit shall be governed by regulations promulgated under Title IV of the Clean Air Act. [40 CFR 72]

(c) 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
Indiana Government Center North
100 North Senate Avenue, Room 13W
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(33).

(d) 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
Indiana Government Center North
100 North Senate Avenue, Room 13W
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(35)) 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(33).

(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.

(f) This condition does not apply to emission trades of SO_2 or NO_X under 326 IAC 21.

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
Indiana Government Center North
100 North Senate Avenue, Room 13W
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(33).

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

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

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

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

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

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

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

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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 Reserved

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

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

C.8 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

(a) Notification requirements apply to each owner or operator. If the combined amount of regulated asbestos containing material (RACM) to be stripped, removed or disturbed is at

least 260 linear feet on pipes or 160 square feet on other facility components, or at least thirty-five (35) cubic feet on all facility components, then the notification requirements of 326 IAC 14-10-3 are mandatory. All demolition projects require notification whether or not asbestos is present.

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

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

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

(A) Asbestos removal or demolition start date;

(B) Removal or demolition contractor; or

(C) Waste disposal site.

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

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

All required notifications shall be submitted to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
Indiana Government Center North
100 North Senate Avenue, Room 13W
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(33).

(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.9 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
Indiana Government Center North
100 North Senate Avenue, Room 13W
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(33).

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. In the event that a previously scheduled test must be canceled and rescheduled, the Permittee of the source or emissions unit shall notify the department no less than fourteen (14) days in advance of the rescheduled test date. Tests rescheduled for less than fourteen (14) days after notifying the department of the rescheduled test date must be approved by the department. 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(33).

(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.10 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.11 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
Indiana Government Center North
100 North Senate Avenue, Room 13W
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(33).

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

(c) 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.12 Reserved

C.13 Reserved

C.14 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.15 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.16 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.17 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.

(II)

(a) CAM *Response to excursions or exceedances.*

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

(2) Determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

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

(c) Based on the results of a determination made under paragraph (II)(a)(2) of this condition, the EPA or IDEM, OAQ may require the Permittee to develop and implement a Quality Improvement Plan (QIP). The Permittee shall develop and implement a QIP if notified to in writing by the EPA or IDEM, OAQ.

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

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

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

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

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

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

(h) *CAM recordkeeping requirements.*

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

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

C.18 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(33).

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

C.19 Malfunctions Report [326 IAC 1-6-2]

Pursuant to 326 IAC 1-6-2 (Records; Notice of Malfunction):

(a) A record of all malfunctions, startups or shutdowns of any emission unit or emission control equipment, that result in violations of applicable air pollution control regulations or applicable emission limitations must be kept and retained for a period of three (3) years

and shall be made available to the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ) or appointed representative upon request.

(b) When a malfunction of any emission unit or emission control equipment: 1) results in violations of applicable air pollution control regulations or applicable emissions limitations and 2) lasts more than one (1) hour, the condition shall be reported to OAQ, using the Malfunction Report Forms (2 pages) or its equivalent. Notification must be made by telephone or other electronic means, as soon as practicable, but in no event later than four (4) daytime business hours after the beginning of the occurrence.

(c) Failure to report a malfunction under subsection (b) of this condition of any emission unit or emission control equipment shall constitute a violation of 326 IAC 1-6, and any other applicable rules. Information of the scope and expected duration of the malfunction must be provided, including the items specified in 326 IAC 1-6-2(c)(3)(A) through (E).

(d) Malfunction is defined as any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner. [326 IAC 1-2-39]

C.20 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(31) (“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
Indiana Government Center North
100 North Senate Avenue, Room 13W
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(33).

C.21 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. Support information includes the following, where applicable:
  (AA) All calibration and maintenance records.
  (BB) All original strip chart recordings for continuous monitoring instrumentation.
  (CC) Copies of all reports required by the Part 70 permit.

Records of required monitoring information include the following, where applicable:
  (AA) The date, place, as defined in this permit, and time of sampling or measurements.
  (BB) The dates analyses were performed.
  (CC) The company or entity that performed the analyses.
  (DD) The analytical techniques or methods used.

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

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

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

C.22 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [40 CFR 64][326 IAC 3-8]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under Section C - Malfunctions Report 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(33). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

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

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

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

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

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

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

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(b) The address for report submittal is:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

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

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

Stratospheric Ozone Protection

C.23 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.

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SECTION D.1 **RESERVED**

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SECTION D.2 **RESERVED**

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SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source]

(b) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility]
[Under 40 CFR Part 63, Subpart UUUUU, 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 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3][326 IAC 6-2-1(g)][326 IAC 7-1.1-2]

Pursuant to Prevention of Significant Deterioration Approval to Construct EPA-5-A-80-18, issued on April 3, 1980, and the preconstruction approval from the Indiana Air Pollution Control Board, Construction Permit PC (37) 1460, issued on April 14, 1980:

(a) Each boiler unit (Units 17 and 18) shall not be operated in excess of 3,967 MMBtu per hour heat input. (in EPA-5-A-80-18 only)

(b) Stack gas particulate emissions shall be controlled to 0.03 pound or less of total suspended particulates per million BTU (lb/MMBtu) of heat input.

This requirement will be met by using electrostatic precipitators (ESP) which will provide a 99.8 percent guaranteed control efficiency. (in PC (37) 1460 only)

(c) The opacity of the exhaust gases shall not exceed twenty percent (20%) based on a six-minute average except for one six-minute period per hour of opacity not exceeding twenty-seven percent (27%). (EPA 5-A-80-18 only)

(d) Reserved.

(e) Nitrogen oxide emissions from each boiler shall not exceed 0.6 pound per million BTU (lb/MMBTU) of heat input.

(f) Reserved.

D.3.2 PSD Minor Limits [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (Preventive of Significant Deterioration (PSD)) not applicable to the 2026 Modification permitted under SSM No. 073-49556-00008, the Permittee shall comply with the following:

(a) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, the combined PM emissions from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 shall not exceed 91.0 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(b) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, the combined PM10 emissions from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 shall not exceed 345.0 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(c) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, the combined PM2.5 emissions from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 shall not exceed 292.0 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(d) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, the combined NOx emissions from Unit 17 and Unit 18 shall not exceed 1,560.0 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(e) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, the combined sulfuric acid mist (H2SO4) emissions from Unit 17 and Unit 18 shall not exceed 280.0 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

Compliance with these limits and Condition D.14.4, shall limit the potential to emit of PM, PM10, PM2.5, NOx, and H2SO4 to less than 25, 15, 10, 40, and 7 tons per twelve (12) consecutive month period, respectively, and shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2026 CCCT Project modification permitted under SSM No. 073-49556-00008 for these regulated NSR pollutants.

D.3.3 Alternative Fuel Blends [326 IAC 2-2]

(a) Pursuant to a letter from IDEM, OAQ, to Northern Indiana Public Service Company LLC dated June 13, 1996, based on the results of emissions testing performed in 1995 and subsequent ambient air modeling studies, petroleum coke may be combusted in Units 17 and 18 at a blend rate of no more than 30 percent (30%) petroleum coke (by weight). The conditions of the Units 17 and 18 federal PSD construction permit are not affected by this ruling, and all requirements contained therein still apply.

(b) The flue gas desulfurization (FGD) system shall be in operation at all times when pet coke is being fired. Should an emergency condition occur which causes a malfunction of

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the FGD system, the Permittee shall cease bunkering pet coke until the FGD system is fully operational.

D.3.4 Reserved

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

D.3.5 Compliance Determination

(a) Compliance with PM emissions limit from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 in Conditions D.3.2(a) shall be determined as follow:

$$PM = \sum_{i=1}^{12} (\mathrm{EU17} + \mathrm{EU18} + \mathrm{ECU17} + \mathrm{ECU18})$$

where:

PM = Total PM emissions (tons/year) from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18
i = Each calendar month within the twelve (12) consecutive month period
E_{U17} = PM emissions (tons/month) from Unit 17 calculated using the CEMS data.
E_{U18} = PM emission (tons/month) from Unit 18 calculated using the CEMS data.
E_{CU17} = PM emission (tons/month) from Colling Tower Unit 17 calculated using the following equation:

E_{CU17} = EF * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

E_{CU18} = PM emission (tons/month) from Colling Tower Unit 18 calculated using the following equation:

E_{CU17} = EF * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

(b) Compliance with PM10 emissions limit from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 in Conditions D.3.2(b) shall be determined as follow:

$$PM10 = \sum_{i=1}^{12} (\mathrm{EU17} + \mathrm{EU18} + \mathrm{ECU17} + \mathrm{ECU18})$$

where:

PM10 = Total PM10 emissions (tons/year) from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18
i = Each calendar month within the twelve (12) consecutive month period

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E_{U17} = PM10 emissions (tons/month) from Unit 17 calculated using the CEMS data.
E_{U18} = PM10 emission (tons/month) from Unit 18 calculated using the CEMS data.
E_{CU17} = PM10 emission (tons/month) from Colling Tower Unit 17 calculated using the following equation:

E_{CU17} = EF * 70% * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
70% = % PM to PM10 ratio according to California SCAQMD CEIDARS
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

E_{CU18} = PM emission (tons/month) from Colling Tower Unit 18 calculated using the following equation:

E_{CU17} = EF * 70% * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
70% = % PM to PM10 ratio according to California SCAQMD CEIDARS
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

(c) Compliance with PM2.5 emissions limit from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 in Conditions D.3.2(c) shall be determined as follow:

$$PM2.5 = \sum_{i=1}^{12} (\mathrm{EU17} + \mathrm{EU18} + \mathrm{ECU17} + \mathrm{ECU18})$$

where:

PM2.5 = Total PM2.5 emissions (tons/year) from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18
i = Each calendar month within the twelve (12) consecutive month period
E_{U17} = PM2.5 emissions (tons/month) from Unit 17 calculated using the CEMS data.
E_{U18} = PM2.5 emission (tons/month) from Unit 18 calculated using the CEMS data.
E_{CU17} = PM2.5 emission (tons/month) from Colling Tower Unit 17 calculated using the following equation:

E_{CU17} = EF * 40% * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
40% = % PM to PM2.5 ratio according to California SCAQMD CEIDARS
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

E_{CU18} = PM2.5 emission (tons/month) from Colling Tower Unit 18 calculated using the following equation:

E_{CU17} = EF * 40% * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
40% = % PM to PM2.5 ratio according to California SCAQMD CEIDARS
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

(d) Compliance with combined NOx emissions limit from Unit 17 and Unit 18 in Condition D.3.2(d) shall be determined using the continuous emissions monitoring data.

(e) Compliance with combined sulfuric acid mist (H2SO4) emissions limit from Unit 17 and Unit 18 in Condition D.3.2(e) shall be determined by calculating H2SO4 emissions using the emissions calculations used to calculate H2SO4 releases for the Toxics Release Inventory (TRI) program.

D.3.6 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A) (iii)]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment as specified in Section D.3.

(b) All continuous emission monitoring systems shall meet all applicable performance specifications of 40 CFR 60, 40 CFR 75 or any other performance specification, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

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

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

(1) If the CEM is required for monitoring NOx or SO2 emissions pursuant to 40 CFR 75 (Title IV Acid Rain program) or 326 IAC 24 (SO2 and NOx Trading Program), the Permittee shall comply with the relevant requirements of 40 CFR 75 Subpart D- Missing Data Substitution Procedures.

(2) If the CEM is not used to monitor NOx or SO2 emissions pursuant to 40 CFR 75 or 326 IAC 24 (SO2 and NOx Trading Program), then supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5, 40 CFR 60**,** or 40 CFR 75.

D.3.7 Operation of Electrostatic Precipitator

Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator (ESP) shall be operated at all times that the corresponding boilers are in operation.

D.3.8 Scrubber Operation

Except as otherwise provided by statute or rule or in this permit, the flue gas desulfurization (FGD) system shall be operated as needed to maintain compliance with all applicable SO_2 emission limits.

D.3.9 Reserved

D.3.10 Continuous Emissions Monitoring [326 IAC 2-2] [326 IAC 3-5] [326 IAC 7-2-1(g)][326 IAC 12]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions), Indiana Air Pollution Control Board Construction Permit PC (37) 1460, issued on April 14, 1980, and 326 IAC 2-2, continuous emission monitoring systems for Units 17 and 18 shall be calibrated, maintained, and operated for measuring opacity, SO_2, NO_X, and either CO_2 or O_2, which meet all applicable performance specifications of 326 IAC 3-5-2.

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

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

(d) 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, 326 IAC 10-4, 40 CFR 60, or 40 CFR 75.

D.3.11 Particulate Matter (PM) Continuous Emission Monitoring System [326 IAC 3-5] [326 IAC 2-7-5(3)(A)(iii)]

Compliance with the PM limitation in Condition D.3.1(b) shall be determined by use of a CEMS measuring PM emissions in accordance with the procedures in 40 CFR 63 Subpart UUUUU and this Condition. The Permittee shall certify, maintain, and operate a CEMS measuring PM emissions discharged from Unit 17 and Unit 18 to the atmosphere and record the output of the system as specified in paragraphs (a) through (e):

(a) The PM CEMS shall be certified, operated, and maintained pursuant to 40 CFR Part 60, Appendix B, Performance Specification #11 and 40 CFR 60.13(e).

(b) Compliance with the applicable particulate emission limitations in Condition D.3.1 shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data.

(c) For purposes of demonstrating compliance with the particulate emission limitation in Condition D.3.1, the Permittee shall adjust to 5% any measured carbon dioxide (CO2) values that are below 5%.

(d) 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.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3.

D.3.12 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3]

The Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the limits as established in PSD Approval to Construct EPA-5-A-80-18, issued on April 3, 1980, and Construction Permit PC (37) 1460, issued on April 14, 1980, using a thirty (30) day rolling arithmetic average of all hourly emission rates for SO_2 for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or emergency conditions for SO_2. Compliance with the percentage reduction requirements for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days.

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

D.3.13 PM Monitoring System Downtime

(a) Whenever the PM CEMS is malfunctioning or down for repair or adjustments for 24 hours or more, and a backup CEMS is not brought on-line, the following shall be used to provide information related to particulate emissions:

(1) The ability of the electrostatic precipitator to control particulate matter emissions shall be monitored once per day when Unit 17 or Unit 18 is in operation by measuring and recording the following:

(A) the primary and secondary currents of the T-R sets.

(B) the primary and secondary voltages of the T-R sets

(C) daily number of TR sets in service

D.3.14 SO_2 Monitoring System Downtime

Whenever both the primary and back up SO2 continuous emission monitoring systems (CEMS) are malfunctioning or down for repairs or adjustments for a period of twenty-four (24) hours or more, the Permittee shall monitor and record boiler load, recirculation pH, slurry valve position, and absorber level to demonstrate that the operation of the scrubber continues in a manner typical for the boiler load, and sulfur content of the coal fired. Scrubber parametric monitoring readings shall be recorded at least twice per day until the primary CEMS or a back-up CEMs is brought online, the following shall be used to provide information related to SO2 emissions:

(a) If the CEMS is down for less than twenty-four (24) hours, the Permittee shall substitute an average of the quality-assured data from the hour immediately before and the hour immediately after the missing data period for each hour of missing data.

(b) If the CEMS is down for twenty-four (24) hours or more:

(1) Either fuel sampling and fuel preparation and analysis shall be conducted in accordance with 326 IAC 3-7-2(b) and (c), 326 IAC 3-7-2(d) and 326 IAC 3-7-2(e) or, alternatively, a portable analyzer, properly calibrated according to manufacturer specifications (such as manufacturer operating or maintenance manuals), shall be used to monitor SO_2 emissions. To the extent the Permittee elects to conduct fuel sampling: the Permittee shall collect the coal sample as bunkered; coal shall be sampled at least three (3) times per day and at least one (1) time per eight (8) hour period unless no coal is bunkered during the preceding eight (8) hour period; and minimum sample size shall be five hundred (500) grams.

or

(2) Pursuant to 326 IAC 3-7-3, other manual and 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.

(c) To the extent the Permittee elects to conduct fuel sampling to comply with Condition D.3.12, 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 any information collected pursuant to 326 IAC 3-7-2 through 326 IAC 3-7-4 under this Condition D.3.12. In addition, any revision to the SOP shall be submitted to IDEM, OAQ.

D.3.15 NOx Monitoring System Downtime

(a) In the event that a breakdown of a NOx continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a NOx continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup NOx CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary NOx CEMS, the Permittee shall comply with the following:

(1) In instances of CEMS downtime, the Permittee shall report the NOx mass emissions in accordance with the procedures regulated by 40 CFR Part 75, Appendix D (Optional SO2 Emissions Data Protocol) for fuel flow meters requirements, 40 CFR Part 75, Appendix E (Optional NOx Emissions Estimation Protocol) for emission rate curve establishment, and Appendix G (Determination of CO2 Emissions). NOx mass emissions reported shall be based on the fueland-unit specific NOx emission rates ("load curve") established during the latest and most representative CEMS data.

(c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during operations, with at least four (4) hours between each set of readings, until a NOx CEMS is online.

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

D.3.16 Record Keeping Requirements

(a) To document the compliance status with requirements in Condition D.3.1(b), the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the limits established in Condition D.3.1(b).

(1) PM CEMS data when the PM CEMS is installed, certified, and operating to measure PM pursuant to this permit.

(2) All ESP Parametric monitoring readings when used as backup for the duration when PM CEMS are down.

(b) The Permittee shall maintain all PM continuous emissions monitoring data, with calendar dates and beginning and ending times of any CEM downtime, the reasons for each CEM downtime, and the efforts made to correct the problem.

(c) To document the compliance status with SO_2 Conditions D.3.1, D.3.8, D.3.10, and D.3.12, the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the SO_2 limit(s) as required in Conditions D.3.1, D.3.8, D.3.10, and D.3.12. The Permittee shall maintain records in accordance with (2) below during SO_2 CEM system downtime.

(1) All SO_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6, 326 IAC 7-2-1(g).

(2) All scrubber parametric monitoring readings taken during any periods of CEM downtime, in accordance with Condition D.3.12.

(d) To document the compliance status with NO_X Conditions D.3.1(e) and D.3.10, the Permittee shall maintain records of all NO_X and CO_2 or O_2 continuous emissions monitoring data, pursuant to 326 IAC 3-5-6 and 326 IAC 2-2. Records shall be complete and sufficient to establish compliance with the NO_X limits as required in Conditions D.3.1(e) and D.3.10.

(e) Reserved.

(f) To document the compliance status with Condition D.3.3, the Permittee shall maintain records of the amount of petroleum coke combusted and the pet coke/coal blend rate for each boiler. Records shall be complete and sufficient to establish compliance with the fuel limit of Condition D.3.3 using a thirty (30) day rolling weighted average.

(g) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, to document the compliance status with Condition D.3.2, the Permittee shall maintain monthly records in accordance with (1) through (5) below. Records maintained for (1) through (5) shall be taken as stated below and shall be complete and sufficient to establish compliance with the PM, PM10, PM2.5, NOx, and H2SO4 emission limits established in Condition D.13.2:

(1) Monthly PM emissions from the Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 as calculated in Condition D.3.5(a).

(2) Monthly PM10 emissions from the Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 as calculated in Condition D.3.5(b).

(3) Monthly PM2.5 emissions from the Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 as calculated in Condition D.3.5(c).

(4) Record the NOx output of the continuous monitoring system and perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7 for Unit 17 and Unit 18.

(5) Monthly H2SO4 emissions from Unit 17 and Unit 18 as calculated in Condition D.3.5(e).

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

D.3.17 Reporting Requirements

(a) Pursuant to 326 IAC 3-5-7, a quarterly report of PM, SO2, and NOx exceedances shall be submitted not later than thirty (30) days following the end of each calendar quarter. 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(33). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(b) A quarterly summary of the information to document the compliance status with Conditions D.3.2(a), D.3.2(b) and D.3.2(c) shall be submitted not later than thirty (30) days after the end of the quarter being reported. 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(33). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(c) Pursuant to 326 IAC 3-5-5(e), a quarterly report of the continuous emissions monitoring system performance audits shall be submitted not later than thirty (30) days following the end of each calendar quarter. 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(33). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(d) Pursuant to 326 IAC 3-5-7(5), a quarterly report of the continuous monitoring system instrument downtime shall be submitted not later than thirty (30) days following the end of each calendar quarter. 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(33). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

D.3.18 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) Pursuant 326 IAC 3-5-5(f)(1), the Permittee shall prepare and submit to IDEM, OAQ a written report for performance audits as follows:

(1) Owners or operators of emissions units required to conduct a:

(A) cylinder gas audit;
(B) relative accuracy test audit; or
(C) continuous opacity monitor calibration error audit;

on continuous emission monitors shall prepare a written report of the results of the performance audit for each calendar quarter, or for other periods required by the department. The owner or operator shall submit quarterly reports to the department within thirty (30) calendar days after the end of each quarter for cylinder gas audits and continuous opacity monitor calibration error audits and within forty-five (45) calendar days after the completion of the test for relative accuracy test audits.

(2) The report must contain the information required by 326 IAC 3-5-5(f)(2).

(b) Pursuant to 326 IAC 3-5-7(c)(4), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) date of downtime;
(2) time of commencement;
(3) duration of each downtime;
(4) reasons for each downtime; and
(5) nature of system repairs and adjustments.

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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:

(c) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, and exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

[Under 40 CFR Part 60, Subpart GG these units are affected facilities]

(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 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]

Pursuant to Prevention of Significant Deterioration Approval to Construct EPA-5-79-A-25, issued on August 16, 1979, and the preconstruction approval from the Indiana Air Pollution Control Board, Construction Permit PC (37) 1380, issued on May 9, 1979:

(a) Nitrogen oxide (NO_X) emissions from each turbine shall not exceed 93 ppm at 15% oxygen on a dry basis.

(b) Each turbine unit shall not operate in excess of 2,000 hours per twelve (12) consecutive month period with compliance determined at the end of each month.

D.4.2 Reserved

D.4.3 Reserved

D.4.4 Reserved

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

D.4.5 NOx Control

To the extent necessary to comply with Condition D.4.1, the water injection systems which are used to control the NOx emissions from turbines 16A and 16B shall be in operation and control emissions from turbines 16A and 16B.

D.4.6 Continuous Emissions Monitoring [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) and 326 IAC 2-2 (PSD), the Permittee is required to calibrate, certify, operate and maintain a continuous emission monitoring system (CEMS) for measuring NOx and O_2 emissions rates from the combustion turbine stacks in accordance with 326 IAC 3-5 to demonstrate compliance with Condition D.4.1(a).

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

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

(d) 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, 40 CFR 60, or 40 CFR 75.

D.4.7 Reserved

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

D.4.8 Record Keeping Requirements

(a) To document the compliance status with Conditions D.4.1(a) and D.4.5, the Permittee shall maintain records in accordance with (1) through (3) below. Records shall be complete and sufficient to establish compliance with the nitrogen oxides (NO_X) limits established in Conditions D.4.1(a).

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

(2) To document the compliance status with Condition D.4.5, the Permittee shall maintain records of:

(i) All continuous monitoring system data of fuel consumption and the ratio of water to fuel being fired; or

(i) All continuous emission monitoring system (CEMS) data of NO_x and O_2 whenever Permittee elects to use CEMS to monitor NO_x and O_2.

(b) To document the compliance status with Condition D.4.1(b), the Permittee shall maintain records of the date and times for all periods of turbine operation.

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

D.4.9 Reporting Requirements

(a) To document the compliance status with Condition D.4.1(a), the Permittee shall submit a quarterly summary of:

(1) The ratio of water to fuel if using the continuous monitoring method outlined in 40 CFR 60, Subpart GG; or

(2) The NO_x emissions if using the continuous emissions monitoring method outlined in Condition D.4.5.

The report submitted by the Permittee does require the certification by the “responsible official” as defined by 326 IAC 2-7-1(33).

(b) To document the compliance status with Condition D.4.1(b), the Permittee shall submit a quarterly summary of the hours of operation for each combustion turbine. These reports shall be submitted to the address listed in Section C - General Reporting Requirements, of this approval. 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(33). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

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SECTION D.5 **RESERVED**

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SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(d) Fuel storage and handling systems for Unit 17 and 18 boilers constructed in 1980.

(1) Rail car unloading of coal, with a multi-compartment baghouse for PM control and enclosure for ancillary dust control.

(2) Truck unloading of petroleum coke (petcoke).

(3) Coal pile unloading, coal storage pile(s), petcoke pile unloading, petcoke storage pile(s), material handling equipment, and conveyors.

(4) Transfer House with an estimated throughput of 4,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a multi-compartment baghouse for PM control. To produce petcoke blends, coal and petcoke are combined in rotary plow during transfer to conveyor.

(5) Crusher House with a designated capacity of 3,000 tons per hour, with enclosed transfer points within an enclosure for dust control, with a multi-compartment baghouse for PM control.

(6) Transfer House to tripper with an estimated throughput of 3,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a baghouse, identified as TFDC-XFR, for PM control, constructed in 2015.

(7) Two (2) tripper conveyors with an estimated combined throughput of 3,000 tons per hour with enclosure for ancillary dust control, with a baghouse, identified as TFDC-18 for PM control, constructed in 2015.

(8) Twelve (12) Fuel Silos (bunkers) with enclosure for dust control, with two (2) baghouses, identified as TFDC-17 and TFDC-18, for PM control, constructed in 2015.

[Under 40 CFR Part 60, Subpart Y this unit is an affected facility.]

Specifically Regulated Insignificant Activities [326 IAC 2-7-1(19)]:

(a) Conveyors as follows:

(1) Covered conveyor for coal or coke conveying of less than or equal to 360 tons per day;

(3) Uncovered coal conveying of less than or equal to 120 tons per day.

(4) Underground conveyors.

(b) Coal bunker and coal scale exhausts and associated dust collector vents.

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

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

D.6.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]

Pursuant to Approval to Construct EPA-5-A-80-18, issued on April 3, 1980:

(a) Particulate emissions from coal unloading shall not exceed ten percent (10%) opacity for the duration of the unloading operation.

(b) All coal conveyors shall be completely enclosed.

(c) All transfer points shall be completely enclosed except those at the storage pile.

(d) Particulate emissions from the crusher house, conveyor room and reclaim tunnels shall be controlled to 99 percent.

(e) Fugitive emissions from the coal piles shall be minimized by compaction and other appropriate measures (surfactant spray etc.).

D.6.2 Reserved

D.6.3 Particulate Emission Limitation for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), for the fuel storage and handling systems for Units 17 and 18 other than the coal storage piles, allowable particulate emissions for the coal handling operations shall be calculated as follows:

(a) Particulate shall not be emitted in excess of the amount shown in the table in 326 IAC 6-3-2(e). The allowable rate of emission shall be based on the process weight rate for the process.

(b) Interpolation of the data in the table in 326 IAC 6-3-2(e) for process weight rates up to sixty thousand (60,000) pounds per hour shall be accomplished by use of the equation:

$E = 4.10\ P^{0.67}$

where:
E = rate of emission in pounds per hour and
P = process weight rate in tons per hour.

(c) Interpolation and extrapolation of the data in the table in 326 IAC 6-3-2(e) for process weight rates 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.

(d) When the process weight rate exceeds two hundred (200) tons per hour, the allowable emission may exceed that shown in the table in 326 IAC 6-3-2(e), provided the concentration of particulate in the discharge gases to the atmosphere is less than one-tenth (0.10) pound per one thousand (1,000) pounds of gases.

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

D.6.4 Particulate Control

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 bag will be repaired or replaced, the Permittee shall promptly notify the IDEM, OAQ of the expected date the failed bag will be repaired or replaced. The notification shall also include the results of any

response actions taken up to the time of notification.

D.6.5 Reserved

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

D.6.6 Visible Emissions Notations

(a) Visible emission notations of the rail car unloading station openings shall be performed once per day during normal daylight operations when unloading coal. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of the fuel transfer exhaust points shall be performed once per week during normal daylight operations when transferring fuel. A trained employee shall record whether emissions are normal or abnormal.

(c) Visible emission notations of the coal crusher exhaust shall be performed once per week during normal daylight operations when the crusher is in operation. A trained employee shall record whether emissions are normal or abnormal.

(d) If abnormal emissions of dust are observed from the rail car unloading station openings, the fuel transfer exhaust points, or the coal crusher exhaust, the Permittee shall take reasonable response. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

(e) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation.

(f) 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.

(g) 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.

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

D.6.7 Record Keeping Requirements

(a) To document the compliance status with Condition D.6.6(a) - Visible Emission Notations, the Permittee shall maintain daily records of the visible emission notations of the coal rail car unloading station openings. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that day).

(b) To document the compliance status with Condition D.6.6(b) and (c) - Visible Emission Notations, the Permittee shall maintain weekly records of the visible emission notations of the coal transfer exhaust points and crusher baghouse exhaust. 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 obligations with regard to the record keeping required by this condition.

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SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(e) Material handling for the flue gas desulfurization systems for Unit 17 and 18 boilers, constructed 1980, including the following:

(1) One (1) limestone slurry preparation system with a maximum hourly throughput rate of 38,941 pounds of limestone per hour, constructed in 1980.

(2) Three (3) ground limestone pneumatic truck unloading systems connected to Unit 17 and Unit 18 limestone silos, constructed in 1980, with baghouses for PM control.

(3) One (1) gypsum conveying system, with a maximum design throughput of 150 tons per hour, constructed in 1980. All gypsum is handled wet.

(4) One (1) radial stacker, identified as 7MX04G-RS, shared among Unit 17 and 18, with rated capacity of 220 tons/hour, constructed in 2013.

(5) One (1) radial stacker, identified as 8MX04G-RS, shared among Units 17 and 18, with rated capacity of 220 tons/hour, constructed in 2016.

(i) Material handling for the flue gas desulfurization systems for Unit 17and Unit 18 boilers, including the following:

(1) Transportation of limestone by truck on paved road.

(2) Three (3) storage silos originally used for dual-alkali FGD system with baghouses for PM control.

(3) Two (2) upgraded incline belt conveyors constructed in 2013 and shared among Units 17 and 18 for transfer of dewatered gypsum to the radial stackers.

(4) Transportation of off-specification gypsum by truck on unpaved roads.

Specifically Regulated Insignificant Activities [326 IAC 2-7-1(19)]:

(a) Conveyors as follows:

(2) Covered conveyors for limestone conveying of less than or equal to 7,200 tons per day for sources other than mineral processing plants constructed after August 31, 1983.

(4) Underground conveyors.

(g) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(4) Gypsum stockpiles.

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

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

D.7.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the limestone handling systems and gypsum transfer systems shall not exceed 30 pounds per hour, each, when operating at a process weight rate of 38,941 pounds per hour. This pounds per hour limitation was calculated using 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) Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the two (2) radial stackers, identified as 7MX04G-RS and 8MX04G-RS, shall not exceed 59.55 pounds per hour, each, when operating at a process weight rate of 220 tons per hour. This pounds per hour limitation was calculated using 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:

$E = 55.0 P^{0.11} - 40$

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) when the process weight rate exceeds 200 tons per hour, the allowable emission may exceed the calculated (E) pounds per hour rate, provided the concentration of particulate in discharge gases to the atmosphere shall be less than 0.10 pounds per one thousand (1000) pounds of gases.

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SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(f) Dry fly ash handling and disposal.

(1) Pneumatic fly ash conveyance to storage silos, with a design capacity of 63 tons per hour of fly ash from each of Units 17 and 18.

(2) Fly ash storage silos for Units 17, and 18, with cyclone separators, filter/separators, silo collector bag filters, and silo bin vent bag filters. Each silo has wet and dry unloaders, each with a design unloading capacity of 300+ tons per hour, with particulate emissions controlled by the use of a telescoping chute with a vacuum system and a bin vent filter when the ash is being loaded dry, and controlled by the use of water spray mixed with the ash when the ash is being loaded wet.

(3) Transportation by truck via in-plant haul roads; and onsite disposal area.

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

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

D.8.1 Prevention of Significant Deterioration (PSD) [326 IAC 2-2-3]

For the fly ash from Units 17 and 18, pursuant to Approval to Construct EPA-5-A-80-18, issued on April 3, 1980:

Fly ash handling, storage and transport shall be controlled by wetting and/or by installation of baghouses. Trucks utilized for dry or unconditioned ash disposal shall be covered. (in EPA-5-A-80-18 only)

D.8.2 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the Pneumatic fly ash conveyance from each of Units 17 and 18 shall not exceed 46.8 pounds per hour when operating at a process weight rate of 63 tons per hour of fly ash from each of Units 17 and 18. These pounds per hour limitations were calculated using the following equation:

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

$E = 55.0\ P^{0.11} - 40$

Where:
E = rate of emission in pounds per hour; and
P = process weight rate in tons per hour

(b) Pursuant to 326 IAC 6-3-2(e)(3) (Particulate Emission Limitations for Manufacturing Processes), for dry fly ash silo unloading at a throughput 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.

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

D.8.3 Visible Emissions Notations

(a) Visible emission notations of the ash silo unloading station openings shall be performed at least once per day during normal daylight operations when ash is being unloaded. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of the fly ash conveyance and silo bag filter and bin vent filter exhausts shall be performed at least once per day during normal daylight operations when transferring ash to the corresponding silo. A trained employee shall record whether emissions are normal or abnormal.

(c) Visible emission notations of the nozzle of each telescoping chute shall be performed at least once per day during normal daylight operations when unloading ash through the chute. A trained employee shall record whether emissions are normal or abnormal.

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

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

(f) 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.

(g) 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.

(h) 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.

D.8.4 Broken or Failed Bag Detection

In the event that bag failure has been observed:

For bin vent filters, if failure is indicated by an opacity violation, or if filter failure is determined by other means, such as gas temperatures, flow rates, air infiltration, leaks, dust traces or triboflows, then failed unit and the associated process will be shut down immediately until the failed unit has been repaired or replaced.

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

D.8.5 Record Keeping Requirements

(a) To document the compliance status with Condition D.8.3 - Visible Emission Notations, the Permittee shall maintain daily records of the visible emission notations of the Unit 17 and 18 ash silo unloading station openings, the Unit 17 and 18 baghouse stack exhaust, and nozzle of each telescoping chute. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g., the process did not operate that day).

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

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SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(g) Wet process bottom ash handling, with sluicing lines conveying ash to storage ponds in the Waste Disposal Area.

(h) Ponded bottom ash handling/removal operations.

Insignificant Activities:

(g) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(2) Wet handling of FGD sludge material collected from the FGD building sumps, sluiced to the Material Storage Runoff Pond. FGD material dredged from pond inlet area is dewatered on the pond bank with trucks conveying dewatered material to onsite landfill.

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

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

D.9.1 Prevention of Significant Deterioration (PSD) and Construction Permit Limitations [326 IAC 2-2-3]

Pursuant to Approval to Construct EPA-5-A-80-18, issued on April 3, 1980, and Indiana Air Pollution Control Board Construction Permit PC (37) 1460, issued on April 14, 1980, with respect to Units 17 and 18:

(a) The bottom ash shall be sluiced to waste disposal ponds. (in PC (37) 1460 only)

(b) Bottom ash handling, storage and transport shall be controlled by wetting and/or by installation of baghouses. (in EPA-5-A-80-18 only)

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

D.9.2 Visible Emissions Notations

(a) Visible emission notations of any active onsite landfill area(s) shall be performed at least once per day during normal daylight operations. Any storage pond in the Waste Disposal Area or the Material Storage Runoff Pond area that contains either bottom ash and/or FGD sludge shall be observed once per week to determine if sufficient water is present in the pond to cover or saturate bottom ash and/or sludge deposited in the pond. During any period when there is not sufficient water in the pond to cover or saturate bottom ash and/or sludge present in the pond, visible emission notations of such storage pond area(s) shall be performed at least once per day during normal daylight operations. When daily visible emission notations are made, a trained employee shall record whether emissions are normal or abnormal.

(b) If visible emissions are observed crossing the property line or boundaries of the property, right-of-way, or easement on which the source is located, the Permittee shall take reasonable response. Section C - Response to Excursions and Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. Failure to take response steps shall be considered a deviation from this permit.

(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.

(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.

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

D.9.3 Record Keeping Requirements

(a) To document the compliance status with Condition D.9.2 - Visible Emission Notations, the Permittee shall maintain records of visible observations, and any resulting visible emission notations of the Waste Disposal Area and the Material Storage Runoff Pond area, and records of visible emission notations relating to any active onsite landfill area(s).The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that day).

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

SECTION D.10 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Insignificant Activities:

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

(d) Any of the following structural steel and bridge fabrication activities:

(1) Cutting 200,000 linear feet or less of one inch (1") plate or equivalent.

(2) Using 80 tons or less of welding consumables.

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

(g) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(3) Shot blasters.

(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.10.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) 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.

(b) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), particulate emission rate from the brazing, cutting, soldering, welding, grinding, and machining operations shall not exceed an amount determined by the following, for a process weight rate equal to or greater than 100 pounds per hour:

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.

SECTION D.11 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Specifically Regulated Insignificant Activities [326 IAC 2-7-1(19)]:

(g) Other activities or categories not previously identified with potential, uncontrolled emissions equal to or less than thresholds require listing only: Pb 0.6 ton per year or 3.29 pounds per day, SO_2 5 pounds per hour or 25 pounds per day, NO_X 5 pounds per hour or 25 pounds per day, CO 25 pounds per day, PM 5 pounds per hour or 25 pounds per day, VOC 3 pounds per hour or 15 pounds per day:

(5) Cold Cleaner degreasing operations

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

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

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

D.11.1 Cold Cleaner Degreaser Control Equipment and Operating Requirements [326 IAC 8-3-2]

Pursuant to 326 IAC 8-3-1 and 8-3-2 (Cold Cleaner Degreaser Control and Equipment Operating Requirements), the Permittee shall:

(a) Pursuant to 326 IAC 8-3-1(c)(1)(B) for equipment constructed after January 1, 1980, ensure the following control equipment and operating requirements are met:

(1) Equip the degreaser with a cover.

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

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

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

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

(6) Store waste solvent only in closed containers.

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

(b) Pursuant to 326 IAC 8-3-1(c)(2)(A)(ii) for equipment constructed after July 1, 1990, 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.

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

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

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

D.11.2 Material Requirements for Cold Cleaner Degreasers [326 IAC 8-3-8]

Pursuant to 326 IAC 8-3-8 (Material Requirements for Cold Cleaner Degreasers), on and after January 1, 2015, the Permittee shall not operate a cold cleaning degreaser with a solvent that has a VOC composite partial vapor pressure that exceeds one (1) millimeter of mercury (nineteen-thousandths (0.019) pound per square inch) measured at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

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

D.11.3 Record Keeping Requirements

To document the compliance status with Condition D.11.2, on and after January 1, 2015, the Permittee shall maintain the following records for each purchase of solvent used in the cold cleaner degreasing operations. These records shall be retained on-site or accessible electronically for the most recent three (3) year period and shall be reasonably accessible for an additional two (2) year period.

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

(b) The date of purchase.

(c) The type of solvent purchased.

(d) The total volume of the solvent purchased.

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

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

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SECTION D.12 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(j) One (1) natural gas-fired temporary boiler, constructed in 2020, with a rated maximum capacity of less than or equal to 99.9 MMBtu per hour, and exhausting outdoors.

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

Pursuant to 326 IAC 6-2-1(f) (Particulate Emission Limitations for Sources of Indirect Heating), the particulate emissions from the temporary boiler shall be limited to 0.10 pound per MMBtu heat input.

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SECTION D.13 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a rated maximum heat input capacity of 519 MMBtu per hour, each using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR 60, Subpart KKKK these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa these units are intermediate load affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a rated maximum heat input capacity of 2,416 MMBtu per hour, using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR 60, Subpart KKKK this unit is an affected facility]
[Under 40 CFR 60, Subpart TTTTa this unit is an intermediate load affected facility]
[Under 40 CFR 63, Subpart YYYY, this unit 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.13.1 PSD Minor Limit for PM and VOC [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (Preventive of Significant Deterioration (PSD)) not applicable to the 2024 Modification permitted under SSM No. 157-47965-00044, the Permittee shall comply with the following:

(a) The combined PM emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20 shall not exceed 61.04 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(b) The combined VOC emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, shall not exceed 79.70 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

Compliance with these limits shall limit the potential to emit PM and VOC to less than 25 and 40 tons per twelve (12) consecutive month period, respectively, and shall render the requirements of 326 IAC 2-2 (Preventive of Significant Deterioration (PSD)) not applicable to the 2024 Modification permitted under SSM No. 073-47965-00008.

D.13.2 Best Available Control Technology (BACT) - VOC [326 IAC 8-1-6]

Pursuant to 326 IAC 8-1-6 (New Facilities; General Reduction Requirements), the Permittee shall minimize VOC emissions from the frame-type natural gas-fired combustion turbine, identified as Unit 20, using the Best Available Control Technology (BACT), which has been determined to be the following:

(a) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) shall be controlled by good combustion practices.

(b) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) during steady state operation shall not exceed 6.50 pounds per hour.

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

D.13.3 Testing Requirements [326 IAC 2-1.1-11]

In order to verify the emission rates for NOx and demonstrate compliance with VOC limitation under Condition D.13.2(b), not later than 180 days after the startup of the following emission units, the Permittee shall perform NOx and VOC testing on the following emission units:

Emission Unit	Emission Unit ID	Pollutant	Testing Frequency
One (1) of the three (3) aero-derivative combustion turbines	Units 19A, 19B, and 19C	NOx (45.90 lb/hr)	One time
Frame type combustion turbine	Unit 20	NOx (139.80 lb/hr) VOC (6.50 lb/hr)	One time

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

D.13.4 Continuous Emissions Monitoring [326 IAC 3-5][326 IAC 2-7-6(1),(6)][40 CFR 60, Subpart KKKK]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous emission monitoring systems for the natural gas-fired combustion turbines Units 19A, 19B, 19C, and 20, shall be calibrated, maintained, and operated for measuring NOx, which meet all applicable performance specifications of 326 IAC 3-5-2.

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

(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, 40 CFR 60, Subpart KKKK.

D.13.5 Compliance determination for PM and VOC

(a) To determine the compliance status with Condition D.13.1(a), the following equation shall be used to determine combined PM emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and 20 using the equation shown below for each:

$$E_{PM} = \sum_{i=1}^{12} \left(\sum_{n} \frac{[(ER_N * H) + (ER_{(SU/SD)} * Evt)]}{2000} \right)$$

Where:

E_{PM} = Total PM emissions (tons/year) form the combustion turbine Units 19A, 19B, 19C, 20

ER_N = 4.90 lb/hr PM emission rate in steady state operation for Units 19A, 19B, and 19C or 11.6 lb/hour PM emission rate in steady state operation for Unit 20, or value established in latest stack tests

$ER_{(SU/SD)}$ = 4.90 lb/event, PM emission rate in startup/shutdown events for Units 19A, 19B, and 19C or 11.60 lb/event, PM emission rate in startup/shutdown events for Unit 20

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Evt = Number of events for the month for Units 19A, 19B, 19C, and 20, where one event is a startup and shutdown cycle
H = Number of hours of steady state operation for the month for Units 19A, 19B, 19C, and 20
i = Each calendar month within the twelve (12) consecutive month period
n = Each combustion turbine Unit (Units 19A, 19B, 19C, and 20)

(b) To determine the compliance status with Condition D.13.1(b), the following equation shall be used to determine the combined VOC emissions from the four (4) natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and 20:

$$E_{VOC} = \sum_{i=1}^{12}\left(\sum_{n}\frac{[(ER_N * H) + (ER_{(SU/SD)} * Evt)]}{2000}\right)$$

Where:

E_{VOC} = Total VOC emissions (tons/year) from the combustion turbine Units 19A, 19B, 19C, 20
ER_N = 5.40 lb/hr, VOC emission rate in steady state operation for Units 19A, 19B, and 19C, or 6.50 lb/hr VOC emission rate in steady state operation for Unit 20, or value established in latest stack test.
$ER_{(SU/SD)}$ = 1.40 lb/event, VOC emission rate in startup/shutdown events for Units 19A, 19B, and 19C, or 101.00 lb/event, VOC emission rate in startup/shutdown events for Unit 20
Evt = Number of events for the month for Units 19A, 19B, 19C, and 20, where one event is a startup and shutdown cycle
H = Number of hours of steady state operation for the month for Units 19A, 19B, 19C, and 20
i = Each calendar month within the twelve (12) consecutive month period
n = Each combustion turbine Unit (Units 19A, 19B, 19C, and 20)

D.13.6 Startup & Shutdown Definition

For periods of startup and shutdown:

(1) Startup begins at the first firing of fuel in the stationary combustion turbine. For simple cycle turbines, startup ends when the stationary combustion turbine has reached steady state operation or after 1 hour, whichever is less.

(2) Shutdown is defined as the period of time the stationary combustion turbine exits steady state operating condition and ending with termination of combustion in the stationary combustion turbine.

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

D.13.7 NOx Continuous Emissions Monitoring (CEMS) Equipment Downtime

(a) In the event that a breakdown of a NOx continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a NOx continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup NOx CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary NOx CEMS, the Permittee shall comply with the following:

(1) In instances of CEMS downtime, the Permittee shall report the NOx mass emissions in accordance with the procedures regulated by 40 CFR Part 75, Appendix D (Optional SO2 Emissions Data Protocol) for fuel flow meters

requirements, 40 CFR Part 75, Appendix E (Optional NOx Emissions Estimation Protocol) for emission rate curve establishment, and Appendix G (Determination of CO2 Emissions). NOx mass emissions reported shall be based on the fuel-and-unit specific NOx emission rates ("load curve") established during the latest and most representative CEMS data.

(c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during operations, with at least four (4) hours between each set of readings, until a NOx CEMS is online.

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

D.13.8 Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) Permittee shall record the output of the continuous monitoring system (lb/hr) and shall perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(b) In the event that a breakdown of the NOx continuous emission monitoring systems (CEMS) occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

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

D.13.9 Record Keeping Requirements

(a) To document the compliance status with Condition D.13.1, the Permittee shall maintain monthly records in accordance with (1) and (2) below. Records maintained for (1) and (2) shall be taken as stated below and shall be complete and sufficient to establish compliance with the PM and VOC emission limits established in Condition D.13.1:

(1) Monthly PM emissions from the combustion turbine Units 19A, 19B, 19C and 20 as calculated using the equation in Condition D.13.5(a).

(2) Monthly VOC emissions from the combustion turbine Units 19A, 19B, 19C, and 20 as calculated using the equation in Condition D.13.5(b).

(b) The number of startup and shutdown events per month.

(c) The number of minutes for each startup event and each shutdown event.

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

D.13.10 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5-5(f)(1), the Permittee shall prepare and submit to IDEM, OAQ a written report for performance audits as follows:

(1) Owners or operators of emissions units required to conduct a:

(A) cylinder gas audit;
(B) relative accuracy test audit; or
(C) continuous opacity monitor calibration error audit;

on continuous emission monitors shall prepare a written report of the results of the performance audit for each calendar quarter, or for other periods required by the department. The owner or operator shall submit quarterly reports to the department within thirty (30) calendar days after the end of each quarter for cylinder gas audits and continuous opacity monitor calibration error audits and

within forty-five (45) calendar days after the completion of the test for relative accuracy test audits.

(2) The report must contain the information required by 326 IAC 3-5-5(f)(2).

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(33).

(b) Pursuant to 326 IAC 3-5-7(c)(4), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) date of downtime;
(2) time of commencement;
(3) duration of each downtime;
(4) reasons for each downtime; and
(5) nature of system repairs and adjustments.

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(33).

D.13.11 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.13.1 shall be submitted not later than thirty (30) days after the end of the quarter being reported. 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(33). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

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SECTION D.14 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(o) Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a rated maximum capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a rated maximum heat input of 987 MMBtu per hour, using dry low-NOx combustors and voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(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.14.1 PSD and VOC/BACT Emission Limitations (Steady State Operations) [326 IAC 2-2-3] [326 IAC 8-1-6]

Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the “Best Available Control Technology” (BACT) emission controls shall be used for the combustion turbines, identified as 21A, 21B, 22A, and 22B, as follows:

(a) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 1.00 ppmvd @ 15% O_2 on 3-hour average basis, excluding during periods of startup and shutdown for the combustion turbines for both simple cycle and combined cycle operations.

(b) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 2.00 ppmvd @15% O_2 on 3-hour average basis, excluding during periods of startup and shutdown when the combined cycle turbines are operated with duct burners.

(c) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 9.60 lb/hr on a 3-hour average basis, excluding during periods of startup and shutdown, when operating in combined cycle mode without duct burner.

(d) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 15.40 lb/hr on a 3-hour average basis, excluding during periods of startup and shutdown, when operating in combined cycle mode with duct burner.

(e) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 9.10 lb/hr on a 3-hour average basis, excluding during periods of startup and shutdown, when operating in simple cycle mode.

(f) VOC emissions from the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall be controlled using an oxidation catalyst and conducting good combustion practices.

D.14.2 PSD and VOC/BACT Emission Limitations (Startup, Shutdown and Malfunction) [326 IAC 2-2-3] [326 IAC 8-1-6]

The total VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, during any periods of startup and shutdown operation shall not exceed 25.60 tons per 12-month rolling.

D.14.3 CO_2e PSD/BACT Emission Limitations [326 IAC 2-2-3]

Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the combustion turbines, identified as 21A, 21B, 22A, and 22B, as follows:

(a) CO_2 emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 1,170 lb/MW-hr (gross) per twelve (12) operating month period average when operating in simple cycle mode.

(b) CO_2 emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 800 lb/MW-hr (gross) per twelve (12) operating month period average when operating in combined cycle mode.

(c) CO_2e emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall be limited through the use of good combustion practices and energy efficient design.

(d) The total GHGs (CO2, CH4, and N2O) emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, when operating in simple cycle mode, including steady state operation and operation during any periods of startup and shutdown, shall not exceed 863,649 tons per twelve (12) consecutive month period with compliance determined at the end of each month (GWPs per 78 FR 71948).

(e) The total GHGs (CO2, CH4, and N2O) emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, when operating in combined cycle mode, including steady state operation and operation during any periods of startup and shutdown, shall not exceed 1,751,087 tons per twelve (12) consecutive month period with compliance determined at the end of each month (GWPs per 78 FR 71948).

D.14.4 PSD Minor Limits [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (Preventive of Significant Deterioration (PSD)) not applicable to the 2026 CCCT Project Modification permitted under SSM No. 073-49556-00008, the Permittee shall comply with the following:

(a) The combined PM emissions from the four (4) combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B shall not exceed 120.3 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(b) The combined NOx emissions from the four (4) combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B shall not exceed 1,566.3 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

Compliance with these limits, shall limit the potential to emit of PM and NOx to less than 25 and 40 tons per twelve (12) consecutive month period, respectively, and shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2026 Modification permitted under SSM No. 073-49556-00008.

D.14.5 PSD Minor Limit [326 IAC 2-2]

(a) In order to render the requirements of 326 IAC 2-2 (Preventive of Significant Deterioration (PSD)) not applicable to the 2026 CCCT Project Modification permitted under SSM No. 073-49556-00008, the Permittee shall not begin operation of the final combustion turbine (Unit 21A, Unit 21B, Unit 22A, or Unit 22B and their associated duct burners) under 2026 CCCT Project until after the contemporaneous period of 2024 Peaker project has ended (*i.e.* the final combustion turbine (Unit 19A, Unit 19B, Unit 19C, or Unit 20) is started up).

(b) On and after the date of startup, of the first CT under the 2026 CCCT project, Unit 17, Unit 18, Unit 17 cooling tower, and Unit 18 cooling tower must comply with the emission limtiations established in D.3.2.

Compliance with these conditions shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2026 CCCT Project Modification permitted under SSM No. 073-49556-00008.

D.14.6 Particulate Emissions Limitations for Sources of Indirect Heating [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-1(f) (Particulate Emission Limitations for Sources of Indirect Heating), the particulate emissions from the heat recovery steam generator (HRSG) with duct burner shall be limited to 0.10 pound per MMBtu heat input.

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

D.14.7 VOC Control

In order to assure compliance with Conditions D.14.1, the oxidation catalysts for VOC control shall be in operation and control VOC emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, at all times these combustion turbines are in steady state operation.

D.14.8 Testing Requirements [326 IAC 2-1.1-11]

In order to verify the emission rates for VOC and CO and demonstrate compliance with Conditions D.14.1(a) and D.14.1(b), not later than 180 days after the initial startup of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, the Permittee shall perform VOC and CO testing of the following combustion turbines utilizing methods as approved by the Commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be alternated between the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, such that testing shall not be repeated until each combustion turbine has been tested. 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.

Emission Unit	Control Device	Pollutant/ Parameter	Frequency of Testing
	Oxidation Catalysts (OXCA21A,	VOC (1.0 ppmvd @ 15% O_2)[1]	Every 5 years
		VOC (2.0 ppmvd @ 15% O_2)[2]	

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Emission Unit	Control Device	Pollutant/ Parameter	Frequency of Testing
Combustion Turbines 21A, 21B, 22A, and 22B	OXCA21B, OXCA22A, and OXCA22B)	VOC (9.60 lb/hr)[1]	
		VOC (15.40 lb/hr)[2]	
		VOC (9.10 lb/hr)[3]	
		CO (16.80 lb/hr)[1]	Every 5 years
		CO (21.50 lb/hr)[2]	
		CO (15.90 lb/hr)[3]	
[1] When operating in combined cycle mode without duct burner [2] When operating in combined cycle mode with duct burner [3] When operating in simple cycle mode			

D.14.9 Continuous Emissions Monitoring [326 IAC 3-5][326 IAC 2-7-6(1),(6)][40 CFR 60, Subpart KKKK]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous emission monitoring systems for the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall be calibrated, maintained, and operated for measuring NOx, which meet all applicable performance specifications of 326 IAC 3-5-2.

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

(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, 40 CFR 60, Subpart KKKK.

D.14.10 Startup & Shutdown Definition

For periods of startup and shutdown:

(1) Startup begins at the first firing of fuel in the stationary combustion turbine. For simple cycle turbines, startup ends when the stationary combustion turbine has reached steady state operation or after 1 hour, whichever is less. For combined cycle stationary combustion turbines, startup ends when the stationary combustion turbine has reached steady state operation or after 3 hours, whichever is less. Stationary combustion turbines in combined cycle configurations that are operating as simple cycle must meet the startup requirements for simple cycle stationary combustion turbines.

(2) Shutdown is defined as the period of time the stationary combustion turbine exits steady state operating condition and ending with termination of combustion in the stationary combustion turbine.

D.14.11 Compliance Determination

(a) To determine the compliance status with Condition D.14.2, the following equation shall be used to determine total VOC emissions from each combustion turbine (Unit 21A, Unit 21B, Unit 22A, and Unit 22B) during any periods of startup and shutdown operation:

$$E_{VOC} = \sum_{i=1}^{12} \left(\frac{[(ER_{S(SU/SD)} * Evt_S)]}{2000} + \frac{[(ER_{C(SU/SD)} * Evt_C)]}{2000} \right)$$

Where:

E_{VOC} = Total VOC emissions (tons/year) form the combustion turbine
$ER_{S(SU/SD)}$ = 140 lb/event, VOC emission rate during startup/shutdown events in simple cycle for the combustion turbine
$ER_{C(SU/SD)}$ = 140 lb/event, VOC emission rate during startup/shutdown events in combined cycle operation for the combustion turbine

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Evt_S = Number of events per month during simple cycle operation for the combustion turbine, where one event is a startup and shutdown cycle
Evt_C = Number of events per month during combined cycle operation for the combustion turbine, where one event is a startup and shutdown cycle
i = Each calendar month within the twelve (12) consecutive month period

(b) To determine the compliance status with Condition D.14.3(d), the following equation shall be used to determine GHGs emissions from each combustion turbine (Unit 21A, Unit 21B, Unit 22A, and Unit 22B) when operating in simple cycle mode shall be determined using the following equation:

$$E_{GHGs} = \sum_{i=1}^{12} \left(\frac{[(ER_S * H_S) + (ER_{S(SU/SD)} * Evt_S)]}{2000} \right)$$

Where:

E_{GHGs} = Total GHGs emissions (tons/year) form each combustion turbine
ER_S = 446,445 lb/hr, GHGs emission rate during simple cycle steady state operation for the combustion turbine, or value established in latest stack test
$ER_{S(SU/SD)}$ = 446,445 lb/event, GHGs emission rate during startup/shutdown events in simple cycle for the combustion turbine
Evt_S = Number of events per month during simple cycle operation for the combustion turbine, where one event is a startup and shutdown cycle
H_S = Number of hours during simple cycle operation per month for the combustion turbine
i = Each calendar month within the twelve (12) consecutive month period

(c) To determine the compliance status with Condition D.14.3(e), the following equation shall be used to determine GHGs emissions from each combustion turbine (Unit 21A, Unit 21B, Unit 22A, and Unit 22B) when operating in combined cycle mode shall be determined using the following equation:

$$E_{GHGs} = \sum_{i=1}^{12} \left(\frac{[(ER_C * H_C) + (ER_{CDB} * H_{CDB}) + (ER_{C(SU/SD)} * Evt_C)]}{2000} \right)$$

Where:

E_{GHGs} = Total GHGs emissions (tons/year) form each combustion turbine
ER_C = 473,770 lb/hr, GHGs emission rate during combined cycle steady state operation without duct burner for the combustion turbine, or value established in latest stack test
ER_{CDB} = 601,899 lb/hr, GHGs emission rate during combined cycle steady state operation with duct burner for the combustion turbine, or value established in latest stack test
$ER_{C(SU/SD)}$ = 466,514 lb/event, GHGs emission rate during startup/shutdown events in combined cycle operation for the combustion turbine
Evt_C = Number of events per month during combined cycle operation for the combustion turbine, where one event is a startup and shutdown cycle
H_C = Number of hours during combined cycle operation without duct burner per month for the combustion turbine
H_{CDB} = Number of hours during combined cycle operation with duct burner per month for the combustion turbine
i = Each calendar month within the twelve (12) consecutive month period

(d) To determine the compliance status with Condition D.14.4(a), the following equation shall be used to determine combined PM emissions from the combustion turbines, identified as

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Unit 21A, Unit 21B, Unit 22A, and Unit 22B:

$$E_{PM} = \sum_{i=1}^{12}\left(\sum_{n}\frac{[(ER_S * H_S) + (ER_{S(SU/SD)} * Evt_S)]}{2000} + \sum_{n}\frac{[(ER_C * H_C) + (ER_{CDB} * H_{CDB}) + (ER_{C(SU/SD)} * Evt_C)]}{2000}\right)$$

Where:

E_{PM} = Total PM emissions (tons/year) form the combustion turbines 21A, 21B, 22A, and 22B

ER_S = 8.05 lb/hr, PM emission rate during simple cycle steady state operation for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B or value established in latest stack test

ER_C = 6.60 lb/hr, PM emission rate during combined cycle steady state operation without duct burner for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B or value established in latest stack test

ER_{CDB} = 12.30 lb/hr, PM emission rate during combined cycle steady state operation with duct burner for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B or value established in latest stack test

$ER_{S(SU/SD)}$ = 8.55 lb/event, PM emission rate during startup/shutdown events in simple cycle for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B

$ER_{C(SU/SD)}$ = 17.10 lb/event, PM emission rate during startup/shutdown events in combined cycle operation for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B

Evt_S = Number of events per month during simple cycle operation for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B, where one event is a startup and shutdown cycle

Evt_C = Number of events per month during combined cycle operation for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B, where one event is a startup and shutdown cycle

H_S = Number of hours during simple cycle operation per month for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B

H_C = Number of hours during combined cycle operation without duct burner per month for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B

H_{CDB} = Number of hours during combined cycle operation with duct burner per month for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B

i = Each calendar month within the twelve (12) consecutive month period

n = Each combustion turbine Unit 21A, Unit 21B, Unit 22A, and Unit 22B

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

D.14.12 Oxidation Catalyst Parametric Monitoring [40 CFR 64]

(a) In order to assure compliance with Conditions D.14.1, a continuous monitoring system shall be calibrated, maintained, and operated on each oxidation catalyst for measuring operating temperature. For the purpose of this condition, continuous means no less often than once per fifteen (15) minutes excluding periods of startup and shutdown. The output of this system shall be recorded as 4-hour average. From the date of startup until the stack test results are available, the Permittee shall operate the oxidation catalyst at or above the 4-hour average temperature of 500°F.

(b) The Permittee shall determine the 4-hour average temperature from the latest valid stack test that demonstrates compliance with limits in Conditions D.14.1.

(c) On and after the date the stack test results are available, the Permittee shall operate the oxidation catalyst at or above the 4-hour average temperature as observed during the latest compliant stack test.

(d) If the 4-hour average temperature falls below the above mentioned 4-hour average temperature, 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 4-hour average temperature reading below the above mentioned 4-hour average temperature is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

(e) Annual sampling and analysis of the catalyst activity (i.e., conversion efficiency) following the manufacturer's or catalyst supplier's recommended procedures. If problems are found during the catalyst activity test, the Permittee must replace the catalyst bed or take other corrective action consistent with the manufacturer's recommendations.

(1) Determine the catalyst activity level by evaluating the conversion efficiency.

(2) The catalyst conversion efficiency is evaluated and compared to typical values for fresh catalyst.

(3) An excursion is identified as a finding that the conversion efficiency is beyond the operational range of the catalyst as defined by the manufacturer.

D.14.13 NOx Continuous Emissions Monitoring (CEMS) Equipment Downtime [326 IAC 3-5-6]

(a) In the event that a breakdown of a NOx continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a NOx continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup NOx CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary NOx CEMS, the Permittee shall comply with the following:

(1) In instances of CEMS downtime, the Permittee shall report the NOx mass emissions in accordance with the procedures regulated by 40 CFR Part 75, Appendix D (Optional SO2 Emissions Data Protocol) for fuel flow meters requirements, 40 CFR Part 75, Appendix E (Optional NOx Emissions Estimation Protocol) for emission rate curve establishment, and Appendix G (Determination of CO2 Emissions). NOx mass emissions reported shall be based on the fuel-and-unit specific NOx emission rates ("load curve") established during the latest and most representative CEMS data.

(c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during operations, with at least four (4) hours between each set of readings, until a NOx CEMS is online.

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

D.14.14 Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) The Permittee shall record the output of the continuous monitoring systems (lb/hr) and shall perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(b) In the event that a breakdown of the NOx continuous emission monitoring systems (CEMS) occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

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

D.14.15 Record Keeping Requirements

(a) To document the compliance status with Conditions D.14.2, D.14.3 and D.14.4, the Permittee shall maintain monthly records in accordance with (1) and (4) below. Records maintained for (1) and (4) shall be taken as stated below and shall be complete and sufficient to establish compliance with the GHG, VOC, PM and NOx emission limits established in Conditions D.14.2, D.14.3 and D.14.4:

(1) To document the compliance status with Condition D.14.2(a), the Permittee shall maintain monthly records of the CO2e emissions.

(2) To document the compliance status with Condition D.14.2(b), the Permittee shall maintain monthly records of the CO2e emissions.

(3) To document the compliance status with Condition D.14.4(b), the Permittee shall maintain monthly records of the NOx emissions.

(4) Monthly VOC emissions from each combustion turbine (Unit 21A, Unit 21B, Unit 22A and Unit 22B) as calculated using the equation in Condition D.14.11(a).

(5) Monthly total GHGs emissions from each combustion turbine (Unit 21A, Unit 21B, Unit 22A and Unit 22B) when operating in simple cycle mode as calculated using the equation in Condition D.14.11(b).

(6) Monthly total GHGs emissions from each combustion turbine (Unit 21A, Unit 21B, Unit 22A and Unit 22B) when operating in combined cycle mode as calculated using the equation in Condition D.14.11(c).

(7) Monthly PM emissions from the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A and Unit 22B, as calculated using the equation in Condition D.14.11(d).

(b) The number of startup and shutdown events per month.

(c) The number of minutes for each startup event and each shutdown event.

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

D.14.16 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5-5(f)(1), the Permittee shall prepare and submit to IDEM, OAQ a written report for performance audits as follows:

(1) Owners or operators of emissions units required to conduct a:

(A) cylinder gas audit;
(B) relative accuracy test audit; or
(C) continuous opacity monitor calibration error audit;

on continuous emission monitors shall prepare a written report of the results of the performance audit for each calendar quarter, or for other periods required by

the department. The owner or operator shall submit quarterly reports to the department within thirty (30) calendar days after the end of each quarter for cylinder gas audits and continuous opacity monitor calibration error audits and within forty-five (45) calendar days after the completion of the test for relative accuracy test audits.

(2) The report must contain the information required by 326 IAC 3-5-5(f)(2).

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(33).

(b) Pursuant to 326 IAC 3-5-7(c)(4), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) date of downtime;
(2) time of commencement;
(3) duration of each downtime;
(4) reasons for each downtime; and
(5) nature of system repairs and adjustments.

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(33).

D.14.17 Reporting Requirements

A quarterly summary of the information to document the compliance status with Conditions D.14.2, D.14.3(d), D14.3(e), D.14.4(a) and D.14.4(b) shall be submitted not later than thirty (30) days after the end of the quarter being reported. 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(33). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

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SECTION D.15 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(p) Two (2) natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, approved in 2026 for construction, each with a rated maximum capacity of 115 MMBtu per hour, using low NOx burners, and exhausting to stacks SAUX1 and SAUX2.

[Under 40 CFR 60, Subpart Db, these units are affected facilities]
[Under 40 CFR 63, Subpart DDDDD, these units are affected sources]

(q) One (1) natural gas-fired dew point heater, identified as DPH1, approved in 2026 for construction, with a rated maximum capacity of 28 MMBtu per hour, and exhausting to stack SDPH1.

[Under 40 CFR 60, Subpart Dc, this unit is an affected facility]
[Under 40 CFR 63, Subpart DDDDD, this unit is an affected source]

(r) Two (2) 2,500 kW diesel-fired certified emergency generators, identified as EDGCC1 and EDGCC2, approved in 2026 for construction, each with a rated maximum capacity of 3,353 hp, and exhausting to stacks SEDGCC1 and SEDGCC2.

[Under 40 CFR 60, Subpart IIII, these units are affected facilities]
[Under 40 CFR 63, Subpart ZZZZ, these units are affected sources]

(s) Two (2) 244 kW diesel-fired certified emergency fire pumps, identified as FPCC1 and FPCC2, approved in 2026 for construction, each with a rated maximum capacity of 327 hp, and exhausting to stacks SFPCC1 and SFPCC2.

[Under 40 CFR 60, Subpart IIII, these units are affected facilities]
[Under 40 CFR 63, Subpart ZZZZ, these units are affected sources]

Insignificant Activities:

(j) Two (2) mechanical draft cooling towers, identified as CTH1 and CTH2, approved in 2026 for construction, each with a rated maximum circulation of 280,000 gallons of water per minute, TDS of 2,000 ppm, and total drift loss of 0.0005%.

(k) One (1) diesel storage tank, identified as TKCC1, approved in 2026 for construction, with a design storage capacity of 5,000 gallons and rated throughput of 130,000 gallons per year, and exhausting outdoors.

(l) Six (6) lube oil demister vents, identified as LOV21A, LOV21B, LOV22A, LOV22B, LOV21S, and LOV22S, approved in 2026 for construction, each with a vent flow rate of 500 cfm.

(m) High Voltage Electric Switchgear Containing Sulfur Hexafluoride (SF6), identified as CCCT - Circuit Breakers, approved in 2026 for construction.

(o) Natural gas piping components, identified as CCCT - Piping Systems, approved in 2026 for construction, including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections.

(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.15.1 VOC PSD Emission Limitations [326 IAC 2-2-3] [326 IAC 8-1-6]

(a) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the auxiliary boilers, identified as AUX1 and AUX2, as follows:

(1) VOC emissions from each auxiliary boiler AUX1 and AUX2 shall not exceed 5.5 lb/MMcf.

(2) VOC emissions from the auxiliary boilers, identified as AUX1 and AUX2, shall be controlled through the use of good combustion practices.

(b) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the emergency generators, identified as EDGCC1 and EDGCC2, as follows:

(1) VOC emissions from each emergency generators (EDGCC1 and EDGCC2) shall be controlled good combustion practices including the installation of an equipment design standard and compliance with the requirements of 40 CFR 60, Subpart IIII.

(2) NMHC + NOx emissions from each emergency generator (EDGCC1 and EDGCC2) shall not exceed 6.4 g/ kW-hr.

(c) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the emergency fire pump (FPCC1 and FPCC2), as follows:

(1) VOC emissions from each emergency fire pump (FPCC1 and FPCC2) shall be controlled good combustion practices including the installation of an equipment design standard and compliance with the requirements of 40 CFR 60, Subpart IIII.

(2) NMHC + NOx emissions from each emergency fire pump engine (FPGCC1 and FPGCC2) shall not exceed 6.4 g/ kW-hr.

(d) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the dew point heater DPH1, as follows:

(1) VOC emissions from the natural gas-fired dew point heater DPH1 shall not exceed 5.5 lb/MMcf.

(2) VOC emissions from the natural gas fired dew point heater DPH1 shall be controlled by good combustion practices.

(3) The Permittee shall only combust natural gas fuel in the dew point heater DPH1

(e) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the lube oil demister vents, identified as LOV21A, LOV21B, LOV22A, LOV22B, LOV21S, and LOV22S, as follows:

(1) VOC emissions from each of the lube oil demister vents shall be controlled through the use of demisters and good engineering design and operating practices.

(f) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the CCCT - natural gas piping system, as follows:

(1) The permittee shall implement an auditory/visual/olfactory (AVO) monitoring program for detecting leaks from the natural gas piping components installed as part of 2026 CCCT Project.

(2) AVO monitoring shall be performed in accordance with a written monitoring program.

(g) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the diesel storage tank (TKCC1), as follows:

(1) The permittee shall implement good equipment design and operating practices for the proposed diesel storage tank.

D.15.2 CO_2e PSD Emission Limitations [326 IAC 2-2-3]

(a) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the auxiliary boilers, identified as AUX1 and AUX2, as follows:

(1) CO_2e emissions from each of the auxiliary boilers AUX1 and AUX2 shall not exceed 119,438 lb/MMcf (GWPs per July 29, 2025).

(2) CO_2e emissions from each of the auxiliary boilers AUX1 and AUX2 shall be controlled through the use of natural gas fuel, implement efficient boiler design, and good combustion practices.

(b) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the emergency generators (EDGCC1 and EDGCC2), as follows:

(1) The CO_2e emissions from each emergency generator (EDGCC1 and EDGCC2) shall be controlled through the use of good combustion practices including the installation of an equipment design standard and the compliance of the 40 CFR Part 60 Subpart IIII.

(2) The CO_2e emissions from each emergency generator (EDGCC1 and EDGCC2) shall not exceed 163.6 lb/MMBtu (GWPs per July 29, 2025).

(c) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the emergency fire pump (FPCC1 and FPCC2), as follows:

(1) The CO_2e emissions from each emergency fire pump (FPCC1 and FPCC2) shall be controlled through the use of good combustion practices including the installation of an equipment design standard and the compliance of the 40 CFR Part 60 Subpart IIII.

(2) The CO_2e emissions from each emergency fire pump (FPCC1 and FPCC2) shall not exceed 163.6 lb/MMBtu (GWPs per July 29, 2025).

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(d) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the dew point heater DPH1, as follows:

(1) CO_2e emissions from the natural gas fired dew point heater DPH1 shall not exceed 119,438 lb/MMcf (GWPs per July 29, 2025).

(2) GHG emissions from the natural gas fired dew point heater DPH1 shall be controlled by good combustion practices.

(3) The Permittee shall only combust natural gas fuel in the dew point heater DPH1.

(e) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the CCCT - Circuit Breakers, as follows:

(1) The Permittee shall use a fully enclosed pressurized SF6 circuit breakers outfitted with density alarms for leak detection.

(2) The circuit breakers shall be designed to have a maximum SF6 leak rate not to exceed 0.5% per twelve (12) consecutive month period.

(f) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the CCCT - natural gas piping system, as follows:

(1) The permittee shall implement an auditory/visual/olfactory (AVO) monitoring program for detecting leaks from the natural gas piping components installed as part of 2026 CCCT Project.

(2) AVO monitoring shall be performed in accordance with a written monitoring program.

D.15.3 Particulate Emissions Limitations for Sources of Indirect Heating [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-1(f) (Particulate Emission Limitations for Sources of Indirect Heating), the particulate emissions from the auxiliary boilers (AUX1 and AUX2) and the dew point heater (DPH1) shall be limited to 0.10 pound per MMBtu heat input, each.

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SECTION E.1 TITLE IV CONDITIONS

ORIS Code: 6085

Emissions Unit Description:

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NOX burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NOX), sulfur dioxide (SO2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source]

(b) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NOX burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NOX), sulfur dioxide (SO2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility]
[Under 40 CFR Part 63, Subpart UUUUU, this is an affected source]

(c) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, and exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

[Under 40 CFR Part 60, Subpart GG these units are affected facilities]

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a rated maximum heat input capacity of 519 MMBtu per hour, each using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are intermediate load affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20,

approved in 2024 for construction, with a rated maximum heat input capacity of 2,416 MMBtu per hour, using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR 60, Subpart KKKK, this unit is an affected facility]
[Under 40 CFR 60, Subpart TTTTa, this unit is an intermediate load affected facility]
[Under 40 CFR 63, Subpart YYYY, this unit is an affected source]

(o) Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a rated maximum capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a rated maximum heat input of 987 MMBtu per hour, using dry low-NOx combustors and voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

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

Acid Rain Program

E.1.1 Acid Rain Permit [326 IAC 2-7-5(1)(C)] [326 IAC 21][40 CFR 72 through 40 CFR 78]

Pursuant to 326 IAC 21 (Acid Deposition Control), the Permittee shall comply with all provisions of the Acid Rain permit issued for this source, and any other applicable requirements contained in 40 CFR 72 through 40 CFR 78.

E.1.2 Title IV Emissions Allowances [326 IAC 2-7-5(4)] [326 IAC 21]

Emissions exceeding any allowances that the Permittee lawfully holds under the Title IV Acid Rain Program of the Clean Air Act are prohibited, subject to the following limitations:

(a) No revision of this permit shall be required for increases in emissions that are authorized by allowances acquired under the Title IV Acid Rain Program, provided that such increases do not require a permit revision under any other applicable requirement.

(b) No limit shall be placed on the number of allowances held by the Permittee. The Permittee may not use allowances as a defense to noncompliance with any other applicable requirement.

(c) Any such allowance shall be accounted for according to the procedures established in regulations promulgated under Title IV of the Clean Air Act.

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SECTION E.2 **RESERVED**

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SECTION E.3 NSPS

Emissions Unit Description:

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source]

(b) One (1) dry bottom pulverized coal-fired boiler identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility]
[Under 40 CFR Part 63, Subpart UUUUU, 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.3.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

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

(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
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

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E.3.2 Standards of Performance for Electric Utility Steam Generating Units NSPS [326 IAC 12] [40 CFR Part 60, Subpart Da]

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

(1) 40 CFR 60.40Da(a)
(2) 40 CFR 60.42Da(a)
(3) 40 CFR 60.43Da(a), (b), and (h)
(4) 40 CFR 60.44Da(a)
(5) 40 CFR 60.48Da(a), (b), (d), (e), (h), (p), and (s)
(6) 40 CFR 60.49Da(b)(1), (4), (c), (d), (e), (f)(1), (g), (h), (i), (j), (s), and (w)
(7) 40 CFR 60.50Da(a), (b)(1), (3), (c), (d), and (e)
(8) 40 CFR 60.51Da(a), (b), (c), (j), and (k)

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SECTION E.4 NSPS

Emissions Unit Description:

(d) Fuel storage and handling systems for Unit 17 and 18 boilers constructed in 1980.

(1) Rail car unloading of coal, with a multi-compartment baghouse for PM control and enclosure for ancillary dust control.

(2) Truck unloading of petroleum coke (petcoke).

(3) Coal pile unloading, coal storage pile(s), petcoke pile unloading, petcoke storage pile(s), material handling equipment, and conveyors.

(4) Transfer House with an estimated throughput of 4,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a multi-compartment baghouse for PM control. To produce petcoke blends, coal and petcoke are combined in rotary plow during transfer to conveyor.

(5) Crusher House with a designated capacity of 3,000 tons per hour, with enclosed transfer points within an enclosure for dust control, with a multi-compartment baghouse for PM control.

(6) Transfer House to tripper with an estimated throughput of 3,000 tons per hour, with enclosed transfer points within an enclosure for ancillary dust control, with a baghouse, identified as TFDC-XFR, for PM control, constructed in 2015.

(7) Two (2) tripper conveyors with an estimated combined throughput of 3,000 tons per hour with enclosure for ancillary dust control, with a baghouse, identified as TFDC-18 for PM control, constructed in 2015.

(8) Twelve (12) Fuel Silos (bunkers) with enclosure for dust control, with two (2) baghouses, identified as TFDC-17 and TFDC-18, for PM control, constructed in 2015.

[Under 40 CFR Part 60, Subpart Y this unit is an affected facility]

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

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

(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
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

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E.4.2 New Source Performance Standards of Performance for Coal Preparation and Processing Plants Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart Y]

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

(1) 40 CFR 60.250(a)&(b)
(2) 40 CFR 60.254(a)
(3) 40 CFR 60.255(a)

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SECTION E.5 NSPS

Emissions Unit Description:

(c) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NO_X control, exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), and continuous monitoring systems to measure the water to fuel ratio.

[Under 40 CFR Part 60, Subpart GG these units are affected facilities]

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

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

(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
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

E.5.2 New Source Performance Standards for Stationary Gas Turbines Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart GG]

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

(1) 40 CFR 60.330
(2) 40 CFR 60.332(a)&(f)
(3) 40 CFR 60.333
(4) 40 CFR 60.334
(5) 40 CFR 60.335

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SECTION E.6 NSPS

Emissions Unit Description:

(e) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system, constructed 2016.

[Under 40 CFR 60, Subpart IIII, this facility is considered a new affected facility]
[Under 40 CFR 63, Subpart ZZZZ, this facility is considered a new affected source]

(m) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a rated maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

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

(n) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a rated maximum capacity of 327 horsepower, and exhausting to stack FP1.

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

(r) Two (2) 2,500 kW diesel-fired certified emergency generators, identified as EDGCC1 and EDGCC2, approved in 2026 for construction, each with a rated maximum capacity of 3,353 hp, and exhausting indoors.

Under 40 CFR 60, Subpart IIII, the emergency generators EDGCC1 and EDGCC2 are considered emergency stationary compression ignition (CI) internal combustion engines (ICE) that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and with a displacement of less than 30 liters per cylinder.

Under 40 CFR 63, Subpart ZZZZ, the emergency generators EDGCC1 and EDGCC2 are considered new emergency stationary compression ignition (CI) reciprocating internal combustion engines (RICE) that commenced construction on or after December 19, 2002, located at a major source of HAP emissions.

(s) Two (2) 244 kW diesel-fired certified emergency fire pumps, identified as FPCC1 and FPCC2, approved in 2026 for construction, each with a rated maximum capacity of 327 hp, and exhausting indoors.

Under 40 CFR 60, Subpart IIII, the emergency fire pumps FPCC1 and FPCC2 are considered emergency stationary compression ignition (CI) internal combustion engines (ICE) that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and with a displacement of less than 30 liters per cylinder.

Under 40 CFR 63, Subpart ZZZZ, the emergency fire pumps FPCC1 and FPCC2 are considered new emergency stationary compression ignition (CI) reciprocating internal combustion engines (RICE) that commenced construction on or after December 19, 2002, located at a major source of HAP emissions.

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

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

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

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

E.6.2 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines NSPS [326 IAC 12] [40 CFR Part 60, Subpart IIII]

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

(a) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system

(1) 40 CFR 60.4200(a)(2)(ii)
(2) 40 CFR 60.4205(c)
(3) 40 CFR 60.4206
(4) 40 CFR 60.4207(a)
(5) 40 CFR 60.4207(b)
(6) 40 CFR 60.4209(a)
(7) 40 CFR 60.4211(a)
(8) 40 CFR 60.4211(c)
(9) 40 CFR 60.4211(f)
(10) 40 CFR 60.4211(g)(2)
(11) 40 CFR 60.4214(b)
(12) 40 CFR 60.4218
(13) Table 3 to Subpart IIII of Part 60
(14) Table 4 to Subpart IIII of Part 60
(15) Table 8 to Subpart IIII of Part 6

(b) One (1) diesel emergency generator (EDG1) and one (1) diesel emergency fire pump (FP1)

(1) 40 CFR 60.4200(a)
(2) 40 CFR 60.4205(b) and (c)
(3) 40 CFR 60.4206
(4) 40 CFR 60.4207(b)
(5) 40 CFR 60.4208
(6) 40 CFR 60.4209
(7) 40 CFR 60.4211(a), (c), and (f)
(8) 40 CFR 60.4212
(9) 40 CFR 60.4214(b) and (c)
(10) 40 CFR 60.4218
(11) 40 CFR 60.4219

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(12) Table 2 to Subpart IIII of Part 60
(13) Table 5 to Subpart IIII of Part 60
(14) Table 8 to Subpart IIII of Part 60

(c) Two (2) diesel-fired emergency generators EDGCC1 and EDGCC2

60.4200(a)(2)(i)	Am I subject to this subpart?
60.4204(b)	What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
60.4205(b)	What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
60.4206	How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?
60.4207(b)	What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?
60.4208	What is the deadline for importing or installing stationary CI ICE produced in previous model years?
60.4209	What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?
60.4211(a), (c), (f) and (g)(3)	What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?
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?
60.4214(b), (d), (g), (h), (i) and (j)	What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?
60.4218	What General Provisions and confidential information provisions apply to me?
60.4219	What definitions apply to this subpart?
Tables to Subpart IIII of Part 60	
Table 8	Applicability of General Provisions to Subpart IIII

(d) Two (2) diesel-fired emergency fire pumps FPCC1 and FPCC2

60.4200(a)(2)(ii)	Am I subject to this subpart?
60.4204(b)	What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
60.4205(c)	What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
60.4206	How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?
60.4207(b)	What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?
60.4208	What is the deadline for importing or installing stationary CI ICE produced in previous model years?
60.4209	What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?
60.4211(a), (c), (f) and (g)(2)	What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?
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?
60.4214(b), (d), (g), (h), (i) and (j)	What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?
60.4218	What General Provisions and confidential information provisions apply to

	me?
60.4219	What definitions apply to this subpart?
Tables to Subpart IIII of Part 60	
Table 8	Applicability of General Provisions to Subpart IIII

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SECTION E.7 **RESERVED**

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SECTION E.8 NESHAP

Emissions Unit Description:

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source]

(b) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility]
[Under 40 CFR Part 63, Subpart UUUUU, 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.8.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]

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

(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
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

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E.8.2 Coal- and Oil-Fired Electric Utility Steam Generating Units NESHAP [40 CFR Part 63, Subpart UUUUU] [326 IAC 20-89]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart UUUUU (included as Attachment G to the operating permit), which are incorporated by reference as 326 IAC 20-89, for the emission unit(s) listed above:

(1) 40 CFR 63.9980
(2) 40 CFR 63.9981
(3) 40 CFR 63.9982(a)(1) and (d)
(4) 40 CFR 63.9984(b), (c), and (f)
(5) 40 CFR 63.9990(a)(2) and (c)
(6) 40 CFR 63.9991(a)(1) and (b)
(7) 40 CFR 63.10000(a), (b), (c)(1), (d), (e), (f), (j), (k), and (l)
(8) 40 CFR 63.10005(a)(1), (a)(2), (b), (d)(1), (d)(3), (e), (j), and (k)
(9) 40 CFR 63.10006
(10) 40 CFR 63.10007(a)(1), (b), (e)(2), (f), and (g)
(11) 40 CFR 63.10009
(12) 40 CFR 63.10010(a)(1), (b), (d), (f), (g), and (i)
(13) 40 CFR 63.10011(a), (c), (e), (f), and (g)
(14) 40 CFR 63.10020(a), (b), (c), and (d)
(15) 40 CFR 63.10021(a), (b), (e), (f), (g), and (h)
(16) 40 CFR 63.10022
(17) 40 CFR 63.10030(a), (b), (d) and (e)
(18) 40 CFR 63.10031(a)(1), (a)(3), (a)(5), (b), (c)(1), (c)(2), (c)(3), (c)(4), (c)(8), (c)(9), (c)(10), (d), (e), (f), (g), and (j)
(19) 40 CFR 63.10032(a), (b), (c), (d)(1), (f)(1), (g), (h), and (i)
(20) 40 CFR 63.10033
(21) 40 CFR 63.10040
(22) 40 CFR 63.10041
(23) 40 CFR 63.10042
(24) Table 2 Item 2 to Subpart UUUUU of Part 63
(25) Table 3 Item 1, 3, and 4 to Subpart UUUUU of Part 63
(26) Table 5 Item 4 to Subpart UUUUU of Part 63
(27) Table 7 Item 4, 5, 6, and 7 to Subpart UUUUU of Part 63
(28) Table 8 to Subpart UUUUU of Part 63
(29) Table 9 to Subpart UUUUU of Part 63
(30) Appendix A to Subpart UUUUU of Part 63
(29) Appendix C to Subpart UUUUU of Part 63
(30) Appendix E to Subpart UUUUU of Part 63

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SECTION E.9 NESHAP

Emissions Unit Description:

(e) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system, constructed 2016.

[Under 40 CFR 60, Subpart IIII, this facility is considered a new affected facility]
[Under 40 CFR 63, Subpart ZZZZ, this facility is considered a new affected source]

(m) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a rated maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

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

(n) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a rated maximum capacity of 327 horsepower, and exhausting to stack FP1.

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

(r) Two (2) 2,500 kW diesel-fired certified emergency generators, identified as EDGCC1 and EDGCC2, approved in 2026 for construction, each with a rated maximum capacity of 3,353 hp, and exhausting indoors.

Under 40 CFR 60, Subpart IIII, the emergency generators EDGCC1 and EDGCC2 are considered emergency stationary compression ignition (CI) internal combustion engines (ICE) that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and with a displacement of less than 30 liters per cylinder.

Under 40 CFR 63, Subpart ZZZZ, the emergency generators EDGCC1 and EDGCC2 are considered new emergency stationary compression ignition (CI) reciprocating internal combustion engines (RICE) that commenced construction on or after December 19, 2002, located at a major source of HAP emissions.

(s) Two (2) 244 kW diesel-fired certified emergency fire pumps, identified as FPCC1 and FPCC2, approved in 2026 for construction, each with a rated maximum capacity of 327 hp, and exhausting indoors.

Under 40 CFR 60, Subpart IIII, the emergency fire pumps FPCC1 and FPCC2 are considered emergency stationary compression ignition (CI) internal combustion engines (ICE) that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and with a displacement of less than 30 liters per cylinder.

Under 40 CFR 63, Subpart ZZZZ, the emergency fire pumps FPCC1 and FPCC2 are considered new emergency stationary compression ignition (CI) reciprocating internal combustion engines (RICE) that commenced construction on or after December 19, 2002, located at a major source of HAP emissions.

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

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

E.9.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]

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

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

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

E.9.2 Stationary Reciprocating Internal Combustion Engines NESHAP [40 CFR Part 63, Subpart ZZZZ] [326 IAC 20-82]

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

(a) One (1) diesel-fired, compression-ignited, 350 horsepower engine for a stationary fire pump system

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

(b) One (1) diesel emergency generator (EDG1) and two (2) diesel-fired emergency generators (EDGCC1 and EDGCC2)

63.6580	What is the purpose of subpart ZZZZ?
63.6585(b)	Am I subject to this subpart?
63.6590(a)(2)(i) and (b)(1)(i)	What parts of my plant does this subpart cover?

(c) One (1) diesel emergency fire pump (FP1) and two (2) diesel-fired emergency fire pumps (FPCC1 and FPCC2)

63.6580	What is the purpose of subpart ZZZZ?
63.6585(b)	Am I subject to this subpart?
63.6590(a)(2)(i) and (c)(7)	What parts of my plant does this subpart cover?

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SECTION E.10 NSPS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a rated maximum heat input capacity of 519 MMBtu per hour, each using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are intermediate load affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a rated maximum heat input capacity of 2,416 MMBtu per hour, using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR 60, Subpart KKKK, this unit is an affected facility]
[Under 40 CFR 60, Subpart TTTTa, this unit is an intermediate load affected facility]
[Under 40 CFR 63, Subpart YYYY, this unit is an affected source]

(o) Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a rated maximum capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a rated maximum heat input of 987 MMBtu per hour, using dry low-NOx combustors and voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

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

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

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(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
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

E.10.2 New Source Performance Standards for Stationary Combustion Turbines that Commenced Construction, Modification or Reconstruction After February 18, 2005, and on or Before December 13, 2024 NSPS [326 IAC 12] [40 CFR Part 60, Subpart KKKK]

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

60.4305	Does this subpart apply to my stationary combustion turbine?
60.4315	What pollutants are regulated by this subpart?
60.4320(a)	What emission limits must I meet for nitrogen oxides (NOX)?
60.4330(a)	What emission limits must I meet for sulfur dioxide (SO2?
60.4333	What are my general requirements for complying with this subpart?
60.4340	How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?
60.4345	What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?
60.4350	How do I use data from the continuous emission monitoring equipment to identify excess emissions?
60.4355	How do I establish and document a proper parameter monitoring plan?
60.4365	How can I be exempted from monitoring the total sulfur content of the fuel?
60.4370(b)	How often must I determine the sulfur content of the fuel?
60.4375	What reports must I submit?
60.4380	How are excess emissions and monitor downtime defined for NOX?
60.4395	When must I submit my reports?
60.4400	How do I conduct the initial and subsequent performance tests, regarding NOX?
60.4405	How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS?
60.4410	How do I establish a valid parameter range if I have chosen to continuously monitor parameters?
60.4420	What definitions apply to this subpart?
Tables to Subpart KKKK of Part 60	
Table 1	Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

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SECTION E.11 NSPS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a rated maximum heat input capacity of 519 MMBtu per hour, each using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are intermediate load affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a rated maximum heat input capacity of 2,416 MMBtu per hour, using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR 60, Subpart KKKK, this unit is an affected facility]
[Under 40 CFR 60, Subpart TTTTa, this unit is an intermediate load affected facility]
[Under 40 CFR 63, Subpart YYYY, this unit is an affected source]

(o) Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a rated maximum capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a rated maximum heat input of 987 MMBtu per hour, using dry low-NOx combustors and voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

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

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

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(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
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

E.11.2 New Source Performance Standards for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart TTTTa]

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

60.5509a(a)	Am I subject to this subpart?
60.5515a	Which pollutants are regulated by this subpart?
60.5520a	What CO_2 emissions standard must I meet?
60.5525a	What are my general requirements for complying with this subpart?
60.5535a	How do I monitor and collect data to demonstrate compliance?
60.5550a	What notifications must I submit and when?
60.5555a	What reports must I submit and when?
60.5560a	What records must I maintain?
60.5565a	In what form and how long must I keep my records?
60.5570a	What parts of the general provisions apply to my affected EGU?
60.5575a	Who implements and enforces this subpart?
60.5580a	What definitions apply to this subpart?
Tables to Subpart TTTTa of Part 60	
Table 1	CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After May 23, 2023 (Gross or Net Energy Output-Based Standards Applicable as Approved by the Administrator)
Table 3	Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTTa

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SECTION E.12 NSPS

Emissions Unit Description:

(p) Two (2) natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, approved in 2026 for construction, each with a rated maximum capacity of 115 MMBtu per hour, using low NOx burners, and exhausting to stacks SAUX1 and SAUX2.

[Under 40 CFR 60, Subpart Db, these units are affected facilities]
[Under 40 CFR 63, Subpart DDDDD, these units are affected sources]

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

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

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

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

E.12.2 New Source Performance Standards for Industrial Commercial Institutional Steam Generating Units NSPS [326 IAC 12] [40 CFR Part 60, Subpart Db]

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

60.40b(a)	Applicability and delegation of authority.
60.41b	Definitions.
60.42b(k)(2)	Standard for sulfur dioxide (SO2).
60.44b(l)(1)	Standard for nitrogen oxides (NOx).
60.46b(e)(1)-(4)	Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.
60.48b(b), (c), (e), (f) and (g)	Emission monitoring for particulate matter and nitrogen oxides.
60.49b(a)-(c), (d), (g), (h), (i), (o), (r)(1), (v) and (w)	Reporting and recordkeeping requirements.

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SECTION E.13 NSPS

Emissions Unit Description:

(q) One (1) natural gas-fired dew point heater, identified as DPH1, approved in 2026 for construction, with a rated maximum capacity of 28 MMBtu per hour, and exhausting to stack SDPH1.

[Under 40 CFR 60, Subpart Dc, this unit is an affected facility]
[Under 40 CFR 63, Subpart DDDDD, this unit 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.13.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

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

(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
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

E.13.2 New Source Performance Standards for Small Industrial Commercial Institutional Steam Generating Units NSPS [326 IAC 12] [40 CFR Part 60, Subpart Dc]

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

60.40c	Applicability and delegation of authority.
60.41c	Definitions.
60.48c(a)	Reporting and recordkeeping requirements.

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SECTION E.14 NESHAP

Emissions Unit Description:

(p) Two (2) natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, approved in 2026 for construction, each with a rated maximum capacity of 115 MMBtu per hour, using low NOx burners, and exhausting to stacks SAUX1 and SAUX2.

[Under 40 CFR 60, Subpart Db, these units are affected facilities]
[Under 40 CFR 63, Subpart DDDDD, these units are affected sources]

(q) One (1) natural gas-fired dew point heater, identified as DPH1, approved in 2026 for construction, with a rated maximum capacity of 28 MMBtu per hour, and exhausting to stack SDPH1.

[Under 40 CFR 60, Subpart Dc, this unit is an affected facility]
[Under 40 CFR 63, Subpart DDDDD, this unit 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.14.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-95, for the emission unit(s) 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
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

E.14.2 Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP [40 CFR Part 63, Subpart DDDDD] [326 IAC 20-95]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart DDDDD (included as Attachment M to the operating permit), which are incorporated by reference as 326 IAC 20-95, for the emission unit(s) listed above:

63.7480	What is the purpose of this subpart?
63.7485	Am I subject to this subpart?
63.7490(a)(2) and (b)	What is the affected source of this subpart?
63.7495(a)	When do I have to comply with this subpart?
63.7499(l)	What are the subcategories of boilers and process heaters?
63.7500	What emission limitations, work practice standards, and operating limits must I meet?
63.7505(a)	What are my general requirements for complying with this subpart?
63.7510	What are my initial compliance requirements and by what date must I

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	conduct them?
63.7515	When must I conduct subsequent performance tests, fuel analyses, or tune-ups?
63.7545	What notifications must I submit and when?
63.7550	What reports must I submit and when?
63.7555	What records must I keep?
63.7560	In what form and how long must I keep my records?
63.7565	What parts of the General Provisions apply to me?
63.7570	Who implements and enforces this subpart?
63.7575	What definitions apply to this subpart?
Tables to Subpart DDDDD of Part 63	
Table 1	Emission Limits for New or Reconstructed Boilers and Process Heaters [c]
Table 3	Work Practice Standards
Table 9	Reporting Requirements
Table 10	Applicability of General Provisions to Subpart DDDDD
Table 14	Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters [c]

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SECTION E.15 NESHAP

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a rated maximum heat input capacity of 519 MMBtu per hour, each using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are intermediate load affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected source]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a rated maximum heat input capacity of 2,416 MMBtu per hour, using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR 60, Subpart KKKK, this unit is an affected facility]
[Under 40 CFR 60, Subpart TTTTa, this unit is an intermediate load affected facility]
[Under 40 CFR 63, Subpart YYYY, this unit is an affected source]

(o) Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a rated maximum capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a rated maximum heat input of 987 MMBtu per hour, using dry low-NOx combustors and voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

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

(a) Pursuant to 40 CFR 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-90, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart YYYY.

(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
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

E.15.2 Stationary Combustion Turbines NESHAP [40 CFR Part 63, Subpart YYYY] [326 IAC 20-90]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart YYYY (included as Attachment N to the operating permit), which are incorporated by reference as 326 IAC 20-90, for the emission unit(s) listed above:

63.6080	What is the purpose of subpart YYYY?
63.6085	Am I subject to this subpart?
63.6090	What parts of my plant does this subpart cover?
63.6092	Are duct burners and waste heat recovery units covered by subpart YYYY?
63.6095	When do I have to comply with this subpart?
63.6100	What emission and operating limitations must I meet?
63.6105(c)	What are my general requirements for complying with this subpart?
63.6110	By what date must I conduct the initial performance tests or other initial compliance demonstrations?
63.6115	When must I conduct subsequent performance tests?
63.6120	What performance tests and other procedures must I use?
63.6125(a)	What are my monitor installation, operation, and maintenance requirements?
63.6130	How do I demonstrate initial compliance with the emission and operating limitations?
63.6135	How do I monitor and collect data to demonstrate continuous compliance?
63.6140	How do I demonstrate continuous compliance with the emission and operating limitations?
63.6145	What notifications must I submit and when?
63.6150	What reports must I submit and when?
63.6155	What records must I keep?
63.6160	In what form and how long must I keep my records?
63.6165	What parts of the General Provisions apply to me?
63.6170	Who implements and enforces this subpart?
63.6175	What definitions apply to this subpart?
Tables to Subpart YYYY of Part 63	
Table 1	Emission Limitations
Table 2	Operating Limitations
Table 3	Requirements for Performance Tests and Initial Compliance Demonstrations
Table 4	Initial Compliance With Emission Limitations
Table 5	Continuous Compliance With Operating Limitations
Table 6	Requirements for Reports
Table 7	Applicability of General Provisions to Subpart YYYY

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SECTION F EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

Entire Source

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

Provisions of Northern Indiana Public Service Company LLC Consent Decree Applicable to R.M. Schahfer Generating Station

F.1 Consent Decree [*United States and the State of Indiana v. Northern Indiana Public Service Co.*, 2:11-cv-00016-JVB-APR (N.D. Ind. July 22, 2011), paragraph 169] [326 IAC 2-7-6(3)]

This source is subject to certain conditions, requirements and limitations set forth in the consent decree entered into by and among the United States, the State of Indiana, and the Permittee in *United States and the State of Indiana v. Northern Indiana Public Service Co.*, 2:11-cv-00016-JVB-APR (N.D. Ind. July 22, 2011) (herein referred to as the "Decree"). Pursuant to paragraph 169 of the Decree, those paragraphs and tables of the Decree listed in Attachment A of this permit are incorporated by reference into this permit and are applicable requirements under this permit. Subject to the terms and conditions of this Section F.1, the Permittee shall comply with the paragraphs and tables of the Decree that are listed in Attachment A of this permit. A copy of the Decree is attached to this permit as Attachment B. However, only those specific paragraphs and tables of the Decree that are included in Attachment A of this permit and incorporated by reference pursuant to this Section F.1, are applicable requirements enforceable through this permit.

Each paragraph and table listed in Attachment A of this permit is incorporated by reference in its entirety, including any and all paragraphs, conditions, requirements and/or limitations of the Decree explicitly referenced in such paragraphs or tables. However, the Permittee's obligations under this permit to comply with the conditions, requirements and limitations incorporated by reference in the paragraphs and tables listed in Attachment A of this permit shall be limited to those conditions, requirements and limitations applicable to, and only to the extent applicable to, the R.M. Schahfer Station while this permit is in effect. For clarity, such applicable conditions, requirements and limitations shall, subject to the subsequent paragraph, include the annual system tonnage limitations applicable to the Northern Indiana Public Service Company LLC System (as that term is defined under paragraph 36 of the Decree) as a whole as provided under Table 4 and Table 6 of the Decree as listed in Attachment A hereto.

In accordance with paragraph 169 of the Decree, any noncompliance with an annual system tonnage limitation incorporated by reference pursuant to this Section F.1 and Attachment A shall constitute a single violation for the Northern Indiana Public Service Company LLC System (as that term is defined under paragraph 36 of the Decree) as a whole and does not create a separate violation or violations for each unit or source within the Northern Indiana Public Service Company LLC System. Compliance with the paragraphs and tables listed in Attachment A of this permit shall be determined exclusively by reference to the conditions, requirements, and limitations of the Decree. Whenever any conflict or inconsistency arises between the Decree and this permit, the terms and conditions of the Decree control.

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SECTION G **RESERVED**

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SECTION H TR NO_X Annual Trading Program, TR NO_X Ozone Season Group 2 Trading Program, and TR SO_2 Group 1 Trading Program Requirements (40 CFR 97.406), (40 CFR 97.806), (40 CFR 97.606)

ORIS Code: 994

Transport Rule (TR):

(a) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 17, constructed in 1980 and commercial operation begun in 1983, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 17. Unit 17 is equipped with continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 17 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da, this unit is an affected facility]
[Under 40 CFR Part 63, Subpart UUUUU, this unit is an affected source]

(b) One (1) dry bottom pulverized coal-fired boiler, identified as Unit 18, constructed in 1980 and commercial operation begun in 1986, with a design heat input capacity of 3,967 million Btu per hour (MMBtu/hr) based on 30-day averages from coal sampling, with low NO_X burners, combusting No. 2 fuel oil and/or natural gas for ignition and as supplemental fuels, using an electrostatic precipitator (ESP) for control of particulate matter, an Activated Carbon Injection (ACI) System for mercury control, and exhausting through a limestone-based flue gas desulfurization system to stack 18. Unit 18 has continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). Unit 18 has been approved to fire blends of coal and petroleum coke.

[Under 40 CFR Part 60, Subpart Da this facility is an affected facility]
[Under 40 CFR Part 63, Subpart UUUUU, this is an affected source]

(c) Two (2) natural gas-fired combustion turbines, identified as 16A and 16B, constructed in 1979, each with a design heat input capacity of 1,450 million Btu per hour (MMBtu/hr), each using water injection as needed for NOX control, exhausting to stacks 16A and 16B, respectively. Units 16A and 16B have continuous emissions monitoring systems (CEMS) for monitoring nitrogen oxides (NOX), and continuous monitoring systems to measure the water to fuel ratio.

[Under 40 CFR Part 60, Subpart GG these units are affected facilities]

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a rated maximum heat input capacity of 519 MMBtu per hour, each using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are intermediate load affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

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(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a rated maximum heat input capacity of 2,416 MMBtu per hour, using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR 60, Subpart KKKK, this unit is an affected facility]
[Under 40 CFR 60, Subpart TTTTa, this unit is an intermediate load affected facility]
[Under 40 CFR 63, Subpart YYYY, this unit is an affected source]

(o) Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a rated maximum capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a rated maximum heat input of 987 MMBtu per hour, using dry low-NOx combustors and voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

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

H.1 Designated representative requirements

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with the following:

40 CFR 97 Subpart AAAAA - CSAPR NOx Annual Trading Program	
97.413	Authorization of designated representative and alternate designated representative.
97.414	Responsibilities of designated representative and alternate designated representative.
97.415	Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.
97.416	Certificate of representation.
97.417	Objections concerning designated representative and alternate designated representative.
97.418	Delegation by designated representative and alternate designated representative.

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40 CFR 97 Subpart EEEEE - CSAPR NOX Ozone Season Group 2 Trading Program	
97.813	Authorization of designated representative and alternate designated representative.
97.814	Responsibilities of designated representative and alternate designated representative.
97.815	Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.
97.816	Certificate of representation.
97.817	Objections concerning designated representative and alternate designated representative.
97.818	Delegation by designated representative and alternate designated representative.
40 CFR 97 Subpart CCCCC - CSAPR SO2 Group 1 Trading Program	
97.613	Authorization of designated representative and alternate designated representative.
97.614	Responsibilities of designated representative and alternate designated representative.
97.615	Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.
97.616	Certificate of representation.
97.617	Objections concerning designated representative and alternate designated representative.
97.618	Delegation by designated representative and alternate designated representative.

H.2 Emissions monitoring, reporting, and recordkeeping requirements

(1) The owners and operators, and the designated representative, of each TR NO_X Annual source, TR NOx Ozone Season Group 2 source, and TR SO2 Group 1 source, and each TR NO_X Annual unit at the source, TR NOx Ozone Season Group 2 unit at the source, and TR SO2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430, 40 CFR 97.830, and 40 CFR 97.630 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431, 97.831, and 97.631 (initial monitoring system certification and recertification procedures), 97.432, 97.832, and 97.632 (monitoring system out-of-control periods), 97.433, 97.833, and 97.633 (notifications concerning monitoring), 97.434, 97.834, and 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435, 97.835, and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of TR NO_X Annual allowances under 326 IAC 24-5 and to determine compliance with the TR NO_X Annual emissions limitation and assurance provisions under Condition H.3 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and

rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(3) The emissions data determined in accordance with 40 CFR 97.830 through 97.835 shall be used to calculate allocations of TR NO_X Ozone Season Group 2 allowances under 40 CFR 97.811(a)(2) and (b) and 97.812 and to determine compliance with the TR NO_X Ozone Season Group 2 emissions limitation and assurance provisions under Condition H.4 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(4) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of TR SO_2 Group 1 allowances 326 IAC 24-7 and to determine compliance with the TR SO_2 Group 1 emissions limitation and assurance provisions under Condition H.5 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

H.3 NOX annual emissions requirements

(1) TR NO_X Annual emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall hold, in the source's compliance account, TR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Annual units at the source.

(ii). If total NO_X emissions during a control period in a given year from the TR NO_X Annual units at a TR NO_X Annual source are in excess of the TR NO_X Annual emissions limitation set forth in Condition H.3(1)(i) above, then:

(A). The owners and operators of the source and each TR NO_X Annual unit at the source shall hold the TR NO_X Annual allowances required for deduction under 40 CFR 97.424(d); and

(B). The owners and operators of the source and each TR NO_X Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(2) TR NO_X Annual assurance provisions.

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(i). If total NO_X emissions during a control period in a given year from all TR NO_X Annual units at TR NO_X Annual sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying— (A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the TR NO_X Annual allowances required under Condition H.3(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the State during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the state NO_X Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart AAAAA or of the Clean Air Act if total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the State during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the TR NO_X Annual units at TR NO_X Annual sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold TR NO_X Annual allowances for a control period in a given year in accordance with Condition H.3(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each TR NO_X Annual allowance that the owners and operators fail to hold for such control period in accordance with Condition H.3(2)(i) through (iii)

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above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(3) Compliance periods.

(i). A TR NO_X Annual unit shall be subject to the requirements under Condition H.3(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(ii). A TR NO_X Annual unit shall be subject to the requirements under Condition H.3(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A TR NO_X Annual allowance held for compliance with the requirements under Condition H.3(1)(i) above for a control period in a given year must be a TR NO_X Annual allowance that was allocated for such control period or a control period in a prior year.

(ii). A TR NO_X Annual allowance held for compliance with the requirements under Condition H.3(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR NO_X Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR NO_X Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart AAAAA.

(6) Limited authorization. A TR NO_X Annual allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the TR NO_X Annual Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR NO_X Annual allowance does not constitute a property right.

H.4 NOx ozone season Group 2 requirements

(1) TR NO_X Ozone Season Group 2 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_X Ozone Season Group 2 source and each TR NO_X Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, TR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.824(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Ozone Season Group 2 units at the source.

(ii). If total NO_X emissions during a control period in a given year from the TR NO_X Ozone Season Group 2 units at a TR NO_X Ozone Season Group 2 source are in excess of the TR NO_X Ozone Season Group 2 emissions limitation set forth in Condition H.4(1)(i) above, then:

(A). The owners and operators of the source and each TR NO_X Ozone Season Group 2 unit at the source shall hold the TR NO_X Ozone Season Group 2 allowances required for deduction under 40 CFR 97.~~5~~824(d); and

(B). The owners and operators of the source and each TR NO_X Ozone Season Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart EEEEE and the Clean Air Act.

(2) TR NO_X Ozone Season Group 2 assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all TR NO_X Ozone Season Group 2 units at TR NO_X Ozone Season Group 2 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.825(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions

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exceeds the respective common designated representative's assurance level; and

(B). The amount by which total NO_X emissions from all TR NO_X Ozone Season Group 2 units at TR NO_X Ozone Season Group 2 sources in the state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the TR NO_X Ozone Season Group 2 allowances required under Condition H.4(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NO_X emissions from all TR NO_X Ozone Season Group 2 units at TR NO_X Ozone Season Group 2 sources in the state during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season Group 2 trading budget under 40 CFR 97.810(a) and the state's variability limit under 40 CFR 97.810(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart EEEEE or of the Clean Air Act if total NO_X emissions from all TR NO_X Ozone Season Group 2 units at TR NO_X Ozone Season Group 2 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the TR NO_X Ozone Season Group 2 units at TR NO_X Ozone Season Group 2 sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold TR NO_X Ozone Season Group 2 allowances for a control period in a given year in accordance with Condition H.4(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each TR NOX Ozone Season Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (d)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart EEEEE and the Clean Air Act.

(3) Compliance Periods.

(i). A TR NOx Ozone Season Group 2 unit shall be subject to the requirements under Condition H.4(1) above for the control period starting on the later of May 1, 2015 or the deadline for meeting the unit's monitor certificate requirements under 40 CFR 97.830(b) and for each control period thereafter.

(ii). A TR NOx Ozone Season Group 2 unit shall be subject to the requirements under Condition H.4(2) above for the control period starting on the later of May 1,

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2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A TR NOx Ozone Season Group 2 allowance held for compliance with the requirements under Condition H.4(1)(i) above for a control period in a given year must be a TR NOx Ozone Season Group 2 allowance that was allocated for such control period or a control period in a prior year.

(ii). A TR NOx Ozone Season Group 2 allowance held for compliance with the requirements under Condition H.4(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR NOx Ozone Season allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowances Management System Requirements.

(i). Each TR NOx Ozone Season Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart EEEEE.

(6) Limited Authorization.

(i). A TR NOx Ozone Season Group 2 allowance is a limited authorization to emit one ton of NOx during the control period in one year. Such authorization is limited in its use and duration as follows:

(A). Such authorization shall only be used in accordance with the TR NOx Ozone Season Group 2 Trading Program; and

(B). Notwithstanding any other provision of 40 CFR Part 97, Subpart EEEEE, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property Right.

(i). A TR NOx Ozone Season Group 2 allowance does not constitute a property right.

H.5 SO_2 emissions requirements

(1) TR SO_2 Group 1 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO_2 Group 1 source and each TR SO2 Group 1 unit at the source shall hold, in the source's compliance account, TR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR

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97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all TR SO_2 Group 1 units at the source.

(ii). If total SO_2 emissions during a control period in a given year from the TR SO_2 Group 1 units at a TR SO_2 Group 1 source are in excess of the TR SO_2 Group 1 emissions limitation set forth in Condition H.5(1)(i) above, then:

(A). The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall hold the TR SO_2 Group 1 allowances required for deduction under 40 CFR 97.624(d); and

(B). The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(2) TR SO_2 Group 1 assurance provisions

(i). If total SO_2 emissions during a control period in a given year from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such SO_2 emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the TR SO_2 Group 1 allowances required under Condition H.5(2)(i) above, as of midnight of November 1 (if it is a business

day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state during a control period in a given year exceed the state assurance level if such total SO_2 emissions exceed the sum, for such control period, of the state SO_2 Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart CCCCC or of the Clean Air Act if total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total SO_2 emissions from the TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold TR SO_2 Group 1 allowances for a control period in a given year in accordance with Condition H.5(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each TR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with Condition H.5(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(3) Compliance periods.

(i) A TR SO_2 Group 1 unit shall be subject to the requirements under Condition H.5(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(ii) A TR SO_2 Group 1 unit shall be subject to the requirements under Condition H.5(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i) A TR SO_2 Group 1 allowance held for compliance with the requirements under Condition H.5(1)(i) above for a control period in a given year must be a TR SO_2 Group 1 allowance that was allocated for such control period or a control period in a prior year.

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(ii) A TR SO_2 Group 1 allowance held for compliance with the requirements under Condition H.5(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR SO_2 Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart CCCCC.

(6) Limited authorization. A TR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the TR SO_2 Group 1 Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR part 97, subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR SO_2 Group 1 allowance does not constitute a property right.

H.6 Title V Permit Revision Requirements

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_X Annual allowances in accordance with 40 CFR part 97, subpart AAAAA, TR NO_X Ozone Season Group 2 allowances in accordance with 40 CFR part 97, subpart EEEEE, and TR SO_2 Group 1 allowances in accordance with 40 CFR part 97, subpart CCCCC.

(2) This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, 40 CFR 97.830 through 97.835, and 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2), 40 CFR 97.806(d)(2), and 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

H.7 Additional recordkeeping and reporting requirements

(1) Unless otherwise provided, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit, TR NO_X Ozone Season Group 2 source and each TR NO_X Ozone Season Group 2 unit, and TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is

created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.416, 40 CFR 97.816, and 40 CFR 97.616 for the designated representative for the source and each TR NO_X Annual unit, TR NOx Ozone Season Group 2 unit, and TR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416, 40 CFR 97.816, and 40 CFR 97.616 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart AAAAA, 40 CFR part 97, subpart EEEEE, and 40 CFR part 97, subpart CCCCC.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NO_X Annual Trading Program, TR NO_X Ozone Season Group 2 Trading Program, and TR SO_2 Group 1 Trading Program.

(2) The designated representative of a TR NO_X Annual source and each TR NO_X Annual unit, a TR NO_X Ozone Season Group 2 source and each TR NO_X Ozone Season Group 2 unit, and a TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall make all submissions required under the TR NO_X Annual Trading Program, TR NO_X Ozone Season Group 2 Trading Program, and TR SO_2 Group 1 Trading Program, except as provided in 40 CFR 97.418, 40 CFR 97.818, and 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

H.8 Liability

(1) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual source or the designated representative of a TR NO_X Annual source shall also apply to the owners and operators of such source and of the TR NO_X Annual units at the source.

(2) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual unit or the designated representative of a TR NO_X Annual unit shall also apply to the owners and operators of such unit.

(3) Any provision of the TR NO_X Ozone Season Group 2 Trading Program that applies to a TR NO_X Ozone Season Group 2 source or the designated representative of a TR NO_X Ozone Season Group 2 source shall also apply to the owners and operators of such source and of the TR NO_X Ozone Season Group 2 units at the source.

(4) Any provision of the TR NO_X Ozone Season Group 2 Trading Program that applies to a TR NO_X Ozone Season Group 2 unit or the designated representative of a TR NO_X Ozone Season Group 2 unit shall also apply to the owners and operators of such unit.

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(5) Any provision of the TR SO_2 Group 1 Trading Program that applies to a TR SO_2 Group 1 source or the designated representative of a TR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the TR SO_2 Group 1 units at the source.

(6) Any provision of the TR SO_2 Group 1 Trading Program that applies to a TR SO_2 Group 1 unit or the designated representative of a TR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

H.9 Effect on other authorities

No provision of the TR NO_X Annual Trading Program or exemption under 40 CFR 97.405, TR NO_X Ozone Season Group 2 Trading Program or exemption under 40 CFR 97.805, and TR SO_2 Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_X Annual source or TR NO_X Annual unit, TR NO_X Ozone Season Group 2 source or TR NO_X Ozone Season Group 2 unit, and TR SO_2 Group 1 source or TR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

H.10 Description of TR Monitoring Provisions

The TR subject unit(s) and the unit-specific monitoring provisions at this source are identified in the following table(s). These units are subject to the requirements for the TR NOx Annual Trading Program and TR NOx Ozone Season Group 2 Trading Program and TR SO2 Group 1 Trading Program.

Unit ID: Unit 17 and Unit 18					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	X	-------	-------	-------	-------
NO_X	X	-------	-------	-------	-------
Heat input	X	-------	-------	-------	-------

Unit ID: 16A and 16B					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E

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Unit ID: 16A and 16B					
SO_2	-------	X	-------	-------	-------
NO_X	X	-------	-------	-------	-------
Heat input	-------	X	-------	-------	-------

Unit ID: 19A, 16B, 19C, and Unit 20					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	-------	X	-------	-------	-------
NO_X	X	-------	-------	-------	-------
Heat input	-------	X	-------	-------	-------

Unit ID: 21A, 21B, 22A, and 22B					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2	-------	X	-------	-------	-------
NO_X	X	-------	-------	-------	-------
Heat input	-------	X	-------	-------	-------

(1) The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (TR NOX Annual Trading Program), 97.830 through 97.835 (TR NOx Ozone Season Group 2 Trading Program), and 97.630 through 97.635 (TR SO2 Group 1 Trading Program), as applicable. The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable TR trading programs.

(2) Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

(3) Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program), 97.835 (TR NOx Ozone Season Group 2 Trading Program), and 97.635 (TR SO_2 Group 1 Trading Program), as applicable. The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

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(4) Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program), 97.830 through 97.834 (TR NOx Ozone Season Group 2 Trading Program), and 97.630 through 97.634 (TR SO_2 Group 1 Trading Program), as applicable, must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program), 97.835 (TR NOx Ozone Season Group 2 Trading Program), and 97.635 (TR SO_2 Group 1 Trading Program), as applicable. The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(5) The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program), 97.830 through 97.834 (TR NOx Ozone Season Group 2 Trading Program), and 97.630 through 97.634 (TR SO_2 Group 1 Trading Program), as applicable, and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

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

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008

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

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☐ Test Result (specify) _____

☐ Report (specify) _____

☐ Notification (specify) _____

☐ Affidavit (specify) _____

☐ Other (specify) _____

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

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MALFUNCTION REPORT

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
FAX NUMBER: (317) 233-6865
EMAIL: AirCompl@idem.in.gov

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Permit No.: T 073-45762-00008

For any malfunction lasting one (1) hour or longer, the Permittee must submit this form to the Office of Air Quality (OAQ), within four (4) daytime business hours of malfunction start.

If any of the following are not applicable, mark N/A. This form consists of two (2) pages.

This malfunction resulted in a violation of the following Indiana Administrative Code, permit condition, and/or permit limit and meets the definition of “malfunction” as listed on reverse side (e.g., 326 IAC 5-1, Permit Condition D.1.1, 40 CFR 60.62, etc.):

Describe affected facility/equipment/operation (e.g., Coating Line #2, Boiler D, Diesel engine, No. 3 smelter, etc.):	
Control equipment (e.g., Baghouse B4, Thermal oxidizer for Paint Line #1, etc.):	
Description of the malfunction and cause:	
When the malfunction started:	Date (MM/DD/YYYY):
	Time (HH:MM):
When the malfunction was corrected or is expected to be corrected:	Date (MM/DD/YYYY):
	Time (HH:MM):

Type of pollutant(s) emitted (e.g., PM, PM10, PM2.5, VOC, etc.):
Estimated amount of pollutant(s) emitted during malfunction (e.g., VOC at 35 lbs/hr, 5 tons of PM, etc.):
Describe the corrective actions and interim control measures taken to minimize emissions (e.g., shut coating line down, isolated failing baghouse compartment, idled furnace operations until repairs completed, etc.):

Form completed by: _____

Title/position: _____

Signature:_____

Date:_____

Phone: _____

Email: _____

326 IAC 1-6-1 Applicability of rule

Sec. 1. This rule applies to the owner or operator of any facility required to obtain a permit under 326 IAC 2-5.1, 326 IAC 2-6.1, 326 IAC 2-7, or 326 IAC 2-8.

326 IAC 1-2-39 "Malfunction" definition

Sec. 39. Any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner.

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

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Unit 17 and Unit 18, and their associated cooling towers
Parameter: Combined PM Emissions
Limit: Shall not exceed 91.0 tons 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
	Combined PM Emissions (tons)	*Combined PM Emissions (tons)*	*Combined PM Emissions (tons)*
	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:_____

DRAFT

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

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Unit 17 and Unit 18, and their associated cooling towers
Parameter: Combined PM10 Emissions
Limit: Shall not exceed 345.0 tons 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
	Combined PM10 Emissions (tons)	*Combined PM10 Emissions (tons)*	*Combined PM10 Emissions (tons)*
	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:_____

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

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Unit 17 and Unit 18, and their associated cooling towers
Parameter: Combined PM2.5 Emissions
Limit: Shall not exceed 292.0 tons 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
	Combined PM2.5 Emissions (tons)	*Combined PM2.5 Emissions (tons)*	*Combined PM2.5 Emissions (tons)*
	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:_____

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

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Turbine 16A
Parameter: Operating Hours
Limit: Less than 2,000 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
	(Hrs.)	***(Hrs.)***	***(Hrs.)***
	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:_____

DRAFT

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

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Turbine 16B
Parameter: Operating Hours
Limit: Less than 2,000 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
	(Hrs.)	***(Hrs.)***	***(Hrs.)***
	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:_____

DRAFT

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

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Combustion Turbines Units 19A, 19B, 19C, and 20
Parameter: PM Emissions
Limit: Shall not exceed 61.04 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	PM Emissions (tons)	***PM Emissions (tons)***	***PM Emissions (tons)***
	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:_____

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

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Combustion Turbines Units 19A, 19B, 19C, and 20
Parameter: VOC Emissions
Limit: Shall not exceed 79.70 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	VOC Emissions (tons)	***VOC Emissions (tons)***	***VOC Emissions (tons)***
	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:_____

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

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Combustion Turbines 21A, 21B, 22A, and 22B
Parameter: Combined PM Emissions
Limit: Shall not exceed 120.3 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	Combined PM Emissions (tons)	***Combined PM Emissions (tons)***	***Combined PM Emissions (tons)***
	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:_____

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

Part 70 Quarterly Report

Source Name:	Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address:	2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.:	T 073-45762-00008
Facility:	Combustion Turbines 21A, 21B, 22A, and 22B and their associated duct burners
Parameter:	Combined NOx Emissions
Limit:	Shall not exceed 1,566.3 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	Combined NOx Emissions (tons)	***Combined NOx Emissions (tons)***	***Combined NOx Emissions (tons)***
	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:_____

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

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Combustion Turbines 21A, 21B, 22A, and 22B
Parameter: Total VOC Emissions during any periods of startup and shutdown
Limit: Shall not exceed 25.6 tons per twelve (12) consecutive month period, per combustion turbine, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____ CT:_____

Month	Column 1	Column 2	Column 1 + Column 2
	Total VOC Emissions (tons)	***Total VOC Emissions (tons)***	***Total VOC Emissions (tons)***
	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:_____

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

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Combustion Turbines 21A, 21B, 22A, and 22B
Parameter: Total GHGs Emissions
Limit: Shall not exceed 850,447 tons per twelve (12) consecutive month period, per turbine, when operating in simple cycle mode including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____ CT:_____

Month	Column 1	Column 2	Column 1 + Column 2
	Total GHGs Emissions (tons)	***Total GHGs Emissions (tons)***	***Total GHGs Emissions (tons)***
	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:_____

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

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Combustion Turbines 21A, 21B, 22A, and 22B
Parameter: Total GHGs Emissions
Limit: Shall not exceed 1,733,520 tons per twelve (12) consecutive month period, per turbine, when operating in combined cycle mode including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____ CT:_____

Month	Column 1	Column 2	Column 1 + Column 2
	Total GHGs Emissions (tons)	***Total GHGs Emissions (tons)***	***Total GHGs Emissions (tons)***
	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:_____

DRAFT

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: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008

Months: _____ to _____ Year: _____

This report shall be submitted quarterly based on a calendar year. Proper notice submittal under Section C - Malfunctions Report satisfies the reporting requirements of paragraph (a) of Section C-General Reporting. Any deviation from the requirements of this permit, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. A deviation required to be reported pursuant to an applicable requirement that exists independent of the permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".

☐ NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.

☐ THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD

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

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

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

Form Completed by:_____

Title / Position: _____

Date:_____

Phone: _____

Attachment E

Part 70 Operating Permit No: 073-45762-00008

[Downloaded from the eCFR on January 20, 2026]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart GG—Standards of Performance for Stationary Gas Turbines

§ 60.330 Applicability and designation of affected facility.

(a) Except as provided for in paragraphs (c) through (e) of this section, the provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of § 60.332.

(c) As an alternative to being subject to this subpart, the owner or operator of a stationary combustion turbine meeting the applicability of this subpart may petition the Administrator (in writing) to become subject to the requirements for modified units in subpart KKKKa of this part. If the Administrator grants the petition, the affected facility is no longer subject to this subpart and is subject to (unless the unit is modified or reconstructed in the future) the requirements for modified units in subpart KKKKa of this part. The Administrator can only grant the petition if it is determined that compliance with subpart KKKKa of this part would be equivalent to, or more stringent than, compliance with this subpart.

(d) Stationary gas turbines subject to subpart Da, KKKK, or KKKKa of this part are not subject to this subpart.

(e) A combustion turbine that is subject to this subpart and is not a “major source” or located at a “major source” (as that term is defined at 42 U.S.C. 7661 (2)) is exempt from the requirements of 42 U.S.C. 7661a(a).

[44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000; 91 FR 1975, Jan. 15, 2026]

§ 60.331 Definitions.

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

(a) ***Stationary gas turbine*** means any simple cycle gas turbine, regenerative cycle gas turbine, or any gas turbine portion of a combined cycle steam/electric generating system that is not self-propelled. It may, however, be mounted on a vehicle for portability. Portable combustion turbines are excluded from the definition of “stationary combustion turbine,” and not regulated under this part, if the turbine meets the definition of “nonroad engine” under title II of the Clean Air Act and applicable regulations and is certified to meet emission standards promulgated pursuant to title II of the Clean Air Act, along with all related requirements.

(b) ***Simple cycle gas turbine*** means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) ***Regenerative cycle gas turbine*** means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) ***Combined cycle gas turbine*** means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) ***Emergency gas turbine*** means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) ***Ice fog*** means an atmospheric suspension of highly reflective ice crystals.

(g) ***ISO standard day conditions*** means 288 degrees Kelvin (15 °C, 59 °F), 60 percent relative humidity, and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

(h) ***Efficiency*** means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) ***Peak load*** means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) ***Base load*** means the load level at which a gas turbine is normally operated.

(k) ***Fire-fighting turbine*** means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) ***Turbines employed in oil/gas production or oil/gas transportation*** means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m)-(n) [Reserved]

(o) ***Garrison facility*** means any permanent military installation.

(p) ***Gas turbine model*** means a group of gas turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature, and turbine inlet pressure.

(q) ***Electric utility stationary gas turbine*** means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

(r) ***Emergency fuel*** is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.

(s) ***Unit operating hour*** means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

(t) ***Excess emissions*** means a specified averaging period over which either:

(1) The NO_X emissions are higher than the applicable emission limit in § 60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in § 60.333; or

(3) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

(u) ***Natural gas*** means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane) that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 15.5 degrees Celsius total sulfur. Additionally, natural gas must be composed of at least 70 percent methane by volume and have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Unless refined to meet the definition of natural gas in this paragraph (u), natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

(v) ***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 heat recovery steam generating unit.

(w) ***Lean premix stationary combustion turbine*** means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) ***Diffusion flame stationary combustion turbine*** means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) ***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 unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004; 91 FR 1976, Jan. 15, 2026]

§ 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075\frac{(14.4)}{Y} + F$$

Where:

STD = allowable ISO corrected (if required as given in § 60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0150\frac{(14.4)}{Y} + F$$

Where:

STD = allowable ISO corrected (if required as given in § 60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this section is optional. That is, the owner or operator may choose to apply a NO_X allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NO_X emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under § 60.8 as follows:

Fuel-bound nitrogen (percent by weight)	**F (NO_X percent by volume)**
N ≤ .015	0
0.015 <N≤0.1	0.04 (N)
0.1<N≤0.25	0.004 + 0.0067(N-0.1)
N >0.25	0.005

Where:

N = the nitrogen content of the fuel (percent by weight).

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by § 60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the Federal Register.

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in § 60.332(b) shall comply with paragraph (a)(2) of this section.

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NO_X emissions are exempt from paragraph (a) of this section when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and firefighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) of this section on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979, Federal Register (44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004; 91 FR 1976, Jan. 15, 2026]

§ 60.333 Standard for sulfur dioxide.

Except as provided in paragraph (c) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, every owner or operator subject to the provisions of this subpart shall comply with one or the other of the following conditions in paragraphs (a) and (b) of this section:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis; or

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

(c) Stationary gas turbines subject to either subpart J or Ja of this part are not subject to the SO_2 standards in this subpart.

[44 FR 52798, Sept. 10, 1979, as amended at 69 FR 41360, July 8, 2004; 91 FR 1976, Jan. 15, 2026]

§ 60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NO_X emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_X emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors. As an alternative, a CO_2 monitor may be used to adjust the measured NO_X concentrations to 15 percent O_2 by either converting the CO_2 hourly averages to equivalent O_2 concentrations using Equation F-14a or F-14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O_2, or by using the CO_2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO_X and diluent monitors may be performed individually or on a combined basis, *i.e.*, the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NO_X) and a percent O_2 basis for oxygen; or

(ii) On a ppm at 15 percent O_2 basis; or

(iii) On a ppm basis (for NO_X) and a percent CO_2 basis (for a CO_2 monitor that uses the procedures in Method 20 to correct the NO_X data to 15 percent O_2).

(2) As specified in § 60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in § 60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both NO_X and diluent, the data acquisition and handling system must calculate and record the hourly NO_X emissions in the units of the applicable NO_X emission standard under § 60.332(a), *i.e.*, percent NO_X by volume, dry basis, corrected to 15 percent O_2 and International Organization for Standardization (ISO) standard conditions (if required as given in § 60.335(b)(1)). For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.

(iii) If the owner or operator has installed a NO_X CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at subpart D of part 75, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in § 60.7(c). For affected units that are also regulated under part 75, the NO_X emission rate may be monitored

using a NO_X diluent CEMS that is installed and certified in accordance with appendix A to part 75 and the QA program in appendix E to part 75, or the low mass emissions methodology in § 75.19 of this chapter.

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO_X emissions, the owner or operator may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA, State, or local permitting authority approval of a procedure for monitoring compliance with the applicable NO_X emission limit under § 60.332, that approved procedure may continue to be used.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NO_X emissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NO_X CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NO_X emissions, may, but is not required to, elect to use a NO_X CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. Other acceptable monitoring approaches include periodic testing approved by EPA or the State or local permitting authority or continuous parameter monitoring as described in paragraph (f) of this section.

(f) The owner or operator of a new turbine that commences construction after July 8, 2004, which does not use water or steam injection to control NO_X emissions may, but is not required to, perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NO_X formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.

(3) For any turbine that uses SCR to reduce NO_X emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in § 75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in § 75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under § 60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in § 75.19 of this chapter or the NO_X emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in § 75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in § 60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4,000 ppmw), ASTM D4084-82, D4084-94, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference, see § 60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (*i.e.*, if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in § 60.332). The nitrogen content of the fuel shall be determined using methods described in § 60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in § 60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) ***Fuel oil.*** For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) ***Gaseous fuel.*** Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) ***Custom schedules.*** Notwithstanding the requirements of paragraph (i)(2) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in § 60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), subsequent sulfur content monitoring may be performed at 12 month intervals. If any of the samples taken at 12-month intervals has a total sulfur content between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(*1*) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(*2*) of this section.

(*2*) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(*3*) of this section.

(*3*) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (*i.e.*, the maximum total sulfur content of natural gas as defined in § 60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with § 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under § 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with § 60.332, as established during the performance test required in § 60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in § 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of § 60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in § 60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using NO_X and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_X concentration exceeds the applicable emission limit in § 60.332(a)(1) or (2). For the purposes of this subpart, a “4-hour rolling average NO_X concentration” is the arithmetic average of the average NO_X concentration measured by the CEMS for a given hour (corrected to 15 percent O_2 and, if required under § 60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_X concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_X concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in § 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of § 60.335(b)(1).

(iv) For owners or operators that elect, under paragraph (f) of this section, to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(A) An excess emission shall be a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (*i.e.*, daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) ***Ice fog.*** Each period during which an exemption provided in § 60.332(f) is in effect shall be reported in writing to the Administrator in the semiannual report described in paragraph (k)(3) of this section. For each period, the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported.

(4) ***Emergency fuel.*** Each period during which an exemption provided in § 60.332(k) is in effect shall be included in the report required in § 60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under § 60.7(c) shall be postmarked by the 30th day following the end of each 6-month period.

(k) The reporting requirements for this subpart shall be as follows:

(1) ***Reporting frequency.*** All reports required under § 60.7(c) must be electronically submitted via the Compliance and Emissions Data Reporting Interface (CEDRI) by the 30th day following the end of each 6-month period.

(2) ***Electronic reporting.*** Beginning on March 16, 2026, within 60 days after the date of completing each performance test or CEMS performance evaluation that includes a RATA, you must submit the results following the procedures specified in paragraph (k)(4) of this section. You must submit the report in a file format generated using the EPA's Electronic Reporting Tool (ERT). Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) accompanied by the other information required by § 60.8(f)(2) in PDF format.

(3) ***General reporting requirements.*** You must submit to the Administrator semiannual reports of the following recorded information. Beginning on January 15, 2027, or once the report template for this subpart has been available on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for one year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (k)(4) of this section. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated

State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(4) ***CEDRI and CBI.*** If you are required to submit notifications or reports following the procedure specified in this paragraph (k)(4), you must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (k)(4)(i) and (ii) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (k)(4).

(i) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqps_cbi@epa.gov,* and as described above, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Combustion Turbine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqps_cbi@epa.gov* to request a file transfer link.

(ii) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Office, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. In addition to the OAQPS Document Control Officer, ERT files should also be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should also be sent to the attention of the Stationary Combustion Turbine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(5) ***System outage.*** If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (k)(5)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning 5 business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(6) ***Force majeure.*** If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure,* you must meet the requirements outlined in paragraphs (k)(6)(i) through (v) of this section.

(i) You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the *force majeure* event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of notification, the date you reported.

(iv) The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs.

(7) ***Record availability.*** Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41360, July 8, 2004; 71 FR 9457, Feb. 24, 2006; 91 FR 1976, Jan. 15, 2026]

§ 60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in § 60.8, using either

(1) EPA Method 20,

(2) ASTM D6522-00 (incorporated by reference, see § 60.17), or

(3) To determine NO_X and diluent concentration:

(i) Either EPA Method 7E in appendix A-4 to this part or EPA Method 320 in appendix A to part 63 of this chapter; and

(ii) Either EPA Method 3 or 3A in appendix A to this part.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O_2, is within ±10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NO_X concentration during the stratification test; or

(B) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O_2, is within ±5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O_2, is within 10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NO_X concentration during the stratification test; or

(B) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O_2, is within 5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in § 60.332 and shall meet the performance test requirements of § 60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NO_{Xo}) corrected to 15 percent O_2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

$$NO_X = (NO_{Xo})(P_r/P_o)^{0.5}\, e^{19\,(Ho-0.00633)}\, (288\ °K/T_a)^{1.53}$$

Where:

NO_X = emission concentration of NO_X at 15 percent O_2 and ISO standard ambient conditions, ppm by volume, dry basis,

NO_{Xo} = mean observed NO_X concentration, ppm by volume, dry basis, at 15 percent O_2,

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure. Alternatively, you may use 760 mm Hg (29.92 in Hg),

P_o = observed combustor inlet absolute pressure at test, mm Hg. Alternatively, you may use the barometric pressure for the date of the test,

H_o = observed humidity of ambient air, g H_2O/g air,

e = transcendental constant, 2.718, and

T_a = ambient temperature, °K.

(2) The 3-run performance test required by § 60.8 must be performed within ±5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in § 60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NO_X emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NO_X emission limit in § 60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with § 60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522-00 (incorporated by reference, see § 60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable § 60.332 NO_X emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in § 60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in § 60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NO_X CEMS under § 60.334(e), then the initial performance test required under § 60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load while the source is combusting the fuel that is a normal primary fuel for that source.

(ii) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under § 60.332 and to provide the required reference method data for the RATA of the CEMS described under § 60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator elects under § 60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in § 60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597-94 (Reapproved 1999), D6366-99, D4629-02, D5762-02 (all of which are incorporated by reference, *see* § 60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate within ±5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under § 60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129-00, D2622-98, D4294-02, D1266-98, D5453-00 or D1552-01 (all of which are incorporated by reference, *see* § 60.17); or

(ii) For gaseous fuels, ASTM D1072-80, D1072-90 (Reapproved 1994); D3246-81, D3246-92, D3246-96; D4468-85 (Reapproved 2000); or D6667-01 (all of which are incorporated by reference, see § 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

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

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in § 60.8 to ISO standard day conditions.

[69 FR 41363, July 8, 2004, as amended at 71 FR 9458, Feb. 24, 2006; 79 FR 11250, Feb. 27, 2014; 91 FR 1978, Jan. 15, 2026]

Attachment I

Part 70 Operating Permit No: 073-45762-00008

[Downloaded from the eCFR on January 20, 2026]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

Source:71 FR 38497, July 6, 2006, unless otherwise noted.

Introduction

§ 60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Applicability

§ 60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine engine should be included when determining whether or not this subpart is applicable to your combustion turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are not subject to subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are not subject to subparts Da, Db, and Dc of this part.

(c) Stationary combustion turbines subject to subpart KKKKa of this part are not subject to this subpart.

(d) As an alternative to being subject to this subpart, the owner or operator of an affected stationary combustion turbine meeting the applicability of this subpart may petition the Administrator (in writing) to become subject to the requirements for modified units in subpart KKKKa of this part. If the Administrator grants the petition, the affected facility is no longer subject to this subpart and is subject to (unless the unit is modified or reconstructed in the future) the requirements for modified units under subpart KKKKa of this part. The Administrator can only grant the petition if it is determined that compliance with subpart KKKKa of this part would be equivalent to, or more stringent than, compliance with this subpart.

(e) Stationary gas turbines subject to title II of the Clean Air Act are not subject to this subpart.

[91 FR 1978, Jan. 15, 2026]

§ 60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in § 60.4420(i), are exempt from the nitrogen oxides (NO_X) emission limits in § 60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NO_X emission limits in § 60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

(e) Military combustion turbines for use in other than a garrison facility and military combustion turbines installed for use as military training facilities are exempt from the NO_X standards in this subpart.

(f) A combustion turbine that is subject to this subpart and is not a “major source” or located at a “major source” (as that term is defined at 42 U.S.C. 7661 (2)) is exempt from the requirements of 42 U.S.C. 7661a(a).

[71 FR 38497, July 6, 2006, as amended at 91 FR 1978, Jan. 15, 2026]

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_X) and sulfur dioxide (SO_2).

§ 60.4320 What emission limits must I meet for nitrogen oxides (NO_X)?

(a) Except as provided for in paragraph (c) of this section, you must meet the emission limits for NO_X specified in table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X.

(c) A stationary combustion turbine that combusts byproduct fuels for which a facility-specific NO_X emission standard has been established by the Administrator or delegated authority according to the requirements of paragraphs (c)(1) and (2) of this section is exempt from the emission limits specified in table 1 to this subpart.

(1) You may request a facility-specific NO_X emission standard by submitting a written request to the Administrator or delegated authority explaining why your affected facility, when combusting the byproduct fuel, is unable to comply with the applicable NO_X emission standard determined using table 1 to this subpart.

(2) If the Administrator or delegated authority approves the request, a facility-specific NO_X emissions standard will be established in a manner that the Administrator or delegated authority determines to be consistent with minimizing NO_X emissions.

[71 FR 38497, July 6, 2006, as amended at 91 FR 1979, Jan. 15, 2026]

§ 60.4325 What emission limits must I meet for NO_X if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in table 1 to this subpart. If your turbine operates below 75 percent of the peak load at any point during an operating hour, the part load standard is applicable during the entire operating hour. For non-part load operating hours, if your heat input is greater than or equal to 50 percent fuels other than natural gas at any point during an operating hour, you must meet the corresponding limit for fuels other than natural gas for that operating hour. For non-part load operating hours when your total heat input is greater than 50 percent natural gas for the entire operating hour while combusting some portion of non-natural gas fuels, you must meet the corresponding emissions standard as determined by prorating the applicable NO_X standards, based on the applicable size category in table 1 to this subpart, by the heat input from each fuel type.

[91 FR 1979, Jan. 15, 2026]

§ 60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or

(3) For each stationary combustion turbine burning 50 percent or more biogas and/or low-Btu gas on a calendar month basis, as determined based on total heat input, you must not cause to be discharged into the atmosphere from the affected source any gases that contain SO_2 in excess of:

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

(c) A stationary combustion turbine subject to either subpart J or Ja of this part is not subject to the SO_2 performance standards in this subpart.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009; 91 FR 1979, Jan. 15, 2026]

§ 60.4331 What are the requirements for operating a stationary temporary combustion turbine?

(a) Notwithstanding any other provision of this subpart, you may operate a small- or medium-size stationary combustion turbine (*i.e.,* combustion turbine with a base load rating less than or equal to 850 MMBtu/h) at a single location for up to 24 consecutive months, so long as you comply with all of the requirements in paragraphs (b) through (e) of this section.

(b) You must meet the NO_X emissions standard for stationary temporary combustion turbines in table 1 to this subpart and the applicable SO_2 emissions standard in § 60.4330.

(c) Unless you elect to demonstrate compliance through the otherwise-applicable monitoring, recordkeeping, and reporting requirements of this subpart, compliance with the NO_X emissions standard must be demonstrated through maintaining the documentation in paragraphs (c)(1) and (2) of this section on-site:

(1) Each stationary temporary combustion turbine has a manufacturer's emissions guarantee at or below the full load NO_X emissions standard in table 1 to this subpart; and

(2) Each such turbine has been performance tested at least once in the prior 5 years as meeting the NO_X emissions standard in table 1 to this subpart.

(d) Unless you elect to demonstrate compliance through the otherwise-applicable monitoring, recordkeeping, and reporting requirements of this subpart, compliance with the SO_2 emissions standard must be demonstrated through complying with the provisions in § 60.4365.

(e) The conditions in paragraphs (e)(1) through (3) of this section apply in determining whether your stationary combustion turbine qualifies as a stationary temporary combustion turbine.

(1) The turbine may only be located at the same stationary source (or group of stationary sources located within a contiguous area and under common control) for a total period of 24 consecutive months. This is the total period of residence time allowed after the turbine commences operation at the location, regardless of whether the turbine is in operation for the entire 24-consecutive-month period.

(2) Any temporary combustion turbine that replaces a temporary combustion turbine at a stationary source and performs the same or similar function will be included in calculating the consecutive time period.

(3) The relocation of a stationary temporary combustion turbine within a single stationary source (or a group of stationary sources located within a contiguous area and under common control) while performing the same or similar function (*i.e.,* serving the same electric, mechanical, or thermal load) does not restart the 24-calendar-month residence time period.

[91 FR 1979, Jan. 15, 2026]

General Compliance Requirements

§ 60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) For multiple combustion turbines and with a common heat recovery unit, heat recovery units utilizing a common steam header, or using a common stack, the owner or operator shall either:

(1) Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit. The applicable emissions standard for the affected facility is equal to the prorated (by heat input) emissions standards of each of the individual combustion turbine engines that are exhausted through the single heat recovery steam generating unit;

(2) For combustion turbines complying with an output-based standard, develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part; or

(3) Monitor each combustion turbine separately by measuring the NO_X emissions prior to mixing in the common stack.

[71 FR 38497, July 6, 2006, as amended at 91 FR 1979, Jan. 15, 2026]

Monitoring

§ 60.4335 How do I demonstrate compliance for NO_X if I use water or steam injection?

(a) If you are using water or steam injection to control NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_X emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

(5) For affected units that are also regulated under part 75 of this chapter, the NO_X emission rate may be monitored using a NO_X diluent CEMS that is installed and certified in accordance with appendix A to part 75 and the QA program in appendix E to part 75, or the low mass emissions methodology in § 75.19 of this chapter.

[71 FR 38497, July 6, 2006, as amended at 91 FR 1980, Jan. 15, 2026]

§ 60.4340 How do I demonstrate continuous compliance for NO_X if I do not use water or steam injection?

(a) Except as provided for in paragraphs (a)(1) through (4) of this section, if you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests (no more than 14 calendar months following the previous performance test) in accordance with § 60.4400 to demonstrate continuous compliance.

(1) If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.

(2) An affected facility that has not operated for the 60 calendar days prior to the due date of a performance test is not required to perform the subsequent performance test until 45 calendar days after the next operating day. The Administrator or delegated authority must be notified of recommencement of operation consistent with § 60.4375(d).

(3) If you own or operate an affected facility that has operated 168 operating hours or less in total or with a particular fuel since the date the previous performance test was required to be conducted, you may request an extension from the otherwise required performance test until after the affected facility has operated more than 168 operating hours in total or with a particular fuel since the date of the previous performance test was required to be conducted. A request for an extension under this paragraph (a)(3) must be addressed to the relevant air division or office director of the appropriate Regional Office of the U.S. EPA as identified in § 60.4(a) for his or her approval at least 30 calendar days prior to the date on which the performance test is required to be conducted. If an extension is approved, a performance test must be conducted within 45 calendar days after the

day the facility reaches 168 hours of operation since the date the previous performance test was required to be conducted. When the facility has operated more than 168 operating hours since the date the previous performance test was required to be conducted, the Administrator or delegated authority must be notified consistent with § 60.4375(d).

(4) For a facility at which a group consisting of no more than five similar stationary combustion turbines (*i.e.,* same manufacturer and model number) is operated, you may request the use of a custom testing schedule by submitting a written request to the Administrator or delegated authority. The minimum requirements of the custom schedule include the conditions specified in paragraphs (a)(4)(i) through (v) of this section.

(i) Emissions from the most recent performance test for each individual affected facility are 75 percent or less of the applicable standard;

(ii) Each stationary combustion turbine uses the same emissions control technology;

(iii) Each stationary combustion turbine is operated in a similar manner;

(iv) Each stationary combustion turbine and its emissions control equipment are maintained according to the manufacturer's recommended maintenance procedures; and

(v) A performance test is conducted on each facility at least once every 5 calendar years.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§ 60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO_X formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.

(iii) For any turbine that uses SCR to reduce NO_X emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, you can monitor the NO_X emission rate using the methodology in appendix E to part 75, or the low mass emissions methodology in § 75.19 of this chapter, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of appendix E to part 75 or in § 75.19(c)(1)(iv)(H).

[71 FR 38497, July 6, 2006, as amended at 91 FR 1980, Jan. 15, 2026]

§ 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NO_X CEMS is chosen:

(a) Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A to part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in § 60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may satisfy the requirements of this paragraph (e) by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

[71 FR 38497, July 6, 2006, as amended at 91 FR 1980, Jan. 15, 2026]

§ 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in § 60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in § 60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) [Reserved]

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under § 60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under § 60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

Equation 1 to Paragraph (f)(1)

$$E = \frac{(NO_X)_h \times (HI)_h}{P} \quad (Eq. 1)$$

Where:

E = hourly NO_X emission rate, in lb/MWh;

$(NO_X)h$ = hourly NO_X emission rate, in lb/MMBtu;

(HI)h = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.,* calculated using Equation D-15a in appendix D to part 75 of this chapter; and

P = gross energy output of the combustion turbine in MW. For an hour in which there is zero electrical load, you may calculate the pollutant emission rate using a default electrical load value equivalent to 5 percent of the maximum sustainable electrical load of the turbine.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \quad (Eq. 2)$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

$(Pe)_t$ = electrical or mechanical energy output of the combustion turbine in MW,

$(Pe)_c$ = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$P_s = \frac{Q * H}{3.413 \text{ x } 10^6 \text{ Btu/MWh}} \quad (Eq. 3)$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 × 10_6 = conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_X)_m}{BL * AL} \qquad (Eq. 4)$$

Where:

E = NO_X emission rate in lb/MWh,

$(NO_X)_m$ = NO_X emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in § 60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in § 60.4380(b)(1).

[71 FR 38497, July 6, 2006, as amended at 91 FR 1980, Jan. 15, 2026]

§ 60.4355 How do I establish and document a proper parameter monitoring plan?

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§ 60.4335 and 60.4340 must be monitored during the performance test required under § 60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO_X emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter, you may meet the requirements of this paragraph (b) by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in § 75.19(e)(5) of this chapter or in section 2.3 of appendix E to part 75 and section 1.3.6 of appendix B to part 75.

[71 FR 38497, July 6, 2006, as amended at 91 FR 1981, Jan. 15, 2026]

§ 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in § 60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in § 60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084-05, D4810-88 (Reapproved 1999), D5504-01, or D6228-98 (Reapproved 2003), or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference, see § 60.17), which measure the major sulfur compounds, may be used.

[91 FR 1981, Jan. 15, 2026]

§ 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

§ 60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) ***Fuel oil.*** For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) ***Gaseous fuel.*** If you elect not to demonstrate sulfur content using options in § 60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) ***Custom schedules.*** Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in § 60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

Reporting

§ 60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with § 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) The notification requirements of § 60.8 apply to the initial and subsequent performance tests.

(c) An owner or operator of an affected facility complying with § 60.4340(a)(2) must notify the Administrator or delegated authority within 15 calendar days after the facility recommences operation.

(d) An owner or operator of an affected facility complying with § 60.4340(a)(3) must notify the Administrator or delegated authority within 15 calendar days after the facility has operated more than 168 operating hours since the date the previous performance test was required to be conducted.

(e) Beginning on March 16, 2026, within 60 days after the date of completing each performance test or continuous emissions monitoring systems (CEMS) performance evaluation that includes a RATA, you must submit the results following the procedures specified in paragraph (g) of this section. You must submit the report in a file format generated using the EPA's Electronic Reporting Tool (ERT). Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) accompanied by the other information required by § 60.8(f)(2) in PDF format.

(f) You must submit to the Administrator semiannual reports of the following recorded information. Beginning on January 15, 2027, or once the report template for this subpart has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for one year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for this subpart and following the procedure specified in paragraph (g) of this section. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(g) If you are required to submit notifications or reports following the procedure specified in this paragraph (g), you must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information

claimed to be CBI, to the EPA following the procedures in paragraphs (g)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (g).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqps_cbi@epa.gov,* and as described above, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Combustion Turbine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqps_cbi@epa.gov* to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Office, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. In addition to the OAQPS Document Control Officer, ERT files should also be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should also be sent to the attention of the Stationary Combustion Turbine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(h) If you are required to electronically submit a report through CEDRI in EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (h)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning 5 business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(i) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure,* you must meet the requirements outlined in paragraphs (i)(1) through (5) of this section.

(1) You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large-scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the *force majeure* event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after *the force majeure* event occurs.

(j) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

[91 FR 1981, Jan. 15, 2026]

§ 60.4380 How are excess emissions and monitor downtime defined for NO_X?

For the purpose of reports required under § 60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with § 60.4320, as established during the performance test required in § 60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NO_X control will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§ 60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in § 60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For averaging periods during which multiple emissions standards apply, the applicable standard for the averaging period is the heat input weighted average of the applicable standards during each hour. For hours with multiple emission standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

[71 FR 38497, July 6, 2006, as amended at 91 FR 1982, Jan. 15, 2026]

§ 60.4385 How are excess emissions and monitoring downtime defined for SO_2?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

§ 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

(a) If you operate an emergency combustion turbine, you are exempt from the NO_X limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO_X limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§ 60.4395 What must I submit my reports?

All reports required under § 60.7(c) must be electronically submitted via CEDRI by the 30th day following the end of each 6-month period.

[91 FR 1982, Jan. 15, 2026]

Performance Tests

§ 60.4400 How do I conduct the initial and subsequent performance tests, regarding NO_X?

(a) You must conduct an initial performance test, as required in § 60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E in appendix A-4 to this part, EPA Method 20 in appendix A-7 to this part, EPA Method 320 in appendix A of part 63 of this chapter, or ASTM D6348-12 (Reapproved 2020) (incorporated by reference, see § 60.17). For units complying with the output-based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A to this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

Equation 1 to Paragraph (a)(1)(i)

$$E = \frac{1.194 \times 10^{-7} \times (NO_X)_c \times Q_{std}}{P} (Eq. 1)$$

Where:

E = NO_X emission rate, in lb/MWh;

1.194×10^{-7} = conversion constant, in lb/dscf-ppm;

$(NO_X)_c$ = average NO_X concentration for the run, in ppm;

Q_{std} = stack gas volumetric flow rate, in dscf/hr; and

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple cycle operation), for combined cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to § 60.4350(f)(2); or

(ii) Measure the NO_X and diluent gas concentrations, using either EPA Methods 7E and 3A or EPA Method 20 in appendix A to this part. In addition, when only natural gas is being combusted, ASTM D6522-20 (incorporated by reference, see § 60.17) can be used instead of EPA Method 3A in appendix A-2 to this part or EPA Method 20 in appendix A-7 to this part to determine the oxygen content in the exhaust gas. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A to this part to calculate the NO_X emission rate in lb/MMBtu. Then, use equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the NO_X emission rate in lb/MWh.

(2) Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or

(B) For turbines with a NO_X standard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO_2 (or O_2) from the mean for all traverse points; or

(C) For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation within 25 percent of 100 percent of the peak load rating of the duct burners or the highest achievable load if at least 75 percent of the peak load of the duct burners cannot be achieved during the performance test.

(3) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and you choose to monitor the steam or water to fuel ratio in accordance with § 60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable § 60.4320 NO_X emission limit.

(4) Compliance with the applicable emission limit in § 60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in § 60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in § 60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

[71 FR 38497, July 6, 2006, as amended at 91 FR 1982, Jan. 15, 2026]

§ 60.4405 How do I perform the initial performance test if I have chosen to install a NO_X-diluent CEMS?

If you elect to install and certify a NO_X-diluent CEMS under § 60.4345, then the initial performance test required under § 60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load, while the source is combusting the fuel that is a normal primary fuel for that source. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under § 60.4320 and to provide the required reference method data for the RATA of the CEMS described under § 60.4335.

(d) Compliance with the applicable emission limit in § 60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

[71 FR 38497, July 6, 2006, as amended at 91 FR 1983, Jan. 15, 2026]

§ 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls in accordance with § 60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in § 60.4355.

§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in § 60.8. An owner or operator of an affected facility complying with the fuel-based standard may use fuel records (such as a current, valid purchase contract, tariff sheet, transportation contract, or results of a fuel analysis) to satisfy the requirements of § 60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are four methodologies that you may use to conduct the performance tests.

(1) The use of a current, valid purchase contract, tariff sheet, or transportation contract for the fuel specifying the maximum total sulfur content of all fuels combusted in the affected facility. Alternately, the fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter may be used.

(2) Periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample may be collected either by an automatic sampling system or manually. For automatic sampling, follow ASTM D5287-97 (Reapproved 2002) (incorporated by reference, see § 60.17) for gaseous fuels or ASTM D4177-95 (Reapproved 2000) (incorporated by reference, see § 60.17) for liquid fuels. For manual sampling of gaseous fuels, follow API Manual of Petroleum Measurement Standards, Chapter 14, Section 1; GPA 2166-17; or ISO 10715:1997(E) (all incorporated by reference, see § 60.17). For manual sampling of liquid fuels, follow GPA 2174-14 or the procedures for manual pipeline sampling in section 14 of ASTM D4057-95 (Reapproved 2000) (both incorporated by reference, see § 60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129-00 (Reapproved 2005), or alternatively D1266-98 (Reapproved 2003), D1552-03, D2622-05, D4294-03, D5453-05, D5623-19, or D7039-15a (all incorporated by reference, see § 60.17); or

(ii) For gaseous fuels, ASTM D1072-90 (Reapproved 1999), or alternatively D3246-05, D4084-05, D4468-85 (Reapproved 2000), D4810-88 (Reapproved 1999), D6228-98 (Reapproved 2003), D6667-04, or GPA 2140-17, 2261-19, or 2377-86 (all incorporated by reference, see § 60.17).

(3) Measure the SO_2 concentration (in parts per million (ppm)), using EPA Method 6, 6C, 8, or 20 in appendix A to this part. For units complying with the output-based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A to this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO_2 emission rate:

Equation 1 to Paragraph (a)(3)

$$E = \frac{1.664 \times 10^{-7} \times (SO_2)_c \times Q_{std}}{P} \ (Eq.1)$$

Where:

E = SO_2 emission rate, in lb/MWh;

1.664 × 10^{-7} = conversion constant, in lb/dscf-ppm;

$(SO_2)_c$ = average SO_2 concentration for the run, in ppm;

Q_{std} = stack gas volumetric flow rate, in dscf/hr; and

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to § 60.4350(f)(2); or

(4) Measure the SO_2 and diluent gas concentrations, using either EPA Method 6, 6C, or 8 and 3A, or 20 in appendix A to this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A to this part to calculate the SO_2 emission rate in lb/MMBtu. Then, use equations 1 and, if necessary, 2 and 3 in § 60.4350(f) to calculate the SO_2 emission rate in lb/MWh.

(b) [Reserved]

[71 FR 38497, July 6, 2006, as amended at 85 FR 63410, Oct. 7, 2020; 91 FR 1983, Jan. 15, 2026]

Definitions

§ 60.4420 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

Biogas means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and CO_2.

Byproduct means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, pulp and paper mills, or other industrial facilities (except natural gas and fuel oil).

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire (*e.g.,* firefighting turbine) or flood, etc. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, agencies, or departments, voluntary consensus standards, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the combustion turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion

turbines. Emergency combustion turbines do not include combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors.

Excess emissions means a specified averaging period over which either

(1) the NO_X emissions are higher than the applicable emission limit in § 60.4320;

(2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in § 60.4330; or

(3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Firefighting turbine means any stationary combustion turbine that is used solely to pump water for extinguishing fires.

Garrison facility means any permanent military installation.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Low-Btu gas means any gaseous fuels that have heating values less than 26 megajoules per standard cubic meter (MJ/scm) (700 Btu/scf).

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane) that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must be composed of at least 70 percent methane by volume and have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Unless refined to meet this definition of natural gas, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore turbines.

Offshore turbine means a stationary combustion turbine located on a platform or facility in an ocean, territorial sea, the outer continental shelf, or the Great Lakes of North America and stationary combustion turbines located in a coastal management zone and elevated on a platform.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. Portable combustion turbines are excluded from the definition of “stationary combustion turbine,” and not regulated under this part, if the turbine meets the definition of “nonroad engine” under title II of the Clean Air Act and applicable regulations and is certified to meet emission standards promulgated pursuant to title II of the Clean Air Act, along with all related requirements.

Temporary combustion turbine means a combustion turbine that is intended to and remains at a single stationary source (or group of stationary sources located within a contiguous area and under common control) for 24 consecutive months or less.

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

Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009; 91 FR 1984, Jan. 15, 2026]

Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines		
Combustion turbine type	**Combustion turbine heat input at peak load (HHV)**	**NO_X emission standard**
New turbine firing natural gas, electric generating	≤50 MMBtu/h	42 ppm at 15 percent O_2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤50 MMBtu/h	100 ppm at 15 percent O_2 or 690 ng/J of useful output (5.5 lb/MWh).

Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines		
Combustion turbine type	**Combustion turbine heat input at peak load (HHV)**	**NO_X emission standard**
New turbine firing natural gas	>50 MMBtu/h and ≤850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	>850 MMBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating	≤50 MMBtu/h	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive	≤50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	>50 MMBtu/h and ≤850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas	>850 MMBtu/h	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	>50 MMBtu/h and ≤850 MMBtu/h	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	>50 MMBtu/h and ≤850 MMBtu/h	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	≤300 MMBtu/h or ≤30 MW output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	>300 MMBtu/h and >30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).
Combustion turbines bypassing the heat recovery unit	>50 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).

[91 FR 1984, Jan. 15, 2026]

Attachment K

Part 70 Operating Permit No: 073-45762-00008

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Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Source: 72 FR 32742, June 13, 2007, unless otherwise noted.

§60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the particulate matter (PM) and nitrogen oxides (NO_X) standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are subject to the PM and NO_X standards under this subpart and to the sulfur dioxide (SO_2) standards under subpart D (§60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the NO_X standards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are also subject to the NO_X standards under this subpart and the PM and SO_2 standards under subpart D (§60.42 and §60.43).

(c) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

(d) Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; §60.50) are subject to the NO_X and PM standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; §60.40Da) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined under §60.281 is not considered a modification under §60.14 and the steam generating unit is not subject to this subpart.

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

(1) Section 60.44b(f).

(2) Section 60.44b(g).

(3) Section 60.49b(a)(4).

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, subpart AAAA, or subpart CCCC of this part is not subject to this subpart.

(i) Affected facilities (*i.e.,* heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other affected facilities (*i.e.* heat recovery steam generators with duct burners) that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the affected facility (*i.e.* heat recovery steam generator) is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, §60.40).

(k) Any affected facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart Cb or subpart BBBB of this part is not covered by this subpart.

(l) Affected facilities that also meet the applicability requirements under subpart BB of this part (Standards of Performance for Kraft Pulp Mills) are subject to the SO_2 and NO_X standards under this subpart and the PM standards under subpart BB.

(m) Temporary boilers are not subject to this subpart.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§60.41b Definitions.

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

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide (CO_2) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

Chemical manufacturing plants mean industrial plants that are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

Cogeneration, also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Coke oven gas means the volatile constituents generated in the gaseous exhaust during the carbonization of bituminous coal to form coke.

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

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

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17), diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see §60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see §60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO_2 control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under §60.49b(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Gaseous fuel means any fuel that is a gas at ISO conditions. This includes, but is not limited to, natural gas and gasified coal (including coke oven gas).

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.*, steam delivered to an industrial process).

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

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m^3 (70,000 Btu/hr-ft^3).

ISO Conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Low heat release rate means a heat release rate of 730,000 J/sec-m^3 (70,000 Btu/hr-ft^3) or less.

Mass-feed stoker steam generating unit means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Municipal-type solid waste means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Petroleum refinery means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems. For gasified coal or oil that is desulfurized prior to combustion, the *Potential sulfur dioxide emission rate* is the theoretical SO_2 emissions (ng/J or lb/MMBtu heat input) that would result from combusting fuel in a cleaned state without using any post combustion emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Pulp and paper mills means industrial plants that are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units. Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Temporary boiler means any gaseous or liquid fuel-fired steam generating unit that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and not located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.30 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005 and located in a noncontinental area, *very low sulfur oil* means oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 215 ng/J (0.50 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a SO_2 control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§60.42b Standard for sulfur dioxide (SO2).

(a) Except as provided in paragraphs (b), (c), (d), or (j) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and the emission limit determined according to the following formula:

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

Where:

E_s = SO_2 emission limit, in ng/J or lb/MMBtu heat input;

K_a = 520 ng/J (or 1.2 lb/MMBtu);

K_b = 340 ng/J (or 0.80 lb/MMBtu);

H_a = Heat input from the combustion of coal, in J (MMBtu); and

H_b = Heat input from the combustion of oil, in J (MMBtu).

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction,

or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable. For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(c) On and after the date on which the performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of SO_2 emissions, shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 50 percent of the potential SO_2 emission rate (50 percent reduction) and that contain SO_2 in excess of the emission limit determined according to the following formula:

$$E_s = \frac{(K_c H_c + K_d H_d)}{(H_c + H_d)}$$

Where:

E_s = SO2 emission limit, in ng/J or lb/MM Btu heat input;

K_c = 260 ng/J (or 0.60 lb/MMBtu);

K_d = 170 ng/J (or 0.40 lb/MMBtu);

H_c = Heat input from the combustion of coal, in J (MMBtu); and

H_d = Heat input from the combustion of oil, in J (MMBtu).

For facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section. For facilities complying with paragraphs (d)(1), (2), or (3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in this paragraph. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;

(2) Affected facilities located in a noncontinental area; or

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from

combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from the exhaust gases entering the duct burner; or

(4) The affected facility burns coke oven gas alone or in combination with natural gas or very low sulfur distillate oil.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.

(g) Except as provided in paragraph (i) of this section and §60.45b(a), the SO_2 emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential SO_2 emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential SO_2 emissions and

(2) Emissions from the pretreated fuel (without combustion or post-combustion SO_2 control) are equal to or less than the emission limits specified in paragraph (c) of this section.

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the SO_2 control system is not being operated because of malfunction or maintenance of the SO_2 control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (1) Following the performance testing procedures as described in §60.45b(c) or §60.45b(d), and following the monitoring procedures as described in §60.47b(a) or §60.47b(b) to determine SO_2 emission rate or fuel oil sulfur content; or (2) maintaining fuel records as described in §60.49b(r).

(k)(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2 emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. For facilities complying with the percent reduction standard and paragraph (k)(3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in paragraph (k) of this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(2) Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO_2 emissions limit in paragraph (k)(1) of this section.

(3) Units that are located in a noncontinental area and that combust coal, oil, or natural gas shall not discharge any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil or natural gas.

(4) As an alternative to meeting the requirements under paragraph (k)(1) of this section, modified facilities that combust coal or a mixture of coal with other fuels shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011]

§60.43b Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input, (i) If the affected facility combusts only coal, or

(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(3) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.

(4) An affected facility burning coke oven gas alone or in combination with other fuels not subject to a PM standard under §60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or SO_2 emissions is not subject to the PM limits under §60.43b(a).

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce SO_2 emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if (i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood;

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood; and

(iii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less.

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input;

(i) If the affected facility combusts only municipal-type solid waste; or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less;

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less;

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for municipal-type solid waste, or municipal-type solid waste and other fuels; and

(iv) Construction of the affected facility commenced after June 19, 1984, but on or before November 25, 1986.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.

(f) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and is subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less is exempt from the opacity standard specified in this paragraph.

(g) The PM and opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.

(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5), and (h)(6) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input,

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility not located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.30 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits in (h)(1) of this section.

(6) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.5 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits in (h)(1) of this section.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§60.44b Standard for nitrogen oxides (NOX).

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the following emission limits:

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

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO_2) heat input	
	ng/J	lb/MMBTu
(ii) Spreader stoker and fluidized bed combustion	260	0.60
(iii) Pulverized coal	300	0.70
(iv) Lignite, except (v)	260	0.60
(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace	340	0.80
(vi) Coal-derived synthetic fuels	210	0.50
(4) Duct burner used in a combined cycle system:		
(i) Natural gas and distillate oil	86	0.20
(ii) Residual oil	170	0.40

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of a limit determined by the use of the following formula:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

E_n = NO_X emission limit (expressed as NO_2), ng/J (lb/MMBtu);

EL_{go} = Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

H_{go} = Heat input from combustion of natural gas or distillate oil, J (MMBtu);

EL_{ro} = Appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/MMBtu);

H_{ro} = Heat input from combustion of residual oil, J (MMBtu);

EL_c = Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

H_c = Heat input from combustion of coal, J (MMBtu).

(c) Except as provided under paragraph (d) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, natural gas (or any combination of the three), and wood, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit for the coal, oil, natural gas (or any combination of the three), combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section. This standard does not apply to an affected facility that is subject to and in compliance with a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, natural gas (or any combination of the three).

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural

gas and/or distillate oil with a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) or less with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas, distillate oil, or a mixture of these fuels of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas, distillate oil, or a mixture of these fuels.

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts only coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a NO_X emission limit that shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as NO_X emissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific NO_X emission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, by conducting a 30-day performance test as provided in §60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The NO_X emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific NO_X emission limit will be established at the NO_X emission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing NO_X emissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_X limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the NO_X emission limit that applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on NO_X emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the NO_X emission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the NO_X emission limits of this section. The NO_X emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).) In lieu of

amending this subpart, a letter will be sent to the facility describing the facility-specific NO_X limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(h) For purposes of paragraph (i) of this section, the NO_X standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the NO_X emission limits under this section.

(l) On and after the date on which the initial performance test is completed or is required to be completed under 60.8, whichever date is first, no owner or operator of an affected facility that commenced construction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOx (expressed as NO2) in excess of the following limits:

(1) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal, oil, or natural gas (or any combination of the three), alone or with any other fuels. The affected facility is not subject to this limit if it is subject to and in compliance with a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas (or any combination of the three); or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

Where:

E_n = NO_X emission limit, (lb/MMBtu);

H_{go} = 30-day heat input from combustion of natural gas or distillate oil; and

H_r = 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of §60.48Da(i) of

subpart Da of this part, and must monitor emissions according to §60.49Da(c), (k), through (n) of subpart Da of this part.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009; 77 FR 9459, Feb. 16, 2012]

§60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The SO_2 emission standards in §60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil are allowed to exceed the limit 30 operating days per calendar year for SO_2 control system maintenance.

(b) In conducting the performance tests required under §60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential SO_2 emission rate (% P_s) and the SO_2 emission rate (E_s) pursuant to §60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the SO_2 standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(2) If only coal, only oil, or a mixture of coal and oil is combusted, the following procedures are used:

(i) The procedures in Method 19 of appendix A-7 of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS of §60.47b(a) or (b).

(ii) The percent of potential SO_2 emission rate ($\%P_s$) emitted to the atmosphere is computed using the following formula:

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

Where:

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

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

$\%R_f$ = SO_2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(3) If coal or oil is combusted with other fuels, the same procedures required in paragraph (c)(2) of this section are used, except as provided in the following:

(i) An adjusted hourly SO_2 emission rate ($E_{ho}°$) is used in Equation 19-19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate ($E_{ao}°$). The Eho° is computed using the following formula:

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

Where:

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

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

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

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

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

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

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

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

Where:

E_{hi}^{o} = Adjusted hourly SO_2 inlet rate, ng/J (lb/MMBtu); and

E_{hi} = Hourly SO_2 inlet rate, ng/J (lb/MMBtu).

(4) The owner or operator of an affected facility subject to paragraph (c)(3) of this section does not have to measure parameters E_w or X_k if the owner or operator elects to assume that X_k = 1.0. Owners or operators of affected facilities who assume X_k = 1.0 shall:

(i) Determine $\%P_s$ following the procedures in paragraph (c)(2) of this section; and

(ii) Sulfur dioxide emissions (E_s) are considered to be in compliance with SO_2 emission limits under §60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of §60.42b(d) does not have to measure parameters E_w or X_k in paragraph (c)(3) of this section if the owner or operator of the affected facility elects to measure SO_2 emission rates of the coal or oil following the fuel sampling and analysis procedures in Method 19 of appendix A-7 of this part.

(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, natural gas, or a mixture of these fuels, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a CEMS is used, or based on a daily

average if Method 6B of appendix A of this part or fuel sampling and analysis procedures under Method 19 of appendix A of this part are used.

(e) The owner or operator of an affected facility subject to §60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(f) For the initial performance test required under §60.8, compliance with the SO_2 emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for SO_2 for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating conditions and include at least one 24-hour period at full load.

(g) After the initial performance test required under §60.8, compliance with the SO_2 emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for SO_2 for 30 successive steam generating unit operating days, except as provided under paragraph (d). A separate performance test is completed at the end of each steam generating unit operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for SO_2 are calculated to show compliance with the standard.

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraph (c), of this section whether or not the minimum emissions data requirements under §60.46b are achieved. All valid emissions data, including valid SO_2 emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating $\%P_s$ and E_{ho} pursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the SO_2 control systems when oil is combusted as provided under §60.42b(i), emission data are not used to calculate $\%P_s$ or E_s under §60.42b(a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under §60.42b(i).

(j) The owner or operator of an affected facility that only combusts very low sulfur oil, natural gas, or a mixture of these fuels with any other fuels not subject to an SO_2 standard is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance in §§60.42b(d)(4), 60.42b(j), 60.42b(k)(2), and 60.42b(k)(3) (when not burning coal) shall follow the applicable procedures in §60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The PM emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_X emission standards under §60.44b apply at all times.

(b) Compliance with the PM emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the NO_X emission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the PM emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

(1) Method 3A or 3B of appendix A-2 of this part is used for gas analysis when applying Method 5 of appendix A-3 of this part or Method 17 of appendix A-6 of this part.

(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A-6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A-6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

(5) For determination of PM emissions, the oxygen (O_2) or CO_2 sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

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

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for NO_X required under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring NO_X under §60.48(b).

(1) For the initial compliance test, NO_X from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_X emission standards under §60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) Following the date on which the initial performance test is completed or is required to be completed in §60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal (except as specified under §60.46b(e)(4)) or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the NO_X emission standards in §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated for each steam

generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hr) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NO_X standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(4) Following the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_X standards in §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_X emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_X emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(5) If the owner or operator of an affected facility that combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in §60.49b(e), the requirements of §60.48b(g)(1) apply and the provisions of §60.48b(g)(2) are inapplicable.

(f) To determine compliance with the emissions limits for NO_X required by §60.44b(a)(4) or §60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under §60.8 as follows:

(i) The emissions rate (E) of NO_X shall be computed using Equation 1 in this section:

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

Where:

E = Emissions rate of NO_X from the duct burner, ng/J (lb/MMBtu) heat input;

E_{sg} = Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of this part;

H_g = Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);

H_b = Heat input rate to the duct burner, in J/hr (MMBtu/hr); and

E_g = Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part.

(ii) Method 7E of appendix A of this part or Method 320 of appendix A of part 63 shall be used to determine the NO_X concentrations. Method 3A or 3B of appendix A of this part shall be used to determine O_2 concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

(iv) Compliance with the emissions limits under §60.44b(a)(4) or §60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under §60.48b for measuring NO_X and O_2 and meet the requirements of §60.48b. The sampling site shall be located at the outlet from the steam generating unit. The NO_X emissions rate at the outlet from the steam generating unit shall constitute the NO_X emissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method or the heat input method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (incorporated by reference, see §60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of §60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of §60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in §60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

(1) Conduct an initial performance test as required under §60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_X emission standards under §60.44b using Method 7, 7A, or 7E of appendix A of this part, Method 320 of appendix A of part 63 of this chapter, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NO_X emission standards under §60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, or 7E of appendix A of this part, Method 320 of appendix A of part 63, or other approved reference methods.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the PM limit in paragraphs §60.43b(a)(4) or §60.43b(h)(5) shall follow the applicable procedures in §60.49b(r).

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

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

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

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

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

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

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

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

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

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

(ii) [Reserved]

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

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

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

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

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

(ii) For O_2 (or CO_2), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

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

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

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in §60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

[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).

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§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 L

Part 70 Operating Permit No: 073-45762-00008

[Downloaded from the eCFR on May 13, 2013]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Source: 72 FR 32759, June 13, 2007, unless otherwise noted.

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

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

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

(e) Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

(h) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

(i) Temporary boilers are not subject to this subpart.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

§ 60.41c Definitions.

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

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

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

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

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

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

Dry flue gas desulfurization technology means a SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under § 60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO_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.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Wet flue gas desulfurization technology means an SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_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 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

§ 60.42c Standard for sulfur dioxide (SO2).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_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), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_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), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

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

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

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO_2 emissions limit or the 90 percent SO_2 reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO_2 emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 50 percent (0.50) of the potential SO_2 emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO_2 reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

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

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

(3) Affected facilities located in a noncontinental area; or

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

(d) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the following:

(1) The percent of potential SO_2 emission rate or numerical SO_2 emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/h); and

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

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

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

Where:

E_s = SO_2 emission limit, expressed in ng/J or lb/MMBtu heat input;

K_a = 520 ng/J (1.2 lb/MMBtu);

K_b = 260 ng/J (0.60 lb/MMBtu);

K_c = 215 ng/J (0.50 lb/MMBtu);

H_a = Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

H_b = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

H_c = Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential SO_2 emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO_2 emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO_2 control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

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

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under § 60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(i) The SO_2 emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this

section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9462, Feb. 16, 2012]

§ 60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under § 60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO_2 emissions is not subject to the PM limit in this section.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 77 FR 9462, Feb. 16, 2012]

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

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

(b) The initial performance test required under § 60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO_2 emission limits under § 60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) of this section and § 60.8, compliance with the percent reduction requirements and SO_2 emission limits under § 60.42c is based on the average percent reduction and the average SO_2 emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO_2 emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average SO_2 emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted E_{ho} (E_{ho} o) is used in Equation 19-19 of Method 19 of appendix A of this part to compute the adjusted E_{ao} (E_{ao} o). The E_{ho} o is computed using the following formula:

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

Where:

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

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

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume E_w = 0.

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

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

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

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

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

Where:

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

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

$\%R_f$ = SO_2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the $\%P_s$, an adjusted $\%R_g$ ($\%R_g$ o) is computed from E_{ao} o from paragraph (e)(1) of this section and an adjusted average SO_2 inlet rate (E_{ai} o) using the following formula:

$$\%R_g o = 100\left(1 - \frac{E^{\circ}_{ao}}{E^{\circ}_{ai}}\right)$$

Where:

$\%R_g$ o = Adjusted $\%R_g$, in percent;

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

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

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

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

Where:

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

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

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume E_w = 0; and

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

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under § 60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under § 60.46c(d)(2).

(h) For affected facilities subject to § 60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in § 60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under § 60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under § 60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating $\%P_s$ or E_{ho} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under § 60.43c shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B of appendix A-2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A-3 of this part or 17 of appendix A-6 of this part.

(3) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F).

(6) For determination of PM emissions, an oxygen (O_2) or carbon dioxide (CO_2) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

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

(i) The O_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.

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

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

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

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

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

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

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

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under § 60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

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

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

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

(ii) [Reserved]

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

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

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

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_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 O2 (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 on a 30-day rolling average.

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under § 60.43c(e)(4) shall follow the applicable procedures under § 60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

§ 60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO_2 emission limits under § 60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations at the outlet of the SO_2 control device (or the outlet of the steam generating unit if no SO_2 control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under § 60.42c shall measure SO_2 concentrations and either O_2 or CO_2 concentrations at both the inlet and outlet of the SO_2 control device.

(b) The 1-hour average SO_2 emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.42c. Each 1-hour average SO_2 emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under § 60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities subject to the percent reduction requirements under § 60.42c, the span value of the SO_2 CEMS at the inlet to the SO_2 control device shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted, and the span value of the SO_2 CEMS at the outlet from the SO_2 control device shall be 50 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of § 60.42c, the span value of the SO_2 CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when

calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO_2 at the inlet or outlet of the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in § 3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to § 60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, as described under § 60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in § 60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from

the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in § 60.45c(a)(8).

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS “Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO2 or PM emissions and that are subject to an opacity standard in § 60.43c(c) are not required to operate a COMS if they follow the applicable procedures in § 60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in § 60.45c(c). The CEMS specified in paragraph § 60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) Owners and operators of an affected facility that is subject to an opacity standard in § 60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2 , or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and

operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(4) You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(f) An owner or operator of an affected facility that is subject to an opacity standard in § 60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section § 60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section § 60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.48c(c).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by § 60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under § 60.42c, or § 60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2 emission limits of § 60.42c, or the PM or opacity limits of § 60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator

(d) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO_2 emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO_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 a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in § 60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in § 60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in § 60.42C to use fuel certification to demonstrate compliance with the SO_2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under § 60.42c or § 60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

Attachment M

Part 70 Operating Permit No: 073-45762-00008

[Downloaded from the eCFR on December 7, 2022]

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 15 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 Table 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 Table 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 1 of § 63.7575 to demonstrate compliance with the output-based emission limits, in units of pounds per million Btu of steam output, in Table 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 (iv) of this section, but on or after October 6, 2025, you must comply with the emission limits in Table 1 to this subpart. If you operate an existing boiler or process heater, you can choose to comply with alternative limits as discussed in paragraph (a)(1)(v) of this section, but on or after October 6, 2025 you must comply with the emission limits in Table 2 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 11 or 14 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 12 or 14 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 13 or 14 to this subpart until January 31, 2016.

(iv) If you operate a new boiler or process heater, you must comply with either the emission limits in Table 1 to this subpart or the emission limits in Table 14 to this subpart until you must comply with the emission limits in Table 1.

(v) If you operate an existing boiler or process heater, you must comply with either the emission limits in Table 2 to this subpart or the emission limits in Table 15 to this subpart until you must comply with the emission limits in Table 2.

(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 Tables 11 through 15 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 Tables 11 through 15 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; 87 FR 60840, Oct. 6, 2022]

§ 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), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard. Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance stack testing, if subject to an applicable emission limit listed in Table 1 or 2 or Tables 11 through 15 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; 87 FR 60841, Oct. 6, 2022]

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 Table 1 or 2 or Tables 11 through 15 to 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 Table 1 or 2 or Tables 11 through 15 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 paragraphs (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 Table 1 or 2 or Tables 11 through 15 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.

(1) If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent than the applicable emission limit in Table 14 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 14 no later than July 29, 2016.

(2) If you are demonstrating compliance with an emission limit in Table 14 to this subpart that is less stringent 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 October 6, 2025.

(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 or 14 to this subpart, as applicable, 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; 87 FR 60841, Oct. 6, 2022]

§ 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 15 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 15 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 15).

(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 Table 1 or 2 or Tables 11 through 15 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 1 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 1 year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Table 1 or 2 or Tables 11 through 15 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) to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Table 1 or 2 or Tables 11 through 15 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; 87 FR 60842, Oct. 6, 2022]

§ 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 15 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; 87 FR 60842, Oct. 6, 2022]

§ 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 15 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 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; 87 FR 60842, Oct. 6, 2022]

§ 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 or 15 to this subpart as specified in paragraphs (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 or 15 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 to this paragraph (e)(1) 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 or 15 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.

Equation 1a to paragraph (e)(1)

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Hm) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq. 1a)}$$

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.

Equation 1b to paragraph (e)(1)

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 1b)}$$

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.

Equation 1c to paragraph (e)(1)

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Eo) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq. 1c)}$$

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 to this paragraph (e)(2) as an alternative to using Equation 1a of paragraph (e)(1) 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 or 15 to this subpart that are in pounds per million Btu of heat input.

Equation 2 to paragraph (e)(2)

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sm \times Cfi) \div \sum_{i=1}^{n} (Sm \times Cfi) \qquad \text{(Eq. 2)}$$

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 or 15 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 to this paragraph (j)(1).

Equation 6 to paragraph (j)(1)

$$En = \sum_{i=1}^{n} (ELi \times Hi) \div \sum_{i=1}^{n} Hi \qquad \text{(Eq. 6)}$$

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 or 15 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; 87 FR 60843, Oct. 6, 2022]

§ 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 Table 1 or 2 or Tables 11 through 15 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 (O_2) (or carbon dioxide (CO_2)) according to the procedures in paragraphs (a)(1) through (6) of this section.

(1) Install the CO CEMS including an O_2 (or CO_2) analyzer by the compliance date specified in § 63.7495. The CO and O_2 (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 determine compliance with the CO emissions limit using a CO_2 analyzer as the diluent monitor. If a CO_2 analyzer is used as the diluent monitor, EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, for the fuel type(s) being burned in the unit and EPA Method 19 equations in 40 CFR part 60, appendix A-7, must be used to calculate the emissions corrected to 3 percent O_2 using the measured CO_2 percentage, and must also take into account that the 3 percent oxygen correction is to be done on a dry basis. The equations used to calculate the emissions, must also account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc. The methodology used to calculate the CO emissions and the methodology used to account for any CO_2 being added to, or removed from the emissions gas stream shall be detailed and approved in the site-specific monitoring plan developed according to § 63.7505(d).

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Table 1 or 2 or Tables 11 through 15 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 this paragraph (a). 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 this paragraph (a) must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Table 1 or 2 or Tables 11 through 15 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 collect emission data for CO concurrently using both the CO CEMS and Method 10, 10A, or 10B at 40 CFR part 60, appendix A-4. The relative accuracy testing must be conducted 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 this paragraph (a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Table 1 or 2 or Tables 11 through 15 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, if needed, 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 Table 1 or 2 or Tables 11 through 15 to 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 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 Table 1 or 2 or Tables 11 through 15 to 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.

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§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by § 63.7510(a)(2). 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.

$$Mercuryinput = \sum_{i=1}^{n} (HGi \times Qi) \qquad \text{(Eq. 8)}$$

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.

$$\bar{x} = \frac{1}{n}\sum_{t=1}^{n} X_1 \bar{y} = \frac{1}{n}\sum_{t=1}^{n} Y_1 \qquad \text{(Eq. 10)}$$

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.

$$O_h = \frac{1}{n}\sum_{t=1}^{n} X_1 \qquad \text{(Eq. 13)}$$

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.

$$30-\text{day} = \frac{\sum_{i=1}^{n} Hpv}{n} \qquad \text{(Eq. 14)}$$

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 Table 1 or 2 or Tables 11 through 15 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 in 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. 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.

$$P90 = mean + (SD \times t) \qquad \text{(Eq. 15)}$$

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.

$$HCl = \sum_{i=1}^{n} (Ci90 \times Qi \times 1.028) \qquad \text{(Eq. 16)}$$

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.

$$Mercury = \sum_{i=1}^{n} (Hgi90 \times Qi) \qquad \text{(Eq. 17)}$$

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 Table 1 or 2 or Tables 11 through 15 to this subpart, you must meet the work practice standard according to Table 3 to this subpart. During startup and shutdown, you must only follow the work practice standards according to items 5 and 6 of Table 3 to 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; 87 FR 60845, Oct. 6, 2022]

§ 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 or 15 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 *https://www.epa.gov/ttn/atw/boiler/boilerpg.html*.

(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (*i.e.,* fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.

(1) The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

(2) Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).

(3) Document all uses of energy from the affected boiler. Use the most recent data available.

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) For all points included in calculating emissions credits, the owner or operator shall:

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

$$ECredits = \left(\sum_{i=1}^{n} EIS_{iactual} \right) \div EI_{baseline} \qquad \text{(Eq. 19)}$$

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 in paragraph (f) of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 or 15 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 paragraph (f) 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 or 15 to this subpart.

Equation 20 to paragraph (f)

$$E_{adj} = E_m \times (1 - ECredits) \quad \text{(Eq. 20)}$$

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 to paragraph (c)(3)(i) of this section 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; 87 FR 60845, Oct. 6, 2022]

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 15 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 Table 1 or 2 or Tables 11 through 15 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 Table 1 or 2 or Tables 11 through 15 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 (PM CEMS only), 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 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 Table 1 or 2 or Tables 11 through 15 to 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 15 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; 87 FR 60846, Oct. 6, 2022]

§ 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, or no later than 120 days after the source becomes subject to this subpart, whichever is later.

(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. For a new or reconstructed affected source that has reclassified to major source status, you must submit an Initial Notification not later 120 days after the source becomes subject to this subpart.

(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 Table 1 or 2 or Tables 11 through 15 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; 85 FR 73913, Nov. 19, 2020; 85 FR 84262, Dec. 28, 2020; 87 FR 60846, Oct. 6, 2022]

§ 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 Table 1 or 2 or Tables 11 through 15 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 15 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; 87 FR 60846, Oct. 6, 2022]

§ 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.

12-month rolling average means the arithmetic mean of the previous 12 months of valid fuel analysis data. The 12 months 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 mercury concentration of 40 micrograms/cubic meters of gas.

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, 2, 14, or 15 to 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 1 to this definition. In the case of boilers supplying steam to one or more common headers, S_1, S_2, and $MW_{(3)}$ for each boiler would be calculated based on its (steam energy) contribution (fraction of total steam energy) to the common header.

Equation 1 to the definition *Steam Output*

$$SO_M = S_1 + S_2 + (MW_{(3)} \; x \; CFn) \qquad \text{(Eq. 1)}$$

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 paragraph (2) of this definition, 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; 87 FR 60846, Oct. 6, 2022]

Table 1 to Subpart DDDDD of Part 63 - Emission Limits for New or Reconstructed Boilers and Process Heaters [c]

As stated in § 63.7500, you must comply with the following applicable emission limits:

Table 1 to Subpart DDDDD of Part 63 - Emission Limits for New or Reconstructed Boilers and Process Heaters [c]

[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**
1. Units in all subcategories designed to burn solid fuel	a. HCl	2.1E-04[a] lb per MMBtu of heat input	2.9E-04[a] lb per MMBtu of steam output or 2.7E-03[a] lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E-07[a] lb per MMBtu of heat input	8.7E-07[a] lb per MMBtu of steam output or 1.1E-05[a] lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
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.

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
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)	590 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)	6.1E-01 lb per MMBtu of steam output or 6.5 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 (2.6E-05 lb per MMBtu of heat input)	1.4E-02 lb per MMBtu of steam output or 1.9E-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.

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
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	4.3E-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 (5.0E-03 lb per MMBtu of heat input)	3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (5.2E-03 lb per MMBtu of steam output or 7.0E-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)	130 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)	1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.1E-03 lb per MMBtu of heat input; or (8.4E-06[a] lb per MMBtu of heat input)	5.0E-03 lb per MMBtu of steam output or 5.8E-02 lb per MWh; or (1.1E-05[a] lb per MMBtu of steam output or 1.2E-04[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)	220 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)	0.18 lb per MMBtu of steam output or 2.5 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 (8.0E-03 lb per MMBtu of heat input)	3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (8.1E-03 lb per MMBtu of steam output or 1.2E-01 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
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)	2.5E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)	3.4E-03 lb per MMBtu of steam output or 3.5E-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)	1.1E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	2.0E-02 lb per MMBtu of steam output or 1.6E-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)	180 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)	0.22 lb per MMBtu of steam output or 2.0 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	1.5E-04[a] lb per MMBtu of heat input	1.7E-04[a] lb per MMBtu of steam output or 2.1E-03[a] 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
	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)	1.9E-03 lb per MMBtu of heat input; or (6.1E-06[a] lb per MMBtu of heat input)	2.1E-03 lb per MMBtu of steam output or 2.7E-02 lb per MWh; or (6.7E-6[a] lb per MMBtu of steam output or 8.5E-5[a] lb per MWh)	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03[a] lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1.2E-03[a] lb per MMBtu of steam output or 1.6E-02[a] lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	7.3E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	1.3E-02 lb per MMBtu of steam output or 7.6E-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 Table 11, 12, or 13 to this subpart until January 31, 2016. On and after January 31, 2016, but before October 6, 2025 you may comply with the emission limits in Table 14 to this subpart. On and after October 6, 2025 you must comply with the emission limits in this Table 1.

[d] An owner or operator may determine compliance with the carbon monoxide emissions limit using CO_2 as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, 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 methodology 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. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[87 FR 60847, Oct. 6, 2022]

Table 2 to Subpart DDDDD of Part 63 - Emission Limits for Existing Boilers and Process Heaters [d]

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	2.0E-02 lb per MMBtu of heat input	2.3E-02 lb per MMBtu of steam output or 0.26 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	5.4E-06 lb per MMBtu of heat input	6.2E-06 lb per MMBtu of steam output or 6.9E-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)	3.9E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input)	4.1E-02 lb per MMBtu of steam output or 4.8E-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)	150 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 1.6 lb per MWh; 3-run average	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3-percent oxygen,[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.
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)	1,100 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)	1.1 lb per MMBtu of steam output or 13 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.4E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	4.0E-02 lb per MMBtu of steam output or 4.8E-01 lb per MWh; or (2.4E-04 lb per MMBtu of steam output or 2.8E-03 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 (5.0E-03 lb per MMBtu of heat input)	3.7E-01 lb per MMBtu of steam output or 4.5 lb per MWh; or (5.9E-03 lb per MMBtu of steam output or 7.0E-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)	210 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)	2.1E-01 lb per MMBtu of steam output or 2.3 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)	7.4E-03 lb per MMBtu of heat input; or (6.4E-05 lb per MMBtu of heat input)	9.2E-03 lb per MMBtu of steam output or 0.11 lb per MWh; or (8.0E-05 lb per MMBtu of steam output or 9.0E-04 lb per MWh)	Collect a minimum of 1 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen,[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)	4.1E-02 lb per MMBtu of heat input; or (8.0E-03 lb per MMBtu of heat input)	4.2E-02 lb per MMBtu of steam output or 5.8E-01 lb per MWh; or (8.1E-03 lb per MMBtu of steam output or 0.12 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)	1.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input)	2.5E-01 lb per MMBtu of steam output or 2.6 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.

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 . . .
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.
	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	7.3E-07 lb per MMBtu of heat input	8.8E-07 lb per MMBtu of steam output or 1.1E-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)	5.9E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	7.2E-02 lb per MMBtu of steam output or 8.2E-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.

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)	7.9E-03 lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03 lb per MMBtu of steam output or 1.1E-01 lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.2E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.7E-01 lb per MMBtu of steam output or 3.1 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 2 dscm.
	d. Filterable PM (or TSM)	7.3E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input)	1.3E-02 lb per MMBtu of steam output or 7.6E-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 determine compliance with the carbon monoxide emissions limit be determined using CO_2 as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, 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 methodology 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. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[d] Before October 6, 2025 you may comply with the emission limits in Table 15 to this subpart. On and after October 6, 2025], you must comply with the emission limits in this Table 2.

[87 FR 60849, Oct. 6, 2022]

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.

If your unit is . . .	You must meet the following . . .
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.
	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 15 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.

If your unit is . . .	You must meet the following . . .
	c. You have the option of complying using either of the following work practice standards. (1) If you choose to comply using paragraph (1) of the definition 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 paragraph (2) of the definition 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.
6. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or Tables 11 through 15 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.

If your unit is . . .	You must meet the following . . .
	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).

[87 FR 60852, Oct. 6, 2022]

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 numerical emission limit under Table 1, 2, 11, 12, 13, 14, or 15 of this subpart 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
	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).

When complying with a numerical emission limit under Table 1, 2, 11, 12, 13, 14, or 15 of this subpart using . . .	You must meet these operating limits. . .
	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, as amended at 87 FR 60853, Oct. 6, 2022]

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.

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 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.
	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.

To conduct a performance test for the following pollutant . . .	You must. . .	Using, as appropriate . . .
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 EPA 1631 or EPA 1631E or ASTM D6323[a] (for solid), or EPA 821-R-01-013 (for liquid or solid), or ASTM D4177[a] (for liquid), or ASTM D4057[a] (for liquid), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B[a] (for solid samples), 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[a], 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[a] (for solid samples), or EPA SW-846-7470A[a] or EPA SW-846-7471B[a] (for liquid samples), or EPA 821-R-01-013[a] (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[a], 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[a], or ASTM D240[a], or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent.
	f. Measure 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.

[83 FR 56725, Nov. 14, 2018]

Table 7 to Subpart DDDDD of Part 63 - Establishing Operating Limits [ab]

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 by computing the hourly averages using all of the 15-minute readings taken during each performance test.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				(c) Determine the highest hourly average opacity reading measured during the test run demonstrating compliance with the PM (or TSM) emission limitation.
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.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
	c. Alternative Maximum SO_2 emission rate	i. Establish a site-specific maximum SO_2 emission 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_2 emission rate is equal to the highest hourly average SO_2 emission rate measured during the most recent HCl performance tests.
3. Mercury	a. Activated carbon injection	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b)	(1) Data from the activated carbon rate monitors and mercury performance test	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction, 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.

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				(c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test	a. Boiler or process heater operating load	i. Establish a unit specific limit for maximum operating load according to § 63.7520(c)	(1) Data from the operating load monitors or from steam generation monitors	(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test.
				(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the 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. For maximum operating load, if you conduct multiple performance tests, you must set the maximum operating load at the lower of the maximum values established during the performance tests.

[87 FR 60853, Oct. 6, 2022]

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

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
	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
	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 15 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 16, 17, and/or 18 in § 63.7530.

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen analyzer system according to § 63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a)(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; 87 FR 60855, Oct. 6, 2022]

Table 9 to Subpart DDDDD of Part 63 - Reporting Requirements

As stated in § 63.7550, you must comply with the following requirements for reports:

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.7550(c)(1) through (5); and	Semiannually, annually, biennially, or every 5 years according to the requirements in § 63.7550(b).
	b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards 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	

You must submit a(n)	The report must contain . . .	You must submit the report . . .
	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.
§ 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).

Citation	Subject	Applies to subpart DDDDD
§ 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.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.
§ 63.8(e)	Performance evaluation of a CMS	Yes.
§ 63.8(f)	Use of an alternative monitoring method.	Yes.
§ 63.8(g)	Reduction of monitoring data	Yes.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1)	Recordkeeping and Reporting Requirements	Yes.

Citation	Subject	Applies to subpart DDDDD
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	Yes.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during startup, shutdown, or malfunction	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§ 63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§ 63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(10) and (11)	Recording nature and cause of malfunctions, and corrective actions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Use of startup, shutdown, and malfunction plan	No.
§ 63.10(d)(1) and (2)	General reporting requirements	Yes.
§ 63.10(d)(3)	Reporting opacity or visible emission observation results	No.
§ 63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No. See § 63.7550(c)(11) for malfunction reporting requirements.
§ 63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.

Citation	Subject	Applies to subpart DDDDD
§ 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.
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.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
6. 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	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	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

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Mercury.	4.8E-07[a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
17. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
18. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-03[a] lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run
19. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 4 dscm per run
20. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm.
	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 determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, 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 methodology 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. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[87 FR 60855, Oct. 6, 2022]

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.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen,[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.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids	a. CO (or CEMS)	260 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen,[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.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
12. Fuel cell units designed to burn biomass/bio-based solids	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen,[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.
	b. Mercury	4.8E-07[a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 2 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E-03[a] lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen	1 hr minimum sampling time.

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. 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 determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, 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 methodology 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. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[87 FR 60857, Oct. 6, 2022]

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.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
2. 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.
	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.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	3.2E-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.
	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.

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	4.9E-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.
	b. Filterable PM (or TSM)	1.3E-03 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)	Collect a minimum of 3 dscm per run.
15. Units designed to burn light liquid fuel	a. CO (or CEMS)	130[a] ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen,[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,[c] 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 determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, 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 methodology 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. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[87 FR 60859, Oct. 6, 2022]

Table 14 to Subpart DDDDD of Part 63 - Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters [c]

As stated in § 63.7500, you may continue to comply with the following applicable emission limits until October 6, 2025:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.28 lb per MWh	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E-07[a] lb per MMBtu of heat input	8.7E-07[a] lb per MMBtu of steam output or 1.1E-05[a] lb per MWh	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 4 dscm.
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.

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 . . .
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.
	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.

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 . . .
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 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[a] 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[a] lb per MMBtu of steam output or 1.1E-03[a] lb per MWh)	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E-03[a] lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)	1.2E-03[a] lb per MMBtu of steam output or 1.6E-02[a] lb per MWh; or (3.2E-05 lb per MMBtu of steam output or 4.0E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	2.5E-02 lb per MMBtu of steam output or 3.2E-01 lb per MWh; or (9.4E-04 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[c] If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before April 1, 2013, you may comply with the emission limits in Table 11, 12, or 13 to this subpart until January 31, 2016. On and after January 31, 2016, but before October 6, 2025 you may comply with the emission limits in this Table 14. On and after October 6, 2025, you must comply with the emission limits in Table 1 to this subpart.

[d] An owner or operator may determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, 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 methodology 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. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[87 FR 60860, Oct. 6, 2022]

Table 15 to Subpart DDDDD of Part 63 - Alternative Emission Limits for Existing Boilers and Process Heaters[d]

As stated in § 63.7500, you may continue to comply with following emission limits until October 6, 2025:

[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.

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
5. Fluidized bed units designed to burn coal/solid fossil fuel	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3-percent oxygen,[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.
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.

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)	1.1E-01 lb per MMBtu of heat input; or (1.2E-03 lb per MMBtu of heat input)	1.4E-01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E-03 lb per MMBtu of steam output or 1.7E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solid	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen,[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.

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 . . .
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.
	b. Filterable PM (or TSM)	4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input)	5.5E-01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E-04 lb per MMBtu of steam output or 6.3E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	1.1E-03 lb per MMBtu of heat input	1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E-06 lb per MMBtu of heat input	2.5E-06 lb per MMBtu of steam output or 2.8E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784[b] collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	6.2E-02 lb per MMBtu of heat input; or (2.0E-04 lb per MMBtu of heat input)	7.5E-02 lb per MMBtu of steam output or 8.6E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.13 lb per MMBtu of steam output or 1.4 lb per MWh	1 hr minimum sampling time.

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)	7.9E-03 lb per MMBtu of heat input; or (6.2E-05 lb per MMBtu of heat input)	9.6E-03 lb per MMBtu of steam output or 1.1E-01 lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average based on stack test	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.7E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)	3.3E-01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh)	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases	a. CO	130 ppm by volume on a dry basis corrected to 3-percent oxygen	0.16 lb per MMBtu of steam output or 1.0 lb per MWh	1 hr minimum sampling time.
	b. HCl	1.7E-03 lb per MMBtu of heat input	2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E-06 lb per MMBtu of heat input	1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[b] collect a minimum of 2 dscm.
	d. Filterable PM (or TSM)	6.7E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input)	1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)	Collect a minimum of three 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 determine compliance with the carbon monoxide emissions limit using carbon dioxide as a diluent correction in place of oxygen as described in § 63.7525(a)(1). EPA Method 19 F-factors in 40 CFR part 60, appendix A-7, and EPA Method 19 equations in 40 CFR part 60, appendix A-7, 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 methodology 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. This methodology must be detailed in the site-specific monitoring plan developed according to § 63.7505(d).

[d] Before October 6, 2025 you may comply with the emission limits in this Table 15. On and after October 6, 2025, you must comply with the emission limits in Table 2 to this subpart.

[87 FR 60863, Oct. 6, 2022]

Attachment N

Part 70 Operating Permit No: 073-45762-00008

[Downloaded from the eCFR on March 11, 2022]

Electronic Code of Federal Regulations

Title 40: Protection of Environment

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

Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

Source: 69 FR 10537, Mar. 5, 2004, unless otherwise noted.

What This Subpart Covers

§ 63.6080 What is the purpose of subpart YYYY?

Subpart YYYY establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitations.

§ 63.6085 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary combustion turbine located at a major source of HAP emissions.

(a) Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function, although it may be mounted on a vehicle for portability or transportability. Stationary combustion turbines covered by this subpart include simple cycle stationary combustion turbines, regenerative/recuperative cycle stationary combustion turbines, cogeneration cycle stationary combustion turbines, and combined cycle stationary combustion turbines. Stationary combustion turbines subject to this subpart do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

(b) A major source of HAP emissions is a contiguous site under common control 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.

§ 63.6090 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 combustion turbine located at a major source of HAP emissions.

(1) ***Existing stationary combustion turbine.*** A stationary combustion turbine is existing if you commenced construction or reconstruction of the stationary combustion turbine on or before January 14, 2003. A change in ownership of an existing stationary combustion turbine does not make that stationary combustion turbine a new or reconstructed stationary combustion turbine.

(2) ***New stationary combustion turbine.*** A stationary combustion turbine is new if you commenced construction of the stationary combustion turbine after January 14, 2003.

(3) ***Reconstructed stationary combustion turbine.*** A stationary combustion turbine is reconstructed if you meet the definition of reconstruction in § 63.2 of subpart A of this part and reconstruction is commenced after January 14, 2003.

(b) ***Subcategories with limited requirements.***

(1) A new or reconstructed stationary combustion turbine located at a major source which meets either of the following criteria does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6145(d):

(i) The stationary combustion turbine is an emergency stationary combustion turbine; or

(ii) The stationary combustion turbine is located on the North Slope of Alaska.

(2) A stationary combustion turbine which burns landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or a stationary combustion turbine where gasified municipal solid waste (MSW) is used to generate 10 percent or more of the gross heat input on an annual basis does not have to meet the requirements of this subpart except for:

(i) The initial notification requirements of § 63.6145(d); and

(ii) Additional monitoring and reporting requirements as provided in §§ 63.6125(c) and 63.6150.

(3) An existing, new, or reconstructed stationary combustion turbine with a rated peak power output of less than 1.0 megawatt (MW) at International Organization for Standardization (ISO) standard day conditions, which is located at a major source, does not have to meet the requirements of this subpart and of subpart A of this part. This determination applies to the capacities of individual combustion turbines, whether or not an aggregated group of combustion turbines has a common add-on air pollution control device. No initial notification is necessary, even if the unit appears to be subject to other requirements for initial notification. For example, a 0.75 MW emergency turbine would not have to submit an initial notification.

(4) Existing stationary combustion turbines in all subcategories do not have to meet the requirements of this subpart and of subpart A of this part. No initial notification is necessary for any existing stationary combustion turbine, even if a new or reconstructed turbine in the same category would require an initial notification.

(5) Combustion turbine engine test cells/stands do not have to meet the requirements of this subpart but may have to meet the requirements of subpart A of this part if subject to another subpart. No initial notification is necessary, even if the unit appears to be subject to other requirements for initial notification.

§ 63.6092 Are duct burners and waste heat recovery units covered by subpart YYYY?

No, duct burners and waste heat recovery units are considered steam generating units and are not covered under this subpart. In some cases, it may be difficult to separately monitor emissions from the turbine and duct burner, so sources are allowed to meet the required emission limitations with their duct burners in operation.

§ 63.6095 When do I have to comply with this subpart?

(a) ***Affected sources.***

(1) If you start up a new or reconstructed stationary combustion turbine which is a lean premix oil-fired stationary combustion turbine or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart on or before March 5, 2004, you must comply with the emissions limitations and operating limitations in this subpart no later than March 5, 2004.

(2) If you start up a new or reconstructed stationary combustion turbine which is a lean premix oil-fired stationary combustion turbine or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart after March 5, 2004, you must comply with the emissions limitations and operating limitations in this subpart upon startup of your affected source.

(3) If you start up a new or reconstructed stationary combustion turbine which is a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart on or before March 9, 2022, you must comply with the emissions limitations and operating limitations in this subpart no later than March 9, 2022.

(4) If you start up a new or reconstructed stationary combustion turbine which is a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart after March 9, 2022, you must comply with the emissions limitations and operating limitations in this subpart upon startup of your affected source.

(b) ***Area sources that become major sources.*** If your new or reconstructed stationary combustion turbine is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, it must be in compliance with any applicable requirements of this subpart when it becomes a major source.

(c) You must meet the notification requirements in § 63.6145 according to the schedule in § 63.6145 and in 40 CFR part 63, subpart A.

[69 FR 10537, Mar. 5, 2004, as amended at 69 FR 51188, Aug. 18, 2004; 87 FR 13192, Mar. 9, 2022]

Emission and Operating Limitations

§ 63.6100 What emission and operating limitations must I meet?

For each new or reconstructed stationary combustion turbine which is a lean premix gas-fired stationary combustion turbine, a lean premix oil-fired stationary combustion turbine, a diffusion flame gas-fired stationary combustion turbine, or a diffusion flame oil-fired stationary combustion turbine as defined by this subpart, you must comply with the emission limitations and operating limitations in Table 1 and Table 2 of this subpart.

General Compliance Requirements

§ 63.6105 What are my general requirements for complying with this subpart?

(a) Before September 8, 2020, you must be in compliance with the emission limitations and operating limitations which apply to you at all times except during startup, shutdown, and malfunctions. After September 8, 2020, you must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart which apply to you at all times.

(b) Before September 8, 2020, if you must comply with emission and operating limitations, you must operate and maintain your stationary combustion turbine, oxidation catalyst emission control device or other air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(c) After September 8, 2020, at all times, the owner or operator 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 the owner or operator to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether a source is operating in compliance with operation and maintenance requirements 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.

[85 FR 13539, Mar. 9, 2020]

Testing and Initial Compliance Requirements

§ 63.6110 By what date must I conduct the initial performance tests or other initial compliance demonstrations?

(a) You must conduct the initial performance tests or other initial compliance demonstrations in Table 4 of this subpart that apply to you within 180 calendar days after the compliance date that is specified for your stationary combustion turbine in § 63.6095 and according to the provisions in § 63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test to determine outlet formaldehyde concentration on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (b)(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.

§ 63.6115 When must I conduct subsequent performance tests?

Subsequent performance tests must be performed on an annual basis as specified in Table 3 of this subpart.

§ 63.6120 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Table 3 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements in Table 3 of this subpart. Before September 8, 2020, each performance test must be conducted according to the requirements of the General Provisions at § 63.7(e)(1).

(c) Performance tests must be conducted at high load, defined as 100 percent plus or minus 10 percent. Before September 8, 2020, do not conduct performance tests or compliance evaluations during periods of startup, shutdown, or malfunction. After September 8, 2020, performance tests shall be conducted under such conditions based on representative performance of the affected source for the period being tested. Representative conditions exclude periods of startup and shutdown. The owner or operator may not conduct performance tests during periods of malfunction. The owner or operator must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that such conditions represent normal operation. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(d) You must conduct three separate test runs for each performance test, and each test run must last at least 1 hour.

(e) If your stationary combustion turbine is not equipped with an oxidation catalyst, you must petition the Administrator for operating limitations that you will monitor to demonstrate compliance with the formaldehyde emission limitation in Table 1. You must measure these operating parameters during the initial performance test and continuously monitor thereafter. Alternatively, you may petition the Administrator for approval of no additional operating limitations. If you submit a petition under this section, you must not conduct the initial performance test until after the petition has been approved or disapproved by the Administrator.

(f) If your stationary combustion turbine is not equipped with an oxidation catalyst and you petition the Administrator for approval of additional operating limitations to demonstrate compliance with the formaldehyde emission limitation in Table 1, your petition must include the following information described in paragraphs (f)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as additional 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.

(g) If you petition the Administrator for approval of no additional operating limitations, your petition must include the information described in paragraphs (g)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary combustion turbine 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 why establishing limitations on the parameters is not possible;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of why you could not establish upper and/or lower values for the parameters which would establish limits on the parameters as operating limitations;

(5) For the parameters which could change in such a way as to increase HAP emissions, 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, unreasonable or unnecessary to adopt the parameters as operating limitations.

[69 FR 10537, Mar. 5, 2004, as amended at 85 FR 13539, Mar. 9, 2020]

§ 63.6125 What are my monitor installation, operation, and maintenance requirements?

(a) If you are operating a stationary combustion turbine that is required to comply with the formaldehyde emission limitation and you use an oxidation catalyst emission control device, you must monitor on a continuous basis your catalyst inlet temperature in order to comply with the operating limitations in Table 2 and as specified in Table 5 of this subpart.

(b) If you are operating a stationary combustion turbine that is required to comply with the formaldehyde emission limitation and you are not using an oxidation catalyst, you must continuously monitor any parameters specified in your approved petition to the Administrator, in order to comply with the operating limitations in Table 2 and as specified in Table 5 of this subpart.

(c) If you are operating a stationary combustion turbine which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or a stationary combustion turbine where gasified MSW is used to generate 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 turbine in a manner which minimizes HAP emissions.

(d) If you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must monitor and record your distillate oil usage daily for all new and existing stationary combustion turbines located at the major source with a non-resettable hour meter to measure the number of hours that distillate oil is fired.

(e) After September 8, 2020, if you are required to use a continuous monitoring system (CMS), you must develop and implement a CMS quality control program that included written procedures for CMS according to § 63.8(d)(1) through (2). You must keep these written procedures on record for the life of the affected source or until the affected source is no longer subject to the provisions of this part, to be made available for inspection, upon request, by the Administrator. If the performance evaluation plan is revised, the owner or operator shall keep previous (*i.e.,* superseded) versions of the performance evaluation plan on record to be made available for inspection, upon request, by the Administrator, for a period of 5 years after each revision to the plan. The program of corrective action should be included in the plan required under § 63.8(d)(2).

[69 FR 10537, Mar. 5, 2004, as amended at 85 FR 13539, Mar. 9, 2020]

§ 63.6130 How do I demonstrate initial compliance with the emission and operating limitations?

(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 4 of this subpart.

(b) You must submit the Notification of Compliance Status containing results of the initial compliance demonstration according to the requirements in § 63.6145(f).

Continuous Compliance Requirements

§ 63.6135 How do I monitor and collect data to demonstrate continuous compliance?

(a) Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), you must conduct all parametric monitoring at all times the stationary combustion turbine is operating.

(b) Do not use data recorded during monitor malfunctions, associated repairs, and required quality assurance or quality control activities for meeting the requirements of this subpart, including data averages and calculations. You must use all the data collected during all other periods in assessing the performance of the control device or in assessing emissions from the new or reconstructed stationary combustion turbine.

§ 63.6140 How do I demonstrate continuous compliance with the emission and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Table 1 and Table 2 of this subpart according to methods specified in Table 5 of this subpart.

(b) You must report each instance in which you did not meet each emission imitation or operating limitation. You must also report each instance in which you did not meet the requirements in Table 7 of 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 § 63.6150.

(c) Before September 8, 2020, consistent with §§ 63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, and malfunction are not violations if you have operated your stationary combustion turbine in accordance with § 63.6(e)(1)(i).

[69 FR 10537, Mar. 5, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 85 FR 13539, Mar. 9, 2020]

Notifications, Reports, and Records

§ 63.6145 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you start up your new or reconstructed stationary combustion turbine before March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after March 5, 2004, or no later than 120 days after the source becomes subject to this subpart, whichever is later.

(c) As specified in § 63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with § 63.6090(b), your notification must include the information in §

63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).

(e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in § 63.7(b)(1).

(f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

[69 FR 10537, Mar, 5, 2004, as amended at 85 FR 73911, Nov. 19, 2020]

§ 63.6150 What reports must I submit and when?

(a) ***Compliance report.*** Anyone who owns or operates a stationary combustion turbine which must meet the emission limitation for formaldehyde must submit a semiannual compliance report according to Table 6 of this subpart. The semiannual compliance report must contain the information described in paragraphs (a)(1) through (5) of this section. The semiannual compliance report, including the excess emissions and monitoring system performance reports of § 63.10(e)(3), must be submitted by the dates specified in paragraphs (b)(1) through (5) of this section, unless the Administrator has approved a different schedule. After September 8, 2020, or once the reporting template has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website for 180 days, whichever date is later, you must submit all subsequent reports to the EPA following the procedure specified in paragraph (g) 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) Before September 8, 2020, for each deviation from an emission limitation, the compliance report must contain the information in paragraphs (a)(4)(i) through (iii) of this section.

(i) The total operating time of each stationary combustion turbine during the reporting period.

(ii) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(iii) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks).

(5) After September 8, 2020, report each deviation in the semiannual compliance report. Report the information specified in paragraphs (a)(5)(i) through (iv) of this section.

(i) Report the number of deviations. For each instance, report the start date, start time, duration, and cause of each deviation, and the corrective action taken.

(ii) For each deviation, the report must include a list of the affected sources or equipment, an estimate of the quantity of each regulated pollutant emitted over any emission limit, a description of the method used to estimate the emissions.

(iii) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks), as applicable, and the corrective action taken.

(iv) Report the total operating time of the affected source during the reporting period.

(b) Dates of submittal for the semiannual compliance report are provided in (b)(1) through (b)(5) of this section.

(1) The first semiannual compliance report must cover the period beginning on the compliance date specified in § 63.6095 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 specified in § 63.6095.

(2) The first semiannual 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 in § 63.6095.

(3) Each subsequent semiannual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent semiannual 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 combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) If you are operating as a stationary combustion turbine which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or a stationary combustion turbine where gasified MSW is used to generate 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 6 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (d)(1) through (5) of this section. You must report the data specified in (c)(1) through (3) of this section. After September 8, 2020, you must submit all subsequent reports to the EPA following the procedure specified in paragraph (g) 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, digester gas, or gasified MSW 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.

(d) Dates of submittal for the annual report are provided in (d)(1) through (d)(5) of this section.

(1) The first annual report must cover the period beginning on the compliance date specified in § 63.6095 and ending on December 31.

(2) The first annual report must be postmarked or delivered no later than January 31.

(3) Each subsequent annual report must cover the annual reporting period from January 1 through December 31.

(4) Each subsequent annual report must be postmarked or delivered no later than January 31.

(5) For each stationary combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual 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 (d)(1) through (4) of this section.

(e) If you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must submit an annual report according to Table 6 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (d)(1) through (5) of this section. You must report the data specified in (e)(1) through (3) of this section. After September 8, 2020, you must submit all subsequent reports to the EPA following the procedure specified in paragraph (g) of this section.

(1) The number of hours distillate oil was fired by each new or existing stationary combustion turbine during the reporting period.

(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.

(f) ***Performance test report.*** After September 8, 2020, within 60 days after the date of completing each performance test required by this subpart, you must submit the results of the performance test (as specified in § 63.6145(f)) following the procedures specified in paragraphs (f)(1) through (3) of this section.

(1) ***Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.*** Submit the results of the performance test to the EPA via the CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The data must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website.

(2) ***Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.*** The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(3) ***Confidential business information (CBI).*** If you claim some of the information submitted under paragraph (f)(1) of this section is CBI, you must submit a complete file, including information claimed to be CBI, to the EPA. The file must be 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 website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in paragraph (f)(1) of this section.

(g) If you are required to submit reports following the procedure specified in this paragraph, you must submit reports to the EPA via CEDRI, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). You must use the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/compliance-and-emissions-data-reporting-interface-cedri*) for this subpart. The date report templates become available will be listed on the CEDRI website. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. If you claim some of the information required to be submitted via CEDRI is CBI, submit a complete report, including information claimed to be CBI, to the EPA. The report must be generated using the appropriate form on the CEDRI website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(h) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with the reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (h)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) Measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(i) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with the reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (i)(1) through (5) of this section.

(1) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the force majeure event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(iii) Measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

[69 FR 10537, Mar. 5, 2004, as amended at 85 FR 13539, Mar. 9, 2020]

§ 63.6155 What records must I keep?

(a) You must keep the records as described in paragraphs (a)(1) through (7) 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 requirements in § 63.10(b)(2)(xiv).

(2) Records of performance tests and performance evaluations as required in § 63.10(b)(2)(viii).

(3) Before September 8, 2020, records of the occurrence and duration of each startup, shutdown, or malfunction as required in § 63.10(b)(2)(i).

(4) Before September 8, 2020, records of the occurrence and duration of each malfunction of the air pollution control equipment, if applicable, as required in § 63.10(b)(2)(ii).

(5) Records of all maintenance on the air pollution control equipment as required in § 63.10(b)(2)(iii).

(6) After September 8, 2020, records of the date, time, and duration of each startup period, recording the periods when the affected source was subject to the standard applicable to startup.

(7) After September 8, 2020, keep records as follows.

(i) Record the number of deviations. For each deviation, record the date, time, cause, and duration of the deviation.

(ii) For each deviation, record and retain a list of the affected sources or equipment, an estimate of the quantity of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions.

(iii) Record actions taken to minimize emissions in accordance with § 63.6105(c), and any corrective actions taken to return the affected unit to its normal or usual manner of operation.

(b) If you are operating a stationary combustion turbine which fires landfill gas, digester gas or gasified MSW equivalent to 10 percent or more of the gross heat input on an annual basis, or if you are operating a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source, you must keep the records of your daily fuel usage monitors.

(c) You must keep the records required in Table 5 of this subpart to show continuous compliance with each operating limitation that applies to you.

(d) Any records required to be maintained by this part that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

[69 FR 10537, Mar. 5, 2004, as amended at 85 FR 13541, Mar. 9, 2020]

§ 63.6160 In what form and how long must I keep my records?

(a) You must maintain all applicable records in such a manner that they can be readily accessed and are suitable for inspection 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 retain your records of the most recent 2 years on site or your records must be accessible on site. Your records of the remaining 3 years may be retained off site.

Other Requirements and Information

§ 63.6165 What parts of the General Provisions apply to me?

Table 7 of this subpart shows which parts of the General Provisions in § 63.1 through 15 apply to you.

§ 63.6170 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 EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out 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 section 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the EPA Administrator and are not transferred to the State, local, or tribal agency.

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

(1) Approval of alternatives to the emission limitations or operating limitations in § 63.6100 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 to determine outlet formaldehyde concentration, as specified in § 63.6110(b).

(6) Approval of an alternative to any electronic reporting to the EPA required by this subpart.

[69 FR 10537, Mar. 5, 2004, as amended at 85 FR 13541, Mar. 9, 2020]

§ 63.6175 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA; in 40 CFR 63.2, the General Provisions of this part; and in this section:

Area source means any stationary source of HAP that is not a major source as defined in this part.

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 reciprocating internal combustion engines.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101-549, 104 Stat. 2399).

Cogeneration cycle stationary combustion turbine means any stationary combustion turbine that recovers heat from the stationary combustion turbine exhaust gases using an exhaust heat exchanger, such as a heat recovery steam generator.

Combined cycle stationary combustion turbine means any stationary combustion turbine that recovers heat from the stationary combustion turbine exhaust gases using an exhaust heat exchanger to generate steam for use in a steam turbine.

Combustion turbine engine test cells/stands means engine test cells/stands, as defined in subpart PPPPP of this part, that test stationary combustion turbines.

Compressor station means any permanent combination of compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

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;

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless of whether or not such failure is permitted by this subpart;

(4) Before September 8, 2020, fails to satisfy the general duty to minimize emissions established by § 63.6(e)(1)(i), or

(5) After September 8, 2020, fails to satisfy the general duty to minimize emissions established by § 63.6105.

Diffusion flame gas-fired stationary combustion turbine means:

(1)

(i) Each stationary combustion turbine which is equipped only to fire gas using diffusion flame technology,

(ii) Each stationary combustion turbine which is equipped both to fire gas using diffusion flame technology and to fire oil, during any period when it is firing gas, and

(iii) Each stationary combustion turbine which is equipped both to fire gas using diffusion flame technology and to fire oil, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil no more than an aggregate total of 1000 hours during the calendar year.

(2) Diffusion flame gas-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine,

(ii) Any stationary combustion turbine located on the North Slope of Alaska, or

(iii) Any stationary combustion turbine burning landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or any stationary combustion turbine where gasified MSW is used to generate 10 percent or more of the gross heat input on an annual basis.

Diffusion flame oil-fired stationary combustion turbine means:

(1)

(i) Each stationary combustion turbine which is equipped only to fire oil using diffusion flame technology, and

(ii) Each stationary combustion turbine which is equipped both to fire oil using diffusion flame technology and to fire gas, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil more than an aggregate total of 1000 hours during the calendar year, during any period when it is firing oil.

(2) Diffusion flame oil-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine, or

(ii) Any stationary combustion turbine located on the North Slope of Alaska.

Diffusion flame technology means a configuration of a stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

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.

Distillate oil 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.

Emergency stationary combustion turbine means any stationary combustion turbine that operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency stationary combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary combustion turbines.

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 pollutant (HAP) means any air pollutant listed in or pursuant to section 112(b) of the CAA.

ISO standard day conditions means 288 degrees Kelvin (15 °C), 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 premix gas-fired stationary combustion turbine means:

(1)

(i) Each stationary combustion turbine which is equipped only to fire gas using lean premix technology,

(ii) Each stationary combustion turbine which is equipped both to fire gas using lean premix technology and to fire oil, during any period when it is firing gas, and

(iii) Each stationary combustion turbine which is equipped both to fire gas using lean premix technology and to fire oil, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil no more than an aggregate total of 1000 hours during the calendar year.

(2) Lean premix gas-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine,

(ii) Any stationary combustion turbine located on the North Slope of Alaska, or

(iii) Any stationary combustion turbine burning landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, or any stationary combustion turbine where gasified MSW is used to generate 10 percent or more of the gross heat input on an annual basis.

Lean premix oil-fired stationary combustion turbine means:

(1)

(i) Each stationary combustion turbine which is equipped only to fire oil using lean premix technology, and

(ii) Each stationary combustion turbine which is equipped both to fire oil using lean premix technology and to fire gas, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil more than an aggregate total of 1000 hours during the calendar year, during any period when it is firing oil.

(2) Lean premix oil-fired stationary combustion turbines do not include:

(i) Any emergency stationary combustion turbine, or

(ii) Any stationary combustion turbine located on the North Slope of Alaska.

Lean premix technology means a configuration of a stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber.

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 this section, 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 this section, 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 this standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Municipal solid waste as used in this subpart is as defined in § 60.1465 of Subpart AAAA of 40 CFR Part 60, New Source Performance Standards for Small Municipal Waste Combustion Units.

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. May be field or pipeline quality. For the purposes of this subpart, the definition of natural gas includes similarly constituted fuels such as field gas, refinery gas, and syngas.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Natural gas transmission and storage facility means any grouping of equipment where natural gas is processed, compressed, or stored prior to entering a pipeline to a local distribution company or (if there is no local distribution company) to a final end user. Examples of a facility for this source category are: an underground natural gas storage operation; or a natural gas compressor station that receives natural gas via pipeline, from an underground natural gas storage operation, or from a natural gas processing plant. The emission points associated with these phases include, but are not limited to, process vents. Processes that may have vents include, but are not limited to, dehydration and compressor station engines. Facility, for the purpose of a major source determination, means natural gas transmission and storage equipment that is located inside the boundaries of an individual surface site (as defined in this section) and is connected by ancillary equipment, such as gas flow lines or power lines. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Natural gas transmission and storage equipment or groupings of equipment located on different gas leases, mineral fee tracts, lease tracts, subsurface unit areas, surface fee tracts, or surface lease tracts shall not be considered part of the same facility.

North Slope of Alaska means the area north of the Arctic Circle (latitude 66.5 degrees North).

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 emission control device means an emission control device that incorporates catalytic oxidation to reduce CO emissions.

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.

Regenerative/recuperative cycle stationary combustion turbine means any stationary combustion turbine that recovers heat from the stationary combustion turbine exhaust gases using an exhaust heat exchanger to preheat the combustion air entering the combustion chamber of the stationary combustion turbine.

Research or laboratory facility means any stationary source whose primary purpose is to conduct research and development into new processes and products, where such source is operated under the close supervision of technically trained personnel and is not engaged in the manufacture of products for commercial sale in commerce, except in a *de minimis* matter.

Simple cycle stationary combustion turbine means any stationary combustion turbine that does not recover heat from the stationary combustion turbine exhaust gases.

Startup begins at the first firing of fuel in the stationary combustion turbine. For simple cycle turbines, startup ends when the stationary combustion turbine has reached stable operation or after 1 hour, whichever is less. For combined cycle turbines, startup ends when the stationary combustion turbine has reached stable operation or after 3 hours, whichever is less. Turbines in combined cycle configurations that are operating as simple cycle turbines must meet the startup requirements for simple cycle turbines while operating as simple cycle turbines.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

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.

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.

[69 FR 10537, Mar. 5, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 85 FR 13541, Mar. 9, 2020]

Table 1 to Subpart YYYY of Part 63 - Emission Limitations

As stated in § 63.6100, you must comply with the following emission limitations.

For each new or reconstructed stationary combustion turbine described in § 63.6100 which is . . .	You must meet the following emission limitations . . .
1. a lean premix gas-fired stationary combustion turbine as defined in this subpart, 2. a lean premix oil-fired stationary combustion turbine as defined in this subpart, 3. a diffusion flame gas-fired stationary combustion turbine as defined in this subpart, or 4. a diffusion flame oil-fired stationary combustion turbine as defined in this subpart.	limit the concentration of formaldehyde to 91 ppbvd or less at 15-percent O_2, except during turbine startup. The period of time for turbine startup is subject to the limits specified in the definition of startup in § 63.6175.

[85 FR 13542, Mar. 9, 2020]

Table 2 to Subpart YYYY of Part 63 - Operating Limitations

As stated in §§ 63.6100 and 63.6140, you must comply with the following operating limitations.

For . . .	You must . . .
1. each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is using an oxidation catalyst	maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer. You are not required to use the catalyst inlet temperature data that is recorded during engine startup in the calculations of the 4-hour rolling average catalyst inlet temperature.
2. each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is not using an oxidation catalyst	maintain any operating limitations approved by the Administrator.

[85 FR 13542, Mar. 9, 2020]

Table 3 to Subpart YYYY of Part 63 - Requirements for Performance Tests and Initial Compliance Demonstrations

As stated in § 63.6120, you must comply with the following requirements for performance tests and initial compliance demonstrations.

You must . . .	Using . . .	According to the following requirements . . .
a. demonstrate formaldehyde emissions meet the emission limitations specified in Table 1 by a performance test initially and on an annual basis AND	Test Method 320 of 40 CFR part 63, appendix A; ASTM D6348-12e1[1] provided that the test plan preparation and implementation provisions of Annexes A1 through A8 are followed and the %R as determined in Annex A5 is equal or greater than 70% and less than or equal to 130%;[2] or other methods approved by the Administrator	formaldehyde concentration must be corrected to 15-percent O_2, dry basis. Results of this test consist of the average of the three 1-hour runs. Test must be conducted within 10 percent of 100-percent load.
b. select the sampling port location and the number of traverse points AND	Method 1 or 1A of 40 CFR part 60, appendix A	if using an air pollution control device, the sampling site must be located at the outlet of the air pollution control device.
c. determine the O_2 concentration at the sampling port location AND	Method 3A or 3B of 40 CFR part 60, appendix A; ANSI/ASME PTC 19.10-1981[1] (Part 10) manual portion only; ASTM D6522-11[1] if the turbine is fueled by natural gas	measurements to determine O_2 concentration must be made at the same time as the performance test.
d. determine the moisture content at the sampling port location for the purposes of correcting the formaldehyde concentration to a dry basis	Method 4 of 40 CFR part 60, appendix A or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-12e1[1]	measurements to determine moisture content must be made at the same time as the performance test.

[1] Incorporated by reference, see § 63.14.

[2] The %R value for each compound must be reported in the test report, and all field measurements must be corrected with the calculated %R value for that compound using the following equation:

Reported Results = ((Measured Concentration in Stack)/(%R)) × 100.

[85 FR 13542, Mar. 9, 2020]

Table 4 to Subpart YYYY of Part 63 - Initial Compliance With Emission Limitations

As stated in §§ 63.6110 and 63.6130, you must comply with the following requirements to demonstrate initial compliance with emission limitations

For the . . .	You have demonstrated initial compliance if . . .
emission limitation for formaldehyde.	the average formaldehyde concentration meets the emission limitations specified in Table 1.

Table 5 to Subpart YYYY of Part 63 - Continuous Compliance With Operating Limitations

As stated in §§ 63.6135 and 63.6140, you must comply with the following requirements to demonstrate continuing compliance with operating limitations:

For each stationary combustion turbine complying with the emission limitation for formaldehyde . . .	You must demonstrate continuous compliance by . . .
1. with an oxidation catalyst	continuously monitoring the inlet temperature to the catalyst and maintaining the 4-hour rolling average of the inlet temperature within the range suggested by the catalyst manufacturer.
2. without the use of an oxidation catalyst	continuously monitoring the operating limitations that have been approved in your petition to the Administrator.

Table 6 to Subpart YYYY of Part 63 - Requirements for Reports

As stated in § 63.6150, you must comply with the following requirements for reports

If you own or operate a . . .	you must . . .	According to the following requirements . . .
1. stationary combustion turbine which must comply with the formaldehyde emission limitation	report your compliance status	semiannually, according to the requirements of § 63.6150.
2. stationary combustion turbine which fires landfill gas, digester gas or gasified MSW equivalent to 10 percent or more of the gross heat input on an annual basis	report (1) 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, digester gas, or gasified MSW is equivalent to 10 percent or more of the gross heat input on an annual basis, (2) the operating limits provided in your federally enforceable permit, and any deviations from these limits, and (3) any problems or errors suspected with the meters	annually, according to the requirements in § 63.6150.
3. a lean premix gas-fired stationary combustion turbine or a diffusion flame gas-fired stationary combustion turbine as defined by this subpart, and you use any quantity of distillate oil to fire any new or existing stationary combustion turbine which is located at the same major source	report (1) the number of hours distillate oil was fired by each new or existing stationary combustion turbine during the reporting period, (2) the operating limits provided in your federally enforceable permit, and any deviations from these limits, and (3) any problems or errors suspected with the meters	annually, according to the requirements in § 63.6150.

Table 7 to Subpart YYYY of Part 63 - Applicability of General Provisions to Subpart YYYY

You must comply with the applicable General Provisions requirements:

Citation	Subject	Applies to subpart YYYY	Explanation
§ 63.1	General applicability of the General Provisions	Yes	Additional terms defined in § 63.6175.
§ 63.2	Definitions	Yes	Additional terms defined in § 63.6175.
§ 63.3	Units and abbreviations	Yes	
§ 63.4	Prohibited activities	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	Yes	
§ 63.6(c)(1)-(2)	Compliance dates for existing sources	Yes	
§ 63.6(c)(3)-(4)	[Reserved]		
§ 63.6(c)(5)	Compliance dates for existing area sources that become major	Yes	
§ 63.6(d)	[Reserved]		
§ 63.6(e)(1)(i)	General duty to minimize emissions	Yes before September 8, 2020. No after September 8, 2020. See § 63.6105 for general duty requirement.	
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	Yes before September 8, 2020. No after September 8, 2020.	
§ 63.6(e)(1)(iii)	Operation and Maintenance Requirements	Yes	
§ 63.6(e)(2)	[Reserved]		
§ 63.6(e)(3)	SSMP	Yes before September 8, 2020. No after September 8, 2020.	
§ 63.6(f)(1)	Applicability of standards except during startup, shutdown, or malfunction (SSM)	Yes before September 8, 2020. No after September 8, 2020.	
§ 63.6(f)(2)	Methods for determining compliance	Yes	

Citation	Subject	Applies to subpart YYYY	Explanation
§ 63.6(f)(3)	Finding of compliance	Yes	
§ 63.6(g)(1)-(3)	Use of alternative standard	Yes	
§ 63.6(h)	Opacity and visible emission standards	No	Subpart YYYY does not contain opacity or visible emission standards.
§ 63.6(i)	Compliance extension procedures and criteria	Yes	
§ 63.6(j)	Presidential compliance exemption	Yes	
§ 63.7(a)(1)-(2)	Performance test dates	Yes	Subpart YYYY contains performance test dates at § 63.6110.
§ 63.7(a)(3)	Section 114 authority	Yes	
§ 63.7(b)(1)	Notification of performance test	Yes	
§ 63.7(b)(2)	Notification of rescheduling	Yes	
§ 63.7(c)	Quality assurance/test plan	Yes	
§ 63.7(d)	Testing facilities	Yes	
§ 63.7(e)(1)	Conditions for conducting performance tests	Yes before September 8, 2020. No after September 8, 2020.	
§ 63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart YYYY specifies test methods at § 63.6120.
§ 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 YYYY contains specific requirements for monitoring at § 63.6125.
§ 63.8(a)(2)	Performance specifications	Yes	
§ 63.8(a)(3)	[Reserved]		
§ 63.8(a)(4)	Monitoring for control devices	No	

Citation	Subject	Applies to subpart YYYY	Explanation
§ 63.8(b)(1)	Monitoring	Yes	
§ 63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes	
§ 63.8(c)(1)	Monitoring system operation and maintenance	Yes	
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	Yes before September 8, 2020. No after September 8, 2020.	
§ 63.8(c)(1)(ii)	Parts for repair of CMS readily available	Yes	
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	Yes before September 8, 2020. No after September 8, 2020.	
§ 63.8(c)(2)-(3)	Monitoring system installation	Yes	
§ 63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart YYYY does not require continuous opacity monitoring systems (COMS).
§ 63.8(c)(5)	COMS minimum procedures	No	
§ 63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart YYYY does not require COMS.
§ 63.8(d)(1)-(2)	CMS quality control	Yes	
§ 63.8(d)(3)	Written procedures for CMS	Yes before September 8, 2020. No after September 8, 2020.	
§ 63.8(e)	CMS performance evaluation	Yes	Except for § 63.8(e)(5)(ii), which applies to COMS.
§ 63.8(f)(1)-(5)	Alternative monitoring method	Yes	
§ 63.8(f)(6)	Alternative to relative accuracy test	Yes	
§ 63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6135 and 63.6140.
§ 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.
§ 63.9(c)	Request for compliance extension	Yes	

Citation	Subject	Applies to subpart YYYY	Explanation
§ 63.9(d)	Notification of special compliance requirements for new sources	Yes	
§ 63.9(e)	Notification of performance test	Yes	
§ 63.9(f)	Notification of visible emissions/opacity test	No	Subpart YYYY does not contain opacity or VE standards.
§ 63.9(g)(1)	Notification of performance evaluation	Yes	
§ 63.9(g)(2)	Notification of use of COMS data	No	Subpart YYYY does not contain opacity or VE standards.
§ 63.9(g)(3)	Notification that criterion for alternative to relative accuracy test audit (RATA) is exceeded	Yes	
§ 63.9(h)	Notification of compliance status	Yes	Except that notifications for sources not conducting performance tests are due 30 days after completion of performance evaluations. § 63.9(h)(4) is reserved.
§ 63.9(i)	Adjustment of submittal deadlines	Yes	
§ 63.9(j)	Change in previous information	Yes	
§ 63.9(k)	Electronic reporting procedures	Yes	Only as specified in § 63.9(j).
§ 63.10(a)	Administrative provisions for recordkeeping and reporting	Yes	
§ 63.10(b)(1)	Record retention	Yes	
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns	Yes before September 8, 2020. No after September 8, 2020.	
§ 63.10(b)(2)(ii)	Recordkeeping of failures to meet a standard	Yes before September 8, 2020. No after September 8, 2020. See § 63.6155 for recordkeeping of (1) date, time and duration; (2) listing of affected source or equipment, and an estimate of the quantity of each regulated pollutant emitted over the standard; and (3) actions to minimize emissions and correct the failure.	
§ 63.10(b)(2)(iii)	Maintenance records	Yes	

Citation	Subject	Applies to subpart YYYY	Explanation
§ 63.10(b)(2)(iv)-(v)	Records related to actions during SSM	Yes before September 8, 2020. No after September 8, 2020.	
§ 63.10(b)(2)(vi)-(xi)	CMS records	Yes	
§ 63.10(b)(2)(xii)	Record when under waiver	Yes	
§ 63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	
§ 63.10(b)(2)(xiv)	Records of supporting documentation	Yes	
§ 63.10(b)(3)	Records of applicability determination	Yes	
§ 63.10(c)(1)-(14)	Additional records for sources using CMS	Yes	Except that § 63.10(c)(2)-(4) and (9) are reserved.
§ 63.10(c)(15)	Use of SSM Plan	Yes before September 8, 2020. No after September 8, 2020.	
§ 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 YYYY does not contain opacity or VE standards.
§ 63.10(d)(4)	Progress reports	Yes	
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No. After September 8, 2020, see 63.6150(a) for malfunction reporting requirements.	
§ 63.10(e)(1) and (2)(i)	Additional CMS reports	Yes	
§ 63.10(e)(2)(ii)	COMS-related report	No	Subpart YYYY does not require COMS.
§ 63.10(e)(3)	Excess emissions and parameter exceedances reports	Yes	After September 8, 2020 submitted with the compliance report through CEDRI according to § 63.6150(a).
§ 63.10(e)(4)	Reporting COMS data	No	Subpart YYYY does not require COMS.
§ 63.10(f)	Waiver for recordkeeping and reporting	Yes	
§ 63.11	Flares	No	
§ 63.12	State authority and delegations	Yes	

Citation	Subject	Applies to subpart YYYY	Explanation
§ 63.13	Addresses	Yes	After September 8, 2020 not applicable to reports required to be submitted through CEDRI by 63.6150(c), (e), (f), or (g).
§ 63.14	Incorporation by reference	Yes	
§ 63.15	Availability of information	Yes	

[85 FR 13543, Mar. 9, 2020, as amended at 85 FR 73911, Nov. 19, 2020]

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Part 70 PSD/Significant Source Modification and Significant Permit Modification

Source Description and Location

Source Name:	**Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station**
Source Location:	**2723 East 1500 North, Wheatfield, IN 46392**
County:	**Jasper**
SIC Code:	**4911 (Electric Services)**
Operation Permit No.:	**T 073-45762-00008**
Operation Permit Issuance Date:	**November 13, 2023**
PSD/Significant Source Modification No.:	**073-49556-00008**
Significant Permit Modification No.:	**073-49651-00008**
Permit Reviewer:	**Hachem Ismaili Alaoui**

Source Definition

This stationary source consists of an electric utility generating station with an on-site contractor that processes and moisture conditions fly ash:

(1) The electric utility generating station, Northern Indiana Public Service Company LLC, R.M. Schahfer Station, is the primary operation and is located at 2723 East 1500 North, Wheatfield, Indiana; and

(2) The fly ash processor, EM Materials LLC, is the supporting operation and is located at 2723 East 1500 North, Wheatfield, Indiana.

IDEM has determined that Northern Indiana Public Service Company LLC, R.M. Schahfer Station and EM Materials LLC, will be considered one source as defined by 326 IAC 2-7-1(22) based on contractual control. Therefore, the term “source” in the Part 70 documents refers to both Northern Indiana Public Service Company LLC, R.M. Schahfer Station and EM Materials LLC, as one source.

Separate Part 70 Operating permits will be issued to Northern Indiana Public Service Company LLC, R.M. Schahfer Station and EM Materials LLC, solely for administrative purposes.

This determination was initially made under Part 70 Operating Permit No. 73-23909-00040, issued on July 24, 2007.

Existing Approvals

The source was issued Part 70 Operating Permit Renewal No. 073-45762-00008 on November 13, 2023. The source has since received the following approvals:

Permit Type	Permit Number	Issuance Date
Part 70 SSM	073-47965-00008	January 17, 2025
Part 70 SPM	073-48085-00008	February 4, 2025

County Attainment Status

The source is located in Jasper County.

Pursuant to amendments to Indiana Code IC 13-17-3-14, effective July 1, 2023, a federal regulation that classifies or amends a designation of attainment, nonattainment, or unclassifiable for any area in Indiana under the federal Clean Air Act is effective and enforceable in Indiana on the effective date of the federal regulation.

Pollutant	Designation
SO_2	Unclassifiable or attainment effective April 9, 2018, for the 2010 primary 1-hour SO_2 standard. Better than national secondary standards effective March 3, 1978.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Unclassifiable or attainment effective August 3, 2018, for the 2015 8-hour ozone standard.
$PM_{2.5}$	Unclassifiable or attainment effective April 15, 2015, for the 2012 annual $PM_{2.5}$ standard.
$PM_{2.5}$	Unclassifiable or attainment effective December 13, 2009, for the 2006 24-hour $PM_{2.5}$ standard.
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Unclassifiable or attainment effective January 29, 2012, for the 2010 NO_2 standard.
Pb	Unclassifiable or attainment effective December 31, 2011, for the 2008 lead standard.

(a) Ozone Standards
Volatile organic compounds (VOC) and Nitrogen Oxides (NO_x) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NO_x emissions are considered when evaluating the rule applicability relating to ozone. Jasper County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NO_x emissions were reviewed pursuant to the requirements of Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) $PM_{2.5}$
Jasper 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 of Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(c) Other Criteria Pollutants
Jasper 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 fossil fuel-fired steam electric power plant of more than 250 MMBtu/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), 326 IAC 2-3-2(g), or 326 IAC 2-7-1(20)(B). 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 https://www.supremecourt.gov/opinions/opinions.aspx) 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.

Source Status - Existing Source

The table below summarizes the potential to emit of the entire source, prior to the proposed modification, after consideration of all enforceable limits established in the effective permits. If the control equipment has been determined to be integral, the table reflects the potential to emit (PTE) after consideration of the integral control device.

	Source-Wide Emissions Prior to Modification (ton/year)								
	PM[1]	**PM_{10}[1]**	**$PM_{2.5}$[1, 2]**	**SO_2**	**NO_X**	**VOC**	**CO**	**Single HAP[3]**	**Total HAPs**
Total PTE of Entire Source Including Fugitives*	1129	32162	32162	190203	23004	184	2206	1896	2454
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 (HCl)

*Fugitive HAP emissions are always included in the source-wide emissions.

(a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because a PSD regulated pollutant(s), PM, PM10, PM2.5, SO2, NOx, VOC, and CO, is 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 existing 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.

(c) These emissions are based on the TSD of Part 70 SSM No. 073-47965-00008, issued on January 17, 2025.

Description of Proposed Modification

The Office of Air Quality (OAQ) has reviewed an application, submitted by Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station on September 5, 2025, relating to the following:

(a) *Project #1: 2024 Peaker Project*

The 2024 Peaker Project, permitted under SSM No. 073-47965-00008, issued on January 17, 2025, involved the installation of four (4) simple cycle combustion turbines, one (1) diesel emergency generator, and one (1) diesel fire pump. NIPSCO is requesting to equip the simple cycle turbines, identified as Unit 19A, Unit 19B, Unit 19C, and Unit 20, with CO oxidation catalysts and to include emissions from circuit breakers and piping fugitives.

Due to the above-mentioned changes, the 2024 Peaker Project description is being re-evaluated though this permit modification.

(b) *Project #2: 2026 CCCT Project*

Construct and operate four (4) combined cycle combustion turbines, two (2) auxiliary boilers, two (2) mechanical draft cooling towers, one (1) natural gas-fired dew point heater, six (6) lube oil tanks with demister vents, two (2) diesel-fired emergency generators, two (2) diesel-fired fire pumps, and one (1) diesel storage tank.

As part of the 2026 CCCT project, for the dry bottom pulverized coal-fired boilers, identified as Unit 17 and Unit 18, and their related Cooling Towers, the Permittee is proposing new emission limits in order to establish creditable emissions reductions. Compliance with the new emission limits for Unit 17 and Unit 18 and their related cooling towers is required on and after the date of startup of the first combustion turbine being permitted under the 2026 CCCT Project.

The following is a list of the new emission units and pollution control device(s):

2024 Peaker Project (Only for equipment description purposes)

(a) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, and 19C, approved in 2024 for construction, with a rated maximum heat input capacity of 519 MMBtu per hour, each using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(b) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a rated maximum heat input capacity of 2,416 MMBtu per hour, using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR 60, Subpart KKKK, this is an affected facility]
[Under 40 CFR 60, Subpart TTTTa, this is an affected facility]
[Under 40 CFR 63, Subpart YYYY, this is an affected source]

(c) One (1) diesel emergency generator, identified as EDG1, approved in 2024 for construction, with a rated maximum capacity of 2922 horsepower, and exhausting to stack EDG1.

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

(d) One (1) diesel emergency fire pump, identified as FP1, approved in 2024 for construction, with a rated maximum capacity of 327 horsepower, and exhausting to stack FP1.

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

(e) High Voltage Electric Switchgear Containing Sulfur Hexafluoride (SF6), identified as Peaker - Circuit Breakers.

(f) Natural gas piping components, identified as Peaker - Piping Systems, including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections.

2026 CCCT Project

(e) Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a rated maximum nominal capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a rated maximum heat input of 987 MMBtu per hour, using voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(f) Two (2) natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, approved in 2026 for construction, each with a rated maximum capacity of 115 MMBtu per hour, using low NOx burners, and exhausting to stacks SAUX1 and SAUX2.

[Under 40 CFR 60, Subpart Db, these units are affected facilities]
[Under 40 CFR 63, Subpart DDDDD, these units are affected sources]

(g) One (1) natural gas-fired dew point heater, identified as DPH1, approved in 2026 for construction, with a rated maximum capacity of 28 MMBtu per hour, and exhausting to stack SDPH1.

[Under 40 CFR 60, Subpart Dc, this is an affected facility]
[Under 40 CFR 63, Subpart DDDDD, this is an affected source]

(h) Two (2) mechanical draft cooling towers, identified as CTH1 and CTH2, approved in 2026 for construction, each with a rated maximum circulation of 280,000 gallons of water per minute, TDS of 2,000 ppm, and total drift loss of 0.0005%.

(i) Two (2) 2,500 kW diesel-fired certified emergency generators, identified as EDGCC1 and EDGCC2, approved in 2026 for construction, each with a rated maximum capacity of 3,353 hp, and exhausting to stacks SEDGCC1 and SEDGCC2.

[Under 40 CFR Part 60, Subpart IIII, these units are affected facilities.]
[Under 40 CFR Part 63, Subpart ZZZZ, these units are affected sources.]

(j) Two (2) 244 kW diesel-fired certified emergency fire pumps, identified as FPCC1 and FPCC2, approved in 2026 for construction, each with a rated maximum capacity of 327 hp, and exhausting to stacks SFPCC1 and SFPCC2.

[Under 40 CFR Part 60, Subpart IIII, these units are affected facilities.]
[Under 40 CFR Part 63, Subpart ZZZZ, these units are affected sources.]

(k) One (1) diesel storage tank, identified as TKCC1, approved in 2026 for construction, with a rated maximum storage capacity of 5,000 gallons and rated maximum throughput of 130,000 gallons per year, and exhausting outdoors.

(l) Six (6) lube oil demister vents, identified as LOV21A, LOV21B, LOV22A, LOV22B, LOV21S, and LOV22S, approved in 2026 for construction, each with a vent flow rate of 500 cfm.

(m) High Voltage Electric Switchgear Containing Sulfur Hexafluoride (SF6), identified as CCCT - Circuit Breakers, approved in 2026 for construction.

(n) Natural gas piping components, identified as CCCT - Piping Systems, approved in 2026 for construction, including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections.

Enforcement Issues

There are no pending enforcement actions related to this modification.

Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

Project Aggregation

In 2009 and 2018, the U.S. EPA issued interpretive rules addressing project aggregation interpretation to address multiple changes at major stationary sources for applicability of major modification. Under the EPA November 15, 2018, rulemaking addressing project aggregation criteria in 83 Fed. Reg. 57324, changes at a facility should only be aggregated into a single ‘project’ if they are “substantially related,” which means the projects share a meaningful technical or economic interconnection between the physical and/or operational changes. It further described the case-specific nature of project aggregation determination when evaluating whether changes are substantially related, based on factors, such as technical or economic inter-dependence.

On September 5, 2025, Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station submitted the current application (No. 073-49556-00008) to IDEM to make the modification explained above under section "Description of Proposed Modification". Pursuant to USEPA guidance on project aggregation under the PSD rules, the 2024 Peaker Project and 2026 CCCT Project should be considered for project aggregation. Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station provided the following information and explanation to justify why these two (2) projects are considered separate projects.

In the 2021 Integrated Resource Plan (“2021 IRP”), NIPSCO noted that the company is in a transition period pertaining to its generating assets. It had already retired Units 14 and 15 at R.M. Schahfer Generating Station (RMSGS). As such, the 2021 IRP included planned installation of peaking generation for NIPSCO’s fleet during the transition period. The planned peaking generation was intended to (i) respond to changing market conditions (renewable resources entering the market), (ii) reduce potential market exposure during transition of generating assets, and (iii) replace aging existing combustion turbines (Units 16A and 16B) at RMSGS. During project development, NIPSCO completed an engineering study that determined that the installation of one (1) large industrial frame and three (3) smaller aeroderivative simple cycle combustion turbines (CTs) would best fit NIPSCO’s needs.

As previously noted, NIPSCO applied for a source and permit modification for installation of the peaking generation consisting of natural gas-fired combustion turbines under the 2024 Peaker Project. This application was submitted in June 2024. The 2024 Peaker Project involved installation of four (4) simple cycle combustion turbines to generate electricity to serve peak power demand, an emergency generator, and a fire pump. The 2024 Peaker Project was independently funded; it went through internal capital appropriation approval and regulatory approval process through the Indiana Utility Regulatory Commission (IURC).

The 2026 CCCT Project (under this application) is separately funded and with a separate approval process. The project involves installation of four advanced class CTs that will primarily generate electricity as base load units to serve the future market demand.

The Project will address a resource adequacy deficiency within MISO LRZ 6 for dispatchable resources, as supported by NIPSCO with its 2024 IRP wherein NIPSCO anticipates up to 2,800 MW of additional load, for which the expedited review processes are necessary for resource adequacy to serve growing data centers, advanced manufacturing, and other economic development project load requirements.

Copies of the IRP documents referenced here are included as Appendix C of this application.

(a) Technical Interdependence Evaluation

There is no technical interdependence between the 2024 Peaker Project and the 2026 CCCT Project due to the following factors:

(1) In developing the 2026 CCCT Project, no consideration was given to the equipment and capacities under the 2024 Peaker Project at RMSGS.

(2) Combustion turbines (CTs) under the 2024 Peaker Project do not rely on components or operations that are in any way functionally connected to the CTs under the 2026 CCCT Project.

(3) As planned, CTs under the 2024 Peaker Project would supply electricity to the grid independent of other generation resources. Operation of the proposed equipment under the 2026 CCCT Project is technically independent of the previously permitted installations; there is no overlap between the process units and emissions units under the two projects.

(4) The simple cycle CTs under the 2024 Peaker Project will have their own natural gas supply, separate from the natural gas supply for the CTs under the 2026 CCCT Project.

(5) The 2024 Peaker Project will operate as planned even if the 2026 CCCT Project was not constructed and vice versa.

The above facts demonstrate that there is no technical interconnection or interdependency between the two (2) projects[1]. Neither project is incapable of being performed as planned in the absence of the other project; neither project is impaired by the other; neither project relies on the other to achieve or maintain its design and generation goals; and the projects do not share functionally interconnected components, notably fuel supply, nor do they rely upon functionally interconnected components to provide power to the grid (i.e., CTs).

[1] It is possible that with the design updates, some interconnections may exist to provide redundancy at the plant for safe and efficient operation (available natural gas capacity at the facility etc.) However, the equipment proposed under the two (2) projects would be able to operate independently.

(b) Economic Interdependence Evaluation

There is no economic interdependence between the 2024 Peaker Project and the 2026 CCCT Project due to the following factors:

(1) The 2024 Peaker Project and the 2026 CCCT Project were developed, planned and justified under separate IRPs for NIPSCO with separate engineering studies and under separate capital improvement authorizations, to address separate and independent generation needs. The 2024 Peaker Project will provide the company with the ability to respond to changing market conditions as the company transitions its generation assets towards renewable sources. The potential 2026 CCCT Project will address future baseload generation needs for future growth in demand.

(2) The benefit of the 2024 Peaker Project is not reduced if NIPSCO does not proceed with the 2026 CCCT Project. The economic justification for approval of the 2024 Peaker Project was made well before the 2026 CCCT Project is being developed, and economic viability of the 2024 Peaker Project will not be affected if NIPSCO elects not to proceed with the 2026 CCCT Project.

As noted above, there is no technical or economic interdependency or other relationship between the proposed changes under the 2026 CCCT Project and the previously permitted 2024 Peaker Project. Since the projects are both technically and economically independent of each other, these are unrelated changes. Therefore, the proposed 2026 CCCT Project is not 'substantially related' to the 2024 Peaker Project at RMSGS and is properly considered a separate project for the PSD major modification applicability analysis.

Permit Level Determination – Part 70 Modification to an Existing Source

Pursuant to 326 IAC 2-1.1-1(12), Potential to Emit is defined as "the maximum capacity of a stationary source or emission unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, IDEM, or the appropriate local air pollution control agency."

The following table is used to determine the appropriate permit level under 326 IAC 2-7-10.5. This table reflects the PTE before controls. If the control equipment has been determined to be integral, the table reflects the potential to emit (PTE) after consideration of the integral control device.

	PTE Before Controls of the New Emission Units (ton/year)								
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$[1]**	**SO_2**	**NO_X**	**VOC**	**CO**	**Single HAP[2]**	**Total HAPs**
Turbines (21A, 21B, 22A, and 22B)	220.40	428.31	428.31	121.05	2585.88	363.58	638.66	46.43	78.58
Auxiliary Boilers (AUX1 and AUX2)	1.88	7.51	7.51	0.59	138.27	5.43	82.96	1.78	1.86
Cooling Towers (CTH1 and CTH2)	12.27	7.79	0.03	--	--	--	--	--	--
Dew Point Heater (DPH1)	0.23	0.91	0.91	0.07	12.02	0.66	10.10	0.22	0.23
Lube Oil Demister Vents	0.00	0.35	0.35	--	--	0.35	--	--	--
Emergency Generators (EDGCC1 and EDGCC2)	0.55	0.67	0.65	0.02	17.64	1.08	9.65	0.009	0.018
Emergency Fire Pumps (FPCC1 and FPCC2)	0.05	0.36	0.36	0.34	1.08	0.00	0.94	0.001	0.004
CCCT - Circuit Breakers	--	--	--	--	--	--	--	--	--
CCCT - Piping Systems	--	--	--	--	--	1.52	--	--	--
Diesel Storage Tank (TKCC1)	--	--	--	--	--	0.001	--	--	--
Peaker - Circuit Breakers									
Peaker - Piping Systems	--	--	--	--	--	0.43	--	--	--
Total PTE Before Controls of the New Emission Units:	**235.38**	**445.90**	**438.12**	**122.07**	**2754.89**	**373.04**	**742.31**	**48.42**	**80.69**

	PTE Before Controls of the New Emission Units (ton/year)								
Process / Emission Unit	**PM**	**PM_{10}**	**$PM_{2.5}$[1]**	**SO_2**	**NO_X**	**VOC**	**CO**	**Single HAP[2]**	**Total HAPs**
[1]$PM_{2.5}$ listed is direct $PM_{2.5}$. [2]Single highest HAP (Hexane).									

Appendix A of this TSD reflects the detailed PTE of the modification.

(a) Approval to Construct

Pursuant to 326 IAC 2-7-10.5(g)(1), a Significant Source Modification is required because this modification is subject to 326 IAC 2-2 (Prevention of Significant Deterioration).

Pursuant to 326 IAC 2-7-10.5(g)(4), a Significant Source Modification is required because this modification has the potential to emit PM/PM10/direct PM2.5, sulfur dioxide (SO2), nitrogen oxides (NOx), and VOC at equal to or greater than twenty-five (25) tons per year.

Pursuant to 326 IAC 2-7-10.5(g)(6), a Significant Source Modification is required because this modification has a potential to emit equal to or greater than ten (10) tons per year of a single HAP and twenty-five (25) tons per year of any combination of HAPs.

Pursuant to 326 IAC 2-7-10.5(g)(7), a Significant Source Modification is required because this modification has a potential to emit equal to or greater than one hundred (100) tons per year of carbon monoxide (CO).

(b) Approval to Operate

Pursuant to 326 IAC 2-7-12(d)(1), this change to the permit is being made through a Significant Permit Modification because this modification does not qualify as a Minor Permit Modification or as an Administrative Amendment.

Permit Level Determination – PSD Emissions Increase

2024 Peaker Project
The source is updating the 2024 peaker project

- Project applicability updated with addition of CO oxidation catalyst controls.
- Adding new emissions from Circuit Breakers and the Piping Systems to the 2024 peaker project.

(b) New Emissions Added to the 2024 Peaker Project
Pursuant to 326 IAC 2-2-1(t)(1), a new emissions unit is any emissions unit that is, or will be, newly constructed and that has existed for less than two (2) years from the date the emissions unit first operated.

(A) The following emissions unit(s) are considered as new emissions units for this updated evaluation of the 2024 peaker project.

(1) High Voltage Electric Switchgear Containing Sulfur Hexafluoride (SF6), identified as Peaker - Circuit Breakers.

(2) Natural gas piping components, identified as Peaker - Piping Systems, including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections.

See Appendix A of this Technical Support Document for detailed emission calculations.

Project Emissions Increase (tons/year) 2024 Peaker Project as Updated by PSD/SSM 073-49556-00008									
Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**NO_X**	**VOC**	**CO**	**GHGs**	**H2SO4**
Units 19A, 19B, and 19C	21.59	36.48	36.84	5.78	265.34	24.09	135.30	530,244	10.75
Unit 20	17.04	31.15	31.15	8.88	266.21	48.25	271.98	701,748	14.22
Emergency Generator (EDG1)	0.24	0.29	0.28	0.01	7.69	0.47	4.20	850	0.00
Fire Pump (FP1)	0.03	0.18	0.18	0.17	0.54	0.11	0.47	94	0.01
Peaker - Circuit Breakers	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**85**	**0.00**
Peaker - N.G Piping Systems	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.43**	**0.00**	**570**	**0.00**
Project Emissions Increase	38.90	68.45	68.45	14.83	539.77	~~72.92~~ **73.35**	411.95	~~1,232,973~~ **1,233,629**	24.98
Significant Levels	25	15	10	40	40	40	100	75,000 CO_2e	7
*PM2.5 listed is direct PM2.5. Any values that are highlighted in gray correspond to the limited potential to emit.									

The project emissions for PM, PM10, PM2.5, NOx, VOC, CO, and H2SO4 are each still above the applicable PSD significant thresholds. Therefore, the project is still a significant emissions increase for PM, PM10, PM2.5, NOx, VOC, CO, and H2SO4.

Since the project emissions increase for PM, PM10, PM2.5, NOx, VOC, CO, and GHGs exceeded the significant emissions threshold levels, a netting analysis for these pollutants was required.

(e) Netting Applicability Test

The source performed a netting analysis, specified in 326 IAC 2-2-2(d)(1) and (d)(2), to demonstrate that the modification is not subject to PSD major review for the project PM, PM10, PM2.5, NOx, VOC, CO, and H2SO4 emissions.

For this netting analysis, the source has considered the project emissions increases described above (see ATP Summary), and identified contemporaneous increases and decreases associated with this project:

(h) Net Emissions Increases

Net Emissions Increase (tons/year) 2024 Peaker Project as Updated by PSD/SSM 073-49556-00008									
Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**NO_X**	**VOC**	**CO**	**GHGs**	**H2SO4**
2024 Peaker Project Emissions	38.90	68.45	68.45	14.83	539.77	73.35	411.95	1,233,629	24.98
Contemporaneous Increases	0.11	0.44	0.44	0.03	2.13	0.32	2.17	6,872	0.00
Contemporaneous Decreases	-147.79	-400.91	-361.89	-310.73	-2166.44	-82.31	-4834.98	-5,862,931	-38.46
Project Emissions Increase	**-108.78**	**-332.01**	**-293.01**	**-295.64**	**-1624.53**	~~-9.07~~ **-8.65**	**-4420.86**	~~-4,623,095~~ **-4,622,440**	**-13.49**
Significant Levels	25	15	10	40	40	40	100	75,000 CO_2e	7

Net Emissions Increase (tons/year) 2024 Peaker Project as Updated by PSD/SSM 073-49556-00008									
Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**NO_X**	**VOC**	**CO**	**GHGs**	**H2SO4**
*PM2.5 listed is direct PM2.5. Any values that are highlighted in gray correspond to the limited potential to emit. H2SO4 emissions from Turbine 20 is limited to render the requirements of 326 IAC 2-2 not applicable to this modification.									

See Technical Support Document (TSD) State Rule Applicability - Entire Source section, 326 IAC 2-2 (PSD) and 326 IAC 2-3 (Emission Offset) applicability determination for more information regarding the limits.

(i) Conclusion 2024 Peaker Project
This modification to an existing major PSD stationary source is still not major based on net emissions increases test in 326 IAC 2-2-2 because the Net Emissions Increase of each PSD regulated pollutant is still less than the PSD significant levels (i.e., the modification does not cause a Significant Emissions Increase). Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

2026 CCCT Project

(a) Actual to Potential (ATP) Applicability Test
Since this project only involves the construction of new emissions units and/or emissions units considered new for this evaluation, an Actual to Potential (ATP) applicability test, specified in 326 IAC 2-2-2(d)(4), is used to determine if the project results in a Significant Emissions Increase.

(b) New Emissions Units Only
Pursuant to 326 IAC 2-2-1(t)(1), a new emissions unit is any emissions unit that is, or will be, newly constructed and that has existed for less than two (2) years from the date the emissions unit first operated.

(A) The following proposed emissions unit(s) are considered as new emissions units for this evaluation.

(1) Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a rated maximum capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a rated maximum heat input of 987 MMBtu per hour, using voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

(2) Two (2) natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, approved in 2026 for construction, each with a rated maximum capacity of 115 MMBtu per hour, using low NOx burners, and exhausting to stacks SAUX1 and SAUX2.

(3) One (1) natural gas-fired dew point heater, identified as DPH1, approved in 2026 for construction, with a rated maximum capacity of 28 MMBtu per hour, and exhausting to stack SDPH1.

(4) Two (2) mechanical draft cooling towers, identified as CTH1 and CTH2, approved in 2026 for construction, each with a rated maximum circulation of 280,000 gallons of water per minute, TDS of 2,000 ppm, and total drift loss of 0.0005%.

(5) Two (2) 2,500 kW diesel-fired certified emergency generators, identified as EDGCC1 and EDGCC2, approved in 2026 for construction, each with a rated maximum capacity of 3,353 hp, and exhausting to stacks SEDGCC1 and SEDGCC2.

(6) Two (2) 244 kW diesel-fired certified emergency fire pumps, identified as FPCC1 and FPCC2, approved in 2026 for construction, each with a rated maximum capacity of 327 hp, and exhausting to stacks SFPCC1 and SFPCC2.

(7) One (1) diesel storage tank, identified as TKCC1, approved in 2026 for construction, with a design storage capacity of 5,000 gallons and a rated throughput of 130,000 gallons per year, and exhausting outdoors.

(8) Six (6) lube oil demister vents, identified as LOV21A, LOV21B, LOV22A, LOV22B, LOV21S, and LOV22S, approved in 2026 for construction, each with a vent flow rate of 500 cfm.

(9) High Voltage Electric Switchgear Containing Sulfur Hexafluoride (SF6), identified as CCCT - Circuit Breakers, approved in 2026 for construction.

(10) Natural gas piping components, identified as CCCT - Piping Systems, approved in 2026 for construction, including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections

(c) Baseline Actual Emissions

For a new emissions unit, the baseline actual emissions for purposes of determining the Emissions Increase that will result from the initial construction and operation of the unit shall equal zero (0) and thereafter, for all other purposes, shall equal the unit's potential to emit.

(d) Actual to Potential (ATP) Summary

The Emissions Increase of the project is the sum of the difference between the potential to emit (PTE) from each new emissions unit following completion of the project and the baseline actual emissions of these units before the project.

$ATP_{(new\ unit)} = PTE_{(new\ unit)} - Baseline\ Emissions_{(new\ unit)}$

See Appendix A of this Technical Support Document for detailed emission calculations.

Project Emissions Increase (tons/year) 2026 CCCT Project									
Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**NO_X**	**VOC**	**CO**	**GHGs**	**H2SO4**
Units 21A, 21B, 22A, and 22B (combined cycle – worst case)	120.25	228.02	228.02	79.99	1,566.28	249.94	510.49	6,934,113	57.48
Auxiliary Boilers AUX1 and AUX2	1.88	7.51	7.51	0.59	138.27	5.43	82.96	118,749	0.00

Project Emissions Increase (tons/year) 2026 CCCT Project									
Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**NO_X**	**VOC**	**CO**	**GHGs**	**H2SO4**
Cooling Towers CTH1 and CTH2	12.27	7.79	0.03	--	--	--	--	--	--
Dew Point Heater DPH1	0.23	0.91	0.91	0.07	12.02	0.66	10.10	14,506	0.00
Lube Oil Tanks Demister Vents	0.00	0.35	0.35	--	--	0.35	--	--	--
Emergency Generators EDGCC1 and EDGCC2	0.55	0.67	0.65	0.02	17.64	1.08	9.65	1,952	0.00
Emergency Fire Pumps FPCC1 and FPCC2	0.05	0.36	0.36	0.34	1.08	0.00	0.94	189	0.01
CCCT - Circuit Breakers	--	--	--	--	--	--	--	1,022	--
CCCT - N.G Piping Fugitives	--	--	--	--	--	1.52	--	2024	--
Diesel Storage Tank TKCCT	--	--	--	--	--	0.00	--	--	--
Project Emissions Increase	**135.24**	**245.62**	**237.83**	**80.01**	**1,735.29**	**258.97**	**614.14**	**7,072,554**	**57.49**
Significant Levels	25	15	10	40	40	40	100	75,000 CO_2e	7

*PM2.5 listed is direct PM2.5.
Any values that are highlighted in gray correspond to the limited potential to emit.

The project emissions for PM, PM10, PM2.5, NOx, VOC, CO, and H2SO4 are each above the applicable PSD significant thresholds. Therefore, the project is a significant emissions increase for PM, PM10, PM2.5, NOx, VOC, CO, and H2SO4.

The source performed a netting analysis, specified in 326 IAC 2-2-2(d)(1) and (d)(2), to demonstrate that the modification is not subject to PSD major review for the project PM, PM10, PM2.5, NOx, CO, and H2SO4 emissions. The Project results in significant net emissions increases for VOC and GHGs. See discussion under State rule applicability.

(e) Netting Applicability Test

The source performed a netting analysis, specified in 326 IAC 2-2-2(d)(1) and (d)(2), to demonstrate that the modification is not subject to PSD major review for the project PM, PM10, PM2.5, NOx, CO, and H2SO4 emissions. The Project results in significant net emissions increases for VOC and GHGs.

For this netting analysis, the source has considered the project emissions increases described above (see ATP Summary), and identified contemporaneous increases and decreases associated with this project:

(f) Contemporaneous Emissions Decreases

Contemporaneous Decreases (tons/year) 2026 CCCT Project									
Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**NO_X**	**VOC**	**CO**	**GHGs**	**H2SO4**
Unit 15 Shutdown in September 28, 2021(baseline period 2018-2019)									

Contemporaneous Decreases (tons/year) 2026 CCCT Project									
Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**NO_X**	**VOC**	**CO**	**GHGs**	**H2SO4**
PTE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Baseline Actual Emissions (average emissions for 2018 and 2019)	68.26	259.64	246.04	171.54	1448.14	36.21	4622.34	2,380,454	4.63
BAE (Unit 15)	-68.26	-259.64	-246.04	-171.54	-1,448.14	-36.21	-4,622.34	-2,380,454	-4.63
*Unit 17 (Baseline Actual Emissions for Period from March 2021 to Feb 2023)**									
Baseline Actual Emissions	25.80	152.22	147.05	387.82	1,179.43	18.76	151.97	1,535,867	172.77
*Unit 18 (Baseline Actual Emissions for Period from March 2021 to Feb 2023)**									
Baseline Actual Emissions	42.03	159.82	151.41	277.17	1,206.72	17.73	147.78	1,464,617	178.65
*Unit 17 Cooling Tower (Baseline Actual Emissions for Period from March 2021 to Feb 2023)**									
Baseline Actual Emissions	50.16	35.11	21.07	0.00	0.00	0.00	0.00	0.00	0.00
*Unit 18 Cooling Tower (Baseline Actual Emissions for Period from March 2021 to Feb 2023)**									
Baseline Actual Emissions	54.44	38.11	22.86	0.00	0.00	0.00	0.00	0.00	0.00
Total Baseline Actual Emissions for Unit 17, Unit 18, Unit 17 Cooling Tower, Unit 18 Cooling Tower	172.43	385.25	342.40	664.99	2,386.15	36.49	299.75	3,000,484	351.41
Allowable Emissions for Unit 17, Unit 18, Unit 17 Cooling Tower, Unit 18 Cooling Tower	91.00	345.00	292.00	664.99	1,560.00	NA	299.75	NA	280.00
Emissions Decreases for Unit 17, Unit 18, Unit 17 Cooling Tower, Unit 18 Cooling Tower	-81.43	-40.25	-50.40	0.00	-826.15	0.00	0.00	0.00	-71.41
Total Emissions Decreases	**-149.69**	**-299.89**	**-296.43**	**-171.54**	**-2,274.29**	**NA**	**-4,622.34**	**NA**	**-76.04**

* *Due to the executive order issued by department of energy (DOE) on December 23, 2025, Unit 17 and Unit 18 and their associated cooling towers will continue to operate under new emission limitations from the date of startup of the first combustion turbine under the 2026 CCCT Project. Therefore, in accordance with 326 IAC 2-2-1(e)(1), baseline period from March 2021 to Feb 2023 was determined to be representative of normal source operation for Unit 17 and Unit 18 and their associated cooling towers*

(g) Contemporaneous Emissions Increases

The following emissions increases are contemporaneous with the proposed modification.

2024 Peaker Project

Contemporaneous Increases (tons/year)									
Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**NO_X**	**VOC**	**CO**	**GHGs**	**H2SO4**
2024 Peaker Project									
Project Emissions Increases	38.90	68.45	68.45	14.83	539.77	73.35	411.95	1,233,629	24.98
Project Emissions Increases	**38.90**	**68.45**	**68.45**	**14.83**	**539.77**	**73.35**	**411.95**	**1,233,629**	**24.98**

(h) Net Emissions Increases

Net Emissions Increase (tons/year)									
Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**NO_X**	**VOC**	**CO**	**GHGs**	**H2SO4**
ATP for New Emissions Units	135.24	245.62	237.83	81.01	1,735.29	258.97	614.14	7,072,554	57.49
Contemporaneous Increases	38.90	68.45	68.45	14.83	539.77	NA	411.95	NA	24.98
Contemporaneous Decreases	-149.69	-299.89	-296.43	-171.54	-2,274.29	NA	-4,622.34	NA	-76.04
Project Emissions Increase	**24.45**	**14.18**	**9.84**	**-75.69**	**0.77**	**NA**	**-3,596.26**	**NA**	**6.42**
Significant Levels	25	15	10	40	40	40	100	75,000 CO_2e	7

*PM2.5 listed is direct PM2.5.

Any values that are highlighted in gray correspond to the limited potential to emit. PM, PM10, PM2.5, NOx and SAM emissions are limited to render the requirements of 326 IAC 2-2 not applicable to this modification.

The source opted to take PM, PM10, PM2.5, NOx, and H2SO4 emission limits in order to render the requirements of 326 IAC 2-2 not applicable to the 2026 CCCT Project.

See Technical Support Document (TSD) State Rule Applicability - Entire Source section, 326 IAC 2-2 (PSD) applicability determination for more information regarding the limits.

(i) Conclusion

The Permittee has provided information as part of the application for this approval. Based on net emissions increases test in 326 IAC 2-2-2, this modification to an existing major PSD stationary source is major because the Project Emissions Increases of VOC and GHGs is greater than the significance level of 40 tons per year for VOC and 75,000 tons per year for CO2e, respectively.

PTE of the Entire Source After Issuance of the Part 70 Modification

The table below summarizes the after issuance source-wide potential to emit, reflecting all limits, of the emission units. Any control equipment is considered federally enforceable only after issuance of the Part 70 source and permit modification, and only to the extent that the effect of the control equipment is made practically enforceable in the permit. If the control equipment has been determined to be integral, the table reflects the potential to emit (PTE) after consideration of the integral control device.

	Source-Wide Emissions After Issuance (ton/year)									
	PM[1]	**PM_{10}[1]**	**$PM_{2.5}$[1, 2]**	**SO_2**	**NO_X**	**VOC**	**CO**	**H2SO4**	**Single HAP[3]**	**Total HAPs**
Total Limited PTE of Entire Source Including Fugitives*	**>100**	**>100**	**>100**	**>100**	**>100**	**>100**	**>100**	**>100**	**>10**	**>25**
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100	10	25
PSD Major Source Thresholds	100	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 (HCl)
*Fugitive HAP emissions are always included in the source-wide emissions.

(a) This existing major PSD stationary source will continue to be major under 326 IAC 2-2 because at least one pollutant, PM, PM10, PM2.5, SO2, NOx, VOC, and CO, has emissions equal to or greater than the PSD major source threshold.

(b) This existing major source of HAP will continue to be a major source of HAP, as defined in 40 CFR 63.2, because HAP emissions will continue to be equal to or greater than ten (10) tons per year for any single HAP and/or equal to or greater than twenty-five (25) tons per year of a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA).

Federal Rule Applicability Determination

Due to the modification at this source, federal rule applicability has been reviewed as follows:

New Source Performance Standards (NSPS):

2026 CCCT Project

(a) The requirements of the New Source Performance Standard for Fossil Fuel Fired Steam Generators, 40 CFR 60, Subpart D and 326 IAC 12, are not included in the permit for the two (2) auxiliary boilers, identified as AUX1 and AUX2, because each auxiliary boiler has a maximum rated heat input less than 250 MMBtu per hour.

(b) The requirements of the New Source Performance Standard for Electric Utility Steam Generating Units, 40 CFR 60, Subpart Da and 326 IAC 12, are not included in the permit for the combined cycle combustion turbine heat recovery steam generator (HRSG) duct burners, identified as Units 21A, 21B, 22A, and 22B, because these units are subject to the requirements of 40 CFR 60, Subpart KKKK. Pursuant to 40 CFR 60.40Da(e), any facility subject to Subpart KKKK is not subject to Subpart Da.

(c) The requirements of the New Source Performance Standard for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Db and 326 IAC 12, are not included in the permit for the heat recovery steam generator (HRSG) duct burners for the combined cycle turbines (Units 21A, 21B, 22A, and 22B), since, pursuant to 40 CFR 60.40b(i), the heat recovery steam generator (HRSG) duct burners are exempt from the requirements of subpart Db because these are subject to Subpart KKKK.

(d) The requirements of the New Source Performance Standard for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Db and 326 IAC 12, are not included in

the permit for the natural gas-fired dew point heater DPH1, because this unit has a maximum rated heat input capacity less than 100 MMBtu per hour.

(e) The auxiliary boilers, identified as AUX1 and AUX2 are subject to the New Source Performance Standards for Industrial Commercial Institutional Steam Generating Units, 40 CFR 60, Subpart Db and 326 IAC 12, because each auxiliary boiler has a maximum rated heat input capacity greater than 100 MMBtu per hour.

The two (2) auxiliary boilers, identified as AUX1 and AUX2, are subject to the following portions of Subpart Db.

60.40b(a)	Applicability and delegation of authority.
60.41b	Definitions.
60.42b(k)(2)	Standard for sulfur dioxide (SO2).
60.44b(l)(1)	Standard for nitrogen oxides (NOx).
60.46b(e)(1)-(4)	Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.
60.48b(b), (c), (e), (f) and (g)	Emission monitoring for particulate matter and nitrogen oxides.
60.49b(a)-(c), (d), (g), (h), (i), (o), (r)(1), (v) and (w)	Reporting and recordkeeping requirements.

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the two (2) auxiliary boilers, identified as AUX1 and AUX2, except as otherwise specified in 40 CFR 60, Subpart Db.

(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 heat recovery steam generator (HRSG) duct burners for the combined cycle turbines (Units 21A, 21B, 22A, and 22B), because each duct burner have a maximum design heat input capacity greater than 100 MMBtu per hour.

(g) 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 two (2) auxiliary boilers, identified as AUX1 and AUX2, because each auxiliary boiler has a maximum rated design heat input capacity greater than 100 MMBtu per hour.

(h) The natural gas-fired dew point heater DPH1 is subject to the New Source Performance Standards for Small Industrial Commercial Institutional Steam Generating Units, 40 CFR 60, Subpart Dc and 326 IAC 12, because this natural gas-fired dew point heater DPH1 will be constructed after June 9, 1989 and has a maximum rated design heat input greater than ten (10) MMBtu per hour and less than one hundred (100) MMBtu per hour.

The natural gas-fired dew point heater DPH1 is subject to the following portions of Subpart Dc.

60.40c	Applicability and delegation of authority.
60.41c	Definitions.
60.48c(a), (g)(1) and (g)(2)	Reporting and recordkeeping requirements.

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the natural gas-fired dew point heater DPH1 except as otherwise specified in 40 CFR 60, Subpart Dc.

(i) The requirements of the New Source Performance Standard for Stationary Gas Turbines, 40 CFR 60, Subpart GG and 326 IAC 12, are not included in the permit for the natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B, because they are subject to 40 CFR 60, Subpart KKKK.

(j) The two (2) diesel-fired emergency generators, identified as EDGCC1 and EDGCC2, are subject to the New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII and 326 IAC 12, because these units are stationary compression ignition (CI) internal combustion engines (ICE) and will commence construction after July 11, 2005.

The two (2) diesel-fired emergency generators, identified as EDGCC1 and EDGCC2, are subject to the following portions of Subpart IIII.

60.4200(a)(2)(i)	Am I subject to this subpart?
60.4204(b)	What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
60.4205(b)	What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
60.4206	How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?
60.4207(b)	What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?
60.4208	What is the deadline for importing or installing stationary CI ICE produced in previous model years?
60.4209	What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?
60.4211(a), (c), (f) and (g)(3)	What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?
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?
60.4214(b), (d), (g), (h), (i) and (j)	What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?
60.4218	What General Provisions and confidential information provisions apply to me?
60.4219	What definitions apply to this subpart?
Tables to Subpart IIII of Part 60	
Table 8	Applicability of General Provisions to Subpart IIII

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the two (2) diesel-fired emergency fire pumps, identified as FPCC1 and FPCC2, except as otherwise specified in 40 CFR 60, Subpart IIII.

(k) The two (2) diesel-fired emergency fire pumps, identified as FPCC1 and FPCC2, are subject to the New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII and 326 IAC 12, because these units are stationary compression ignition (CI) internal combustion engines (ICE) and will commence construction after July 11, 2005.

The two (2) diesel-fired emergency fire pumps, identified as FPCC1 and FPCC2, are subject to the following portions of Subpart IIII.

60.4200(a)(2)(ii)	Am I subject to this subpart?
60.4204(b)	What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
60.4205(c)	What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
60.4206	How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

60.4207(b)	What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?
60.4208	What is the deadline for importing or installing stationary CI ICE produced in previous model years?
60.4209	What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?
60.4211(a), (c), (f) and (g)(2)	What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?
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?
60.4214(b), (d), (g), (h), (i) and (j)	What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?
60.4218	What General Provisions and confidential information provisions apply to me?
60.4219	What definitions apply to this subpart?
Tables to Subpart IIII of Part 60	
Table 8	Applicability of General Provisions to Subpart IIII

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the two (2) diesel-fired emergency fire pumps, identified as FPCC1 and FPCC2, except as otherwise specified in 40 CFR 60, Subpart IIII.

(l) 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 the two (2) diesel-fired emergency generators, identified as EDGCC1 and EDGCC2, because they are not stationary spark ignition internal combustion engines.

(m) The natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B, are subject to the New Source Performance Standards for Stationary Combustion Turbines, 40 CFR 60, Subpart KKKK and 326 IAC 12, because each of these gas turbines has a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour and construction of these stationary combustion turbines commenced after February 18, 2005 but prior to December 13, 2024. NIPSCO entered a binding contract with GE Vernova on November 22, 2024. This agreement includes associated penalties for cancellation and constitutes commencement of construction as defined in 40 CFR 60.2 for purposes of the NSPS program. Therefore, the construction of the 2026 CCCT Project combustion turbines commenced prior to December 13, 2024, the publication date of the proposed NSPS 40 CFR 60 Subpart KKKKa.

The natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B, are subject to the following portions of Subpart KKKK.

60.4305	Does this subpart apply to my stationary combustion turbine?
60.4315	What pollutants are regulated by this subpart?
60.4320(a)	What emission limits must I meet for nitrogen oxides (NOX)?
60.4330(a)	What emission limits must I meet for sulfur dioxide (SO2?
60.4333	What are my general requirements for complying with this subpart?
60.4340	How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?
60.4345	What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?
60.4350	How do I use data from the continuous emission monitoring equipment to identify excess emissions?
60.4355	How do I establish and document a proper parameter monitoring plan?

60.4365	How can I be exempted from monitoring the total sulfur content of the fuel?
60.4370(b)	How often must I determine the sulfur content of the fuel?
60.4375	What reports must I submit?
60.4380	How are excess emissions and monitor downtime defined for NOX?
60.4395	When must I submit my reports?
60.4400	How do I conduct the initial and subsequent performance tests, regarding NOX?
60.4405	How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS?
60.4410	How do I establish a valid parameter range if I have chosen to continuously monitor parameters?
60.4420	What definitions apply to this subpart?
Tables to Subpart KKKK of Part 60	
Table 1	Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B, except as otherwise specified in 40 CFR 60, Subpart KKKK.

(n) The requirements of the New Source Performance Standard for Stationary Combustion Turbines, 40 CFR 60, Subpart KKKKa and 326 IAC 12, are not included in the permit for the natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B, because the construction of each of the natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B, commenced prior to December 13, 2024 as defined under 40 CFR 60.2.

(o) The requirements of the New Source Performance Standard for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR 60, Subpart TTTT and 326 IAC 12, are not included in the permit for the natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B, because the construction of these turbines commenced after May 23, 2023.

(p) The natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B, are subject to the New Source Performance Standards for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units, 40 CFR 60, Subpart TTTTa and 326 IAC 12, because these units are stationary combustion turbines that commenced construction after May 23, 2023, each has base load rating greater than 250 MMBtu per hour of fossil fuel, and each serve generators capable of selling greater than 25 MW of electricity to a utility power distribution system.

The natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B, are subject to the following portions of Subpart TTTTa.

60.5509a(a)	Am I subject to this subpart?
60.5515a	Which pollutants are regulated by this subpart?
60.5520a	What CO_2 emissions standard must I meet?
60.5525a	What are my general requirements for complying with this subpart?
60.5535a	How do I monitor and collect data to demonstrate compliance?
60.5550a	What notifications must I submit and when?
60.5555a	What reports must I submit and when?
60.5560a	What records must I maintain?
60.5565a	In what form and how long must I keep my records?
60.5570a	What parts of the general provisions apply to my affected EGU?
60.5575a	Who implements and enforces this subpart?

60.5580a	What definitions apply to this subpart?
Tables to Subpart TTTTa of Part 60	
Table 1	CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After May 23, 2023 (Gross or Net Energy Output-Based Standards Applicable as Approved by the Administrator)
Table 3	Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTTa

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B, except as otherwise specified in 40 CFR 60, Subpart TTTTa.

(q) The requirements of the New Source Performance Standard for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After October 4, 2023, 40 CFR 60, Subpart Kc and 326 IAC 12, are not included in the permit for the diesel storage tank, identified as TKCC1, because this storage tank has storage capacity less than 20,000 gallons (75.7 m^3).

(r) There are no other New Source Performance Standards (40 CFR Part 60) and 326 IAC 12 included in the permit for this proposed modification.

National Emission Standards for Hazardous Air Pollutants (NESHAP):

2024 Peaker Project

(a) The diesel-fired emergency generator, identified as EDG1, is subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ, which is incorporated by reference as326 IAC 20-82, because this engine is considered a new (construction commenced on or after June 12, 2006) stationary reciprocating internal combustion engine (RICE) at a major source of hazardous air pollutants (HAPs).

The diesel-fired emergency generator, identified as EDG1, is subject to the following portions of Subpart ZZZZ:

63.6580	What is the purpose of subpart ZZZZ?
63.6585(b)	Am I subject to this subpart?
63.6590(a)(2)(i) and (b)(1)(i)	What parts of my plant does this subpart cover?

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the diesel-fired emergency generator, identified as EDG1, except as otherwise specified in 40 CFR 63, Subpart ZZZZ.

(b) The diesel-fired emergency fire pump, identified as FP1, is subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ, which is incorporated by reference as326 IAC 20-82, because this engine is considered new (construction commenced on or after June 12, 2006) stationary reciprocating internal combustion engines (RICE) at a major source of hazardous air pollutants (HAPs).

The diesel-fired emergency fire pump, identified as FP1, is subject to the following portions of Subpart ZZZZ:

63.6580	What is the purpose of subpart ZZZZ?
63.6585(b)	Am I subject to this subpart?
63.6590(a)(2)(ii) and (c)(7)	What parts of my plant does this subpart cover?

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the diesel-fired emergency fire pump, identified as FP1, except as otherwise specified in 40 CFR 63, Subpart ZZZZ.

(c) The natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, are subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, 40 CFR 63, Subpart YYYY, which is incorporated by reference as 326 IAC 20-90, because these units are stationary combustion turbines located at a major source of HAP emissions.

The natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, are subject to the following portions of Subpart YYYY:

63.6080	What is the purpose of subpart YYYY?
63.6085	Am I subject to this subpart?
63.6090	What parts of my plant does this subpart cover?
63.6092	Are duct burners and waste heat recovery units covered by subpart YYYY?
63.6095	When do I have to comply with this subpart?
63.6100	What emission and operating limitations must I meet?
63.6105(c)	What are my general requirements for complying with this subpart?
63.6110	By what date must I conduct the initial performance tests or other initial compliance demonstrations?
63.6115	When must I conduct subsequent performance tests?
63.6120	What performance tests and other procedures must I use?
63.6125(a)	What are my monitor installation, operation, and maintenance requirements?
63.6130	How do I demonstrate initial compliance with the emission and operating limitations?
63.6135	How do I monitor and collect data to demonstrate continuous compliance?
63.6140	How do I demonstrate continuous compliance with the emission and operating limitations?
63.6145	What notifications must I submit and when?
63.6150	What reports must I submit and when?
63.6155	What records must I keep?
63.6160	In what form and how long must I keep my records?
63.6165	What parts of the General Provisions apply to me?
63.6170	Who implements and enforces this subpart?
63.6175	What definitions apply to this subpart?
Tables to Subpart YYYY of Part 63	
Table 1	Emission Limitations
Table 2	Operating Limitations
Table 3	Requirements for Performance Tests and Initial Compliance Demonstrations
Table 4	Initial Compliance With Emission Limitations
Table 5	Continuous Compliance With Operating Limitations
Table 6	Requirements for Reports
Table 7	Applicability of General Provisions to Subpart YYYY

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the natural gas-fired simple cycle combustion turbines, identified as Units 19A, 19B, 19C, and Unit 20, except as otherwise specified in 40 CFR 63, Subpart YYYY.

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(d) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial Process Cooling Towers, 40 CFR 63, Subpart Q and 326 IAC 20-4 are not included in the permit for the two (2) mechanical draft cooling towers, identified as CTH1 and CTH2, since these cooling towers do not use and chromium-based water treatment chemicals.

(e) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Stationary Combustion Turbines, 40 CFR 63, Subpart YYYY and 326 IAC 20-90 are not included in the permit for the heat recovery steam generator (HRSG) duct burner for the combined cycle turbines (Units 21A, 21B, 22A, and 22B), since, pursuant to 40 CFR 63.6092, the HRSG duct burner is exempt because it is considered a steam generating unit.

(f) The natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B, are subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, 40 CFR 63, Subpart YYYY, which is incorporated by reference as 326 IAC 20-90, because these units are stationary combustion turbines located at a major source of HAP emissions.

The natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B, are subject to the following portions of Subpart YYYY:

63.6080	What is the purpose of subpart YYYY?
63.6085	Am I subject to this subpart?
63.6090	What parts of my plant does this subpart cover?
63.6092	Are duct burners and waste heat recovery units covered by subpart YYYY?
63.6095	When do I have to comply with this subpart?
63.6100	What emission and operating limitations must I meet?
63.6105(c)	What are my general requirements for complying with this subpart?
63.6110	By what date must I conduct the initial performance tests or other initial compliance demonstrations?
63.6115	When must I conduct subsequent performance tests?
63.6120	What performance tests and other procedures must I use?
63.6125(a)	What are my monitor installation, operation, and maintenance requirements?
63.6130	How do I demonstrate initial compliance with the emission and operating limitations?
63.6135	How do I monitor and collect data to demonstrate continuous compliance?
63.6140	How do I demonstrate continuous compliance with the emission and operating limitations?
63.6145	What notifications must I submit and when?
63.6150	What reports must I submit and when?
63.6155	What records must I keep?
63.6160	In what form and how long must I keep my records?
63.6165	What parts of the General Provisions apply to me?
63.6170	Who implements and enforces this subpart?
63.6175	What definitions apply to this subpart?
Tables to Subpart YYYY of Part 63	
Table 1	Emission Limitations
Table 2	Operating Limitations
Table 3	Requirements for Performance Tests and Initial Compliance Demonstrations
Table 4	Initial Compliance With Emission Limitations
Table 5	Continuous Compliance With Operating Limitations
Table 6	Requirements for Reports

Table 7	Applicability of General Provisions to Subpart YYYY

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B, except as otherwise specified in 40 CFR 63, Subpart YYYY.

(g) The two (2) diesel-fired emergency generators, identified as EDGCC1 and EDGCC2, are subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ, which is incorporated by reference as 326 IAC 20-82, because these engines are considered new (construction commenced on or after June 12, 2006) stationary reciprocating internal combustion engine (RICE) at a major source of hazardous air pollutants (HAPs).

The two (2) diesel-fired emergency generators, identified as EDGCC1 and EDGCC2, are subject to the following portions of Subpart ZZZZ:

63.6580	What is the purpose of subpart ZZZZ?
63.6585(b)	Am I subject to this subpart?
63.6590(a)(2)(i) and (b)(1)(i)	What parts of my plant does this subpart cover?

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the two (2) diesel-fired emergency generators, identified as EDGCC1 and EDGCC2, except as otherwise specified in 40 CFR 63, Subpart ZZZZ.

(h) The two (2) diesel-fired emergency fire pumps, identified as FPCC1 and FPCC2, are subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ, which is incorporated by reference as326 IAC 20-82, because these engines are considered new (construction commenced on or after June 12, 2006) stationary reciprocating internal combustion engines (RICE) at a major source of hazardous air pollutants (HAPs).

The two (2) diesel-fired emergency fire pumps, identified as FPCC1 and FPCC2, are subject to the following portions of Subpart ZZZZ:

63.6580	What is the purpose of subpart ZZZZ?
63.6585(b)	Am I subject to this subpart?
63.6590(a)(2)(ii) and (c)(7)	What parts of my plant does this subpart cover?

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the two (2) diesel-fired emergency fire pumps, identified as FPCC1 and FPCC2, except as otherwise specified in 40 CFR 63, Subpart ZZZZ.

(i) The natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, and the natural gas-fired dew point heater, identified as DPH1, 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 as326 IAC 20-95, because these units are industrial, commercial, or institutional boiler or process heater as defined in 40 CFR 63.7575 and are located at a major source of HAP.

The natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, and the natural gas-fired dew point heater, identified as DPH1, are subject to the following portions of Subpart DDDDD:

63.7480	What is the purpose of this subpart?
63.7485	Am I subject to this subpart?
63.7490(a)(2) and (b)	What is the affected source of this subpart?
63.7495(a)	When do I have to comply with this subpart?

63.7499(l)	What are the subcategories of boilers and process heaters?
63.7500	What emission limitations, work practice standards, and operating limits must I meet?
63.7505(a)	What are my general requirements for complying with this subpart?
63.7510	What are my initial compliance requirements and by what date must I conduct them?
63.7515	When must I conduct subsequent performance tests, fuel analyses, or tune-ups?
63.7545	What notifications must I submit and when?
63.7550	What reports must I submit and when?
63.7555	What records must I keep?
63.7560	In what form and how long must I keep my records?
63.7565	What parts of the General Provisions apply to me?
63.7570	Who implements and enforces this subpart?
63.7575	What definitions apply to this subpart?
Tables to Subpart DDDDD of Part 63	
Table 1	Emission Limits for New or Reconstructed Boilers and Process Heaters [c]
Table 3	Work Practice Standards
Table 9	Reporting Requirements
Table 10	Applicability of General Provisions to Subpart DDDDD
Table 14	Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters [c]

The requirements of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated as 326 IAC 20-1, apply to the natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, and the natural gas-fired dew point heater, identified as DPH1, except as otherwise specified in 40 CFR 63, Subpart DDDDD.

(j) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR 63, Subpart JJJJJJ are not included in the permit for the natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, and the natural gas-fired dew point heater, identified as DPH1, since this source is a major source of HAPs and these units are gas-fired units.

(k) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Industrial, Commercial, and Institutional Boilers Area Sources, 40 CFR 63, Subpart JJJJJJ are not included in the permit for the heat recovery steam generator (HRSG) duct burner for the combined cycle turbines (Units 21A, 21B, 22A, and 22B), since it does not meet the definition of a boiler and this source is a major source of HAPs.

(l) There are no other National Emission Standards for Hazardous Air Pollutants under 40 CFR 63, 326 IAC 14 and 326 IAC 20 included for this proposed modification.

Compliance Assurance Monitoring (CAM):

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to each 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.

(c) Pursuant to 40 CFR 64.2(b)(1)(iii), Acid Rain requirements pursuant to Sections 404, 405, 406, 407(a), 407(b), or 410 of the Clean Air Act are exempt emission limitations or standards. Therefore, CAM was not evaluated for emission limitations or standards for SO_2 and NO_X under the Acid Rain Program.

(d) Pursuant to 40 CFR 64.3(d), if a continuous emission monitoring system (CEMS) is required pursuant to other federal or state authority, the owner or operator shall use the CEMS to satisfy the requirements of CAM according to the criteria contained in 40 CFR 64.3(d).

The following table is used to identify the applicability of CAM to new and modified emission unit and each emission limitation or standard for a specified pollutant based on the criteria specified under 40 CFR 64.2:

Emission Unit/Pollutant	Control Device	Applicable Emission Limitation	Uncontrolled PTE (tons/year)	Controlled PTE (tons/year)	CAM Applicable (Y/N)	Large Unit (Y/N)
Combustion Turbine (19A, 19B, 19C, Unit 20) - VOC	OC	326 IAC 2-2	<100, each	--	N	--
Combustion Turbine (19A, 19B, 19C, Unit 20) - CO	OC	None	--	--	N [1]	--
Combustion Turbine (21A, 21B, 22A, 22B) - VOC	OC	326 IAC 2-2	≥100, each	<100, each	Y	N
Combustion Turbine (21A, 21B, 22A, 22B) - CO	OC	None	--	--	N [1]	--
Combustion Turbine (21A, 21B, 22A, 22B) - NOx	SCR	326 IAC 2-2 avoidance	>100, each	>100, each	N [2]	--

Under the Part 70 Permit program (40 CFR 70), PM is not a regulated air pollutant.

Uncontrolled PTE (tpy) and controlled PTE (tpy) are evaluated against the Major Source Threshold for each pollutant. Major Source Threshold for regulated air 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.

N	CAM does not apply for pollutant because the uncontrolled PTE of pollutant is less than the major source threshold.
N [1]	The control device is not required to comply with the applicable emission limitation or standard. Therefore, based on this evaluation, the requirements of 40 CFR Part 64, CAM, are not applicable.
N [2]	A continuous compliance determination method, which provides data either in units of the standard or correlated directly to the compliance limit, is already specified in the Part 70 permit. Therefore, the emission limitation or standard is exempt from the requirements of 40 CFR Part 64, CAM.

Controls: OC = Oxidation Catalyst, SCR = Selective Catalytic Reduction

Emission units without air pollution controls are not subject to CAM. Therefore, they are not listed.

Based on this evaluation, the requirements of 40 CFR Part 64, CAM, are applicable to each of the combustion turbines, identified as 21A, 21B, 22A, and 22B, which are considered as "other units" for VOC upon issuance of the Part 70 Permit Renewal. A CAM plan for VOC emissions from the combustion turbines must be submitted as part of the Part 70 Operating Permit Renewal application.

Acid Rain Permit

Pursuant to 40 CFR 72 through 40 CFR 78 and 326 IAC 21 (Acid Rain Program), the acid rain permit for this source is incorporated by reference into this Part 70 Permit. Pursuant to 326 IAC 21 (Acid Deposition

Control), the Permittee shall comply with all provisions of the Acid Rain permit issued for this source, and any other applicable requirements contained in 40 CFR 72 through 40 CFR 78.

Cross-State Air Pollutant Rule (CSAPR):

The preamble of the CSAPR regulations promulgated on August 8, 2011, states that the requirements established in the CSAPR trading program are applicable requirements that must be included in a source Title V permit pursuant to 40 CFR Part 70 and 71.

The CSAPR became effective on 1 January 2015 to reduce annual NOX emissions, ozone (O3) season NOX emissions, and annual SO2 emissions from fossil fuel-fired electric generating facilities in 28 states, including Indiana. Similar to the Acid Rain Program, CSAPR implemented a market-based approach for lowering emissions by imposing program-wide caps and providing an initial allocation of allowances to existing subject sources. Unlike the Acid Rain Program, CSAPR sets aside a percentage of the allowance budgets to provide to new units.

On March 15, 2021, EPA finalized the Revised Cross-State Air Pollution Rule (CSAPR) Update in order to resolve 21 states' outstanding interstate pollution transport obligations for the 2008 ozone National Ambient Air Quality Standards (NAAQS) (i.e., the 2008 ozone "good neighbor" provisions). Under this regulation, power plants in 12 states were required to participate in a new CASPR NOX Ozone Season Group 3 Trading Program (40 CFR 97, Subpart GGGGG). The new Group 3 trading program established in the rule was implemented starting May 1, 2021 (the first day of the 2021 ozone season), in which the Federal Implementation Plans (FIPs) would reduce NOx emissions from power plants in 12 states, including Indiana. The Group 3 Trading Program was stayed per 89 FR 87960, effective November 6, 2024.

On March 15, 2023, EPA finalized the Good Neighbor Plan to address 23 states' obligations to address interstate transport for the 2015 NAAQS. Under this new regulation, power plants in Indiana are required to participate in a revised version of the Group 3 Trading Program that was established under the Revised CSAPR Update rule. The Good Neighbor Plan (Group 3 Trading Program) was stayed per 89 FR 87960, effective November 6, 2024. EPA will implement this stay by recalling Group 3 Trading Program allowances and will record newly issued 2024 Group 2 allowances while the Good Neighbor Plan remains stayed. EPA further amended unit level allocations of emission allowances for Indiana EGUs on May 20, 2025 (90 FR 21423). The provisions of 40 CFR 97, Subpart EEEEE, applies while a stay is in place.

Pursuant to 40 CFR 97.404(a)(1), the natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B, are subject to the CSAPR NO_X Annual Trading Program because the requirements of 40 CFR Part 70 and 71 (Cross-State Air Pollution Rule (CSAPR)) apply to the natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B.

Pursuant to 40 CFR 97.804(a)(1), the natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B, are subject to the CSAPR NO_X Ozone Group 2 Trading Program because the requirements of 40 CFR Part 70 and 71 (Cross-State Air Pollution Rule (CSAPR)) apply to the natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B.

Pursuant to 40 CFR 97.604(a)(1), the natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B, are subject to the CSAPR SO2 Group 1 Trading Program because the requirements of 40 CFR Part 70 and 71 (Cross-State Air Pollution Rule (CSAPR)) apply to the natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B.

Transport Rule Monitoring Provisions

The combustion turbines, identified as 21A, 21B, 22A, and 22B, are subject to the requirements for the CSAPR NO_X Annual Trading Program, the CSAPR NO_X Ozone Season Trading Program, and the CSAPR SO_2 Group 1 Trading Program. The CSAPR subject unit and the unit-specific monitoring provisions at this source are identified in the following table:

Unit ID: 21A, 21B, 22A, and 22B					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR, Part 75, Subpart B (for SO_2 monitoring) & 40 CFR, Part 75, Subpart H (for NO_X Monitoring)	Excepted monitoring system requirements for gas-fired & oil-fired units pursuant to 40 CFR, Part 75, Appendix D	Excepted monitoring system requirements for gas-fired & oil-fired peaking units pursuant to 40 CFR, Part 75, Appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas-fired & oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR, Part 75, Subpart E
SO_2	----	X	----	----	----
NO_X	X	----	----	----	----
Heat input	----	X	----	----	----

(a) The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (CSAPR NO_X Annual Trading Program), 97.530 through 97.535 (CSAPR NO_X Ozone Season Trading Program), and 97.630 through 97.635 (CSAPR SO_2 Group 1 Trading Program), as applicable. The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable CSAPR trading programs.

(b) Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

(c) Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (CSAPR NO_X Annual Trading Program), 97.535 (CSAPR NO_X Ozone Season Trading Program), and 97.635 (CSAPR SO_2 Group 1 Trading Program), as applicable. The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(d) Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (CSAPR NO_X Annual Trading Program), 97.530 through 97.534 (CSAPR NO_X Ozone Season Trading Program), and 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program), as applicable, must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (CSAPR NO_X Annual Trading Program), 97.535 (CSAPR NO_X Ozone Season Trading Program), and 97.635 (CSAPR SO_2 Group 1 Trading Program), as applicable. The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(e) The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (CSAPR NO_X Annual Trading Program), 97.530 through 97.534 (CSAPR NO_X Ozone Season Trading Program), and 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program), as applicable, and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

State Rule Applicability - Entire Source

Due to this modification, state rule applicability has been reviewed as follows:

326 IAC 24 (Cross-State Air Pollutant Rule (CSAPR) Programs)
See the Cross-State Air Pollutant Rule (CSAPR) section above.

326 IAC 2-2 (PSD)
PSD applicability is discussed under the Permit Level Determination – PSD section and the Permit Level Determination - PSD Emissions Increase of this document.

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In order to render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2026 CCCT Project Modification permitted under SSM No. 073-49556-00008, the Permittee shall comply with the following:

(a) The combined PM emissions from the four (4) combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B shall not exceed 120.3 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(b) The combined NOx emissions from the four (4) combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B shall not exceed 1,566.3 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(c) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, the combined PM emissions from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 shall not exceed 91.0 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(d) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, the combined PM10 emissions from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 shall not exceed 345.0 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(e) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, the combined PM2.5 emissions from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 shall not exceed 292.0 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(f) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, the combined NOx emissions from Unit 17 and Unit 18 shall not exceed 1,560.0 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(g) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, the combined sulfuric acid mist (H2SO4) emissions from Unit 17 and Unit 18 shall not exceed 280.0 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

Compliance with these limits and Condition D.14.4, shall limit the potential to emit of PM, PM10, PM2.5, NOx, and H2SO4 to less than 25, 15, 10, 40, and 7 tons per twelve (12) consecutive month period, respectively, and shall render the requirements of 326 IAC 2-2 (Prevention of

Significant Deterioration (PSD)) not applicable to the 2026 CCCT Project modification permitted under SSM No. 073-49556-00008 for these regulated NSR pollutants.

326 IAC 2-2-3 (PSD Rule: Control Technology Review Requirements)
Pursuant to PSD/SSM 073-49556-000018 and to 326 IAC 2-2-3 (Control Technology Review Requirements), the Permittee shall comply with the following BACT limits:

Combustion Turbines (21A, 21B, 22A, and 22B)

VOC

(a) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 1.00 ppmvd @ 15% O_2 on 3-hour average basis, excluding during periods of startup and shutdown for the combustion turbines for both simple cycle and combined cycle operations.

(b) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 2.00 ppmvd @15% O_2 on 3-hour average basis, excluding during periods of startup and shutdown when the combined cycle turbines are operated with duct burners.

(c) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 9.60 lb/hr on a 3-hour average basis, excluding during periods of startup and shutdown, when operating in combined cycle mode without duct burner.

(d) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 15.40 lb/hr on a 3-hour average basis, excluding during periods of startup and shutdown, when operating in combined cycle mode with duct burner.

(e) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 9.10 lb/hr on a 3-hour average basis, excluding during periods of startup and shutdown, when operating in simple cycle mode.

(f) VOC emissions from the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall be controlled using an oxidation catalyst and conducting good combustion practices.

(g) Total VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, during any periods of startup and shutdown operation shall not exceed 25.6 tons per 12-month rolling.

GHGs

(a) CO_2 emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 1,170 lb/MW-hr (gross) per twelve (12) operating month period average when operating in simple cycle mode.

(b) CO_2 emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 800 lb/MW-hr (gross) per twelve (12) operating month period average when operating in combined cycle mode.

(c) CO_2e emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall be limited through the use of good combustion practices and energy efficient design.

(d) The total GHGs (CO2, CH4, and N2O) emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, when operating in simple cycle mode, including steady state operation and operation during any periods of startup and shutdown, shall not exceed 863,649 tons per twelve (12) consecutive month period with compliance determined at the end of each month (GWPs per 78 FR 71948).

(e) The total GHGs (CO2, CH4, and N2O) emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, when operating in combined cycle mode, including steady state operation and operation during any periods of startup and shutdown, shall not exceed 1,751,087 tons per twelve (12) consecutive month period with compliance determined at the end of each month (GWPs per 78 FR 71948).

Auxiliary Boilers (AUX1 and AUX2)

VOC

(a) VOC emissions from each auxiliary boilers AUX1 and AUX2 shall not exceed 5.5 lb/MMcf.

(b) VOC emissions from the auxiliary boilers, identified as AUX1 and AUX2, shall be controlled through the use of good combustion practices.

GHGs

(a) CO_2e emissions from each of the auxiliary boilers AUX1 and AUX2 shall not exceed 119,439 lb/MMcf (GWPs per 78 FR 71948).

(b) CO_2e emissions from each of the auxiliary boilers AUX1 and AUX2 shall be controlled through the use of natural gas fuel, implement efficient boiler design, and good combustion practices.

Diesel Emergency Generators (EDGCC1 and EDGCC2)

VOC

(a) VOC emissions from each emergency generators (EDGCC1 and EDGCC2) shall be controlled good combustion practices including the installation of an equipment design standard and compliance with the requirements of 40 CFR 60, Subpart IIII.

(b) NMHC + NOx emissions from each emergency generator (EDGCC1 and EDGCC2) shall not exceed 6.4 g/ kW-hr.

GHGs

(a) The CO_2e emissions from each emergency generator (EDGCC1 and EDGCC2) shall be controlled through the use of good combustion practices including the installation of an equipment design standard and the compliance of the 40 CFR Part 60 Subpart IIII.

(b) The CO_2e emissions from each emergency generator (EDGCC1 and EDGCC2) shall not exceed 163.6 lb/MMBtu (GWPs per 78 FR 71948).

Diesel Emergency Fire Pumps (FPCC1 and FPCC2)

VOC

(a) VOC emissions from each emergency fire pump (FPCC1 and FPCC2) shall be controlled good combustion practices including the installation of an equipment design standard and compliance with the requirements of 40 CFR 60, Subpart IIII.

(b) NMHC + NOx emissions from each emergency fire pump engine (FPCC1 and FPCC2) shall not exceed 6.4 g/ kW-hr.

GHGs

(a) The CO_2e emissions from each emergency fire pump (FPCC1 and FPCC2) shall be controlled through the use of good combustion practices including the installation of an equipment design standard and the compliance of the 40 CFR Part 60 Subpart IIII.

(b) The CO_2e emissions from each emergency fire pump (FPCC1 and FPCC2) shall not exceed 163.6 lb/MMBtu (GWPs per 78 FR 71948).

Dew Point Heater (DPH1)

VOC

(a) VOC emissions from the natural gas-fired dew point heater DPH1 shall not exceed 5.5 lb/MMcf.

(b) VOC emissions from the natural gas fired dew point heater DPH1 shall be controlled by good combustion practices.

(c) The Permittee shall only combust natural gas fuel in the dew point heater DPH1.

GHGs

(a) CO_2e emissions from the natural gas fired dew point heater DPH1 shall not exceed 119,439 lb/MMcf (GWPs per 78 FR 71948).

(b) GHG emissions from the natural gas fired dew point heater DPH1 shall be controlled by good combustion practices.

(c) The Permittee shall only combust natural gas fuel in the dew point heater DPH1.

Lube Oil Demister Vents (LOV21A, LOV21B, LOV22A, LOV22B, LOV21S, and LOV22S)

VOC

(a) VOC emissions from each of the lube oil demister vents shall be controlled through the use of demisters and good engineering design and operating practices.

CCCT - Circuit Breakers

GHGs

(a) The Permittee shall use a fully enclosed pressurized SF6 circuit breakers outfitted with density alarms for leak detection.

(b) The circuit breakers shall be designed to have a maximum SF6 leak rate not to exceed 0.5% per twelve (12) consecutive month period.

Natural Gas Piping Components *(CCCT - Piping Systems)*

VOC and GHGs

(a) The permittee shall implement an auditory/visual/olfactory (AVO) monitoring program for detecting leaks from the natural gas piping components installed as part of 2026 CCCT Project.

(b) AVO monitoring shall be performed in accordance with a written monitoring program.

*Diesel Storage Tank (*TKCC1)

VOC

(a) The permittee shall implement good equipment design and operating practices for the proposed diesel storage tank.

326 IAC 2-2-4 (Air Quality Analysis Requirements)
Pursuant to 326 IAC 2-2-4(a), the PSD application shall contain an analysis of ambient air quality in the area that the major modification would affect for each regulated NSR pollutant for which the modification would result in a significant net emissions increase. Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station has submitted an air quality analysis, which has been evaluated by IDEM's Technical Support and Modeling Section. See Appendix C to this Technical Support Document (TSD) for the PSD air quality analysis.

326 IAC 2-2-5 (Air Quality Impact Requirements)
(a) Pursuant to 326 IAC 2-2-5(d)(1), an air quality impact analysis shall be conducted in accordance with the following provisions:

(1) Any estimates of ambient air concentrations used in the demonstration process shall be based upon the applicable air quality models, databases, and other requirements specified in 40 CFR Part 51, Appendix W (Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Guideline on Air Quality Models).

(2) Where an air quality impact model specified in the guidelines in subdivision (1) is inappropriate, a model may be modified or another model substituted provided that all applicable guidelines are satisfied.

(3) Modifications or substitution of any model may only be done in accordance with guideline documents and with written approval from U.S. EPA and shall be subject to the public comment procedures set forth in 326 IAC 2-1.1-6.

See Appendix C to this Technical Support Document (TSD) for the PSD air quality analysis.

326 IAC 2-2-7 (Additional Analysis, Requirements)
Pursuant to 326 IAC 2-2-7(a) the Permittee shall provide an analysis of the impairment to visibility, soils, and vegetation. An analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the modification was performed. The results of the additional impact analysis concluded the modification will have no adverse impact on economic growth, soils, vegetation, and endangered or threatened species.

See Appendix C to this Technical Support Document (TSD) for the PSD air quality analysis.

326 IAC 2-2-8 (Source Obligation)
(a) Pursuant to 326 IAC 2-2-8(1), approval to construct shall become invalid if construction is not commenced within eighteen (18) months after receipt of the approval, if construction is discontinued for a period of eighteen (18) months or more, or if construction is not completed within a reasonable time.

(b) Approval for construction shall not relieve the Permittee of the responsibility to comply fully with applicable provisions of the state implementation plan and any other requirements under local, state, or federal law.

326 IAC 2-2-9 (Innovative Control Technology)
Pursuant to 326 IAC 2-2-9 the Permittee may request the commissioner in writing to approve a system of innovative control technologies as part of the PSD application for T 073-49556-00008.

326 IAC 2-2-10 (Source Information)
Pursuant to 326 IAC 2-2-10, the Permittee has submitted all information necessary to perform an analysis or make the determination required under 326 IAC 2-2.

326 IAC 2-2-12 (Permit Rescission)
Pursuant to 326 IAC 2-2-12, the permit issued under 326 IAC 2-2 shall remain in effect unless and until it is rescinded, modified, revoked, or it expires in accordance with 326 IAC 2-1.1-9.5 or 326 IAC 2-2-8.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The provisions of 326 IAC 2-4.1 apply to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants (HAP), as defined in 40 CFR 63.41, after July 27, 1997, unless the major source has been specifically regulated under or exempted from regulation under a NESHAP that was issued pursuant to Section 112(d), 112(h), or 112(j) of the Clean Air Act (CAA) and incorporated under 40 CFR 63. On and after June 29, 1998, 326 IAC 2-4.1 is intended to implement the requirements of Section 112(g)(2)(B) of the Clean Air Act (CAA).

The operation of the combustion turbines under the 2026 CCCT Project will emit 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, 326 IAC 2-4.1 would apply to the combustion turbines. However, pursuant to 326 IAC 2-4.1-1(b)(2), because the combustion turbines are specifically regulated under NESHAP 40 CFR 63, Subpart YYYY, which was issued pursuant to Section 112(d), 112(h), or 112(j) of the CAA, the combustion turbines are exempt from the requirements of 326 IAC 2-4.1.

326 IAC 2-6 (Emission Reporting)
This source is subject to the requirements of 326 IAC 2-6 (Emission Reporting), since it has the potential to emit NOx and SO2 equal to or greater than two thousand five hundred (2,500) tons per year and has the potential to emit PM10 equal to or greater than two hundred fifty (250) tons per year. Pursuant to 326 IAC 2-6-3(a)(1), the Permittee shall submit annually, by July 1, an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

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)

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 Jasper 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 Jasper County) is not subject to the requirements of 326 IAC 6.8 because it is not located in Lake County.

326 IAC 6.8 (Lake County: Fugitive Particulate Matter)
Pursuant to 326 IAC 6.8-10-1, this source (located in Jasper County) is not subject to the requirements of 326 IAC 6.8-10 because it is not located in Lake County.

State Rule Applicability – Individual Facilities

Due to this modification, state rule applicability has been reviewed as follows:

2026 CCCT Project

Natural Gas-fired Combustion Turbines 21A, 21B, 22A, and 22B

326 IAC 6-2-1 (Particulate Emission Limitations for Sources of Indirect Heating)
Pursuant to 326 IAC 6-2-1(a), the natural gas-fired combustion turbines, identified as 21A, 21B, 22A, and 22B, are not subject to 326 IAC 6-2 because they are not indirect source of heating units.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
The natural gas-fired combustion turbines, identified as 21A, 21B, 22A, and 22B, are exempt from the requirements of 326 IAC 6-3 because, pursuant to 326 IAC 1-2-59, liquid and gaseous fuels and combustion air are not considered parts of the process weight.

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations
The natural gas-fired combustion turbines, identified as 21A, 21B, 22A, and 22B, are not subject to 326 IAC 326 IAC 7-1.1 because although each combustion turbine has a potential to emit sulfur dioxide (SO2) greater than 25 tons per year or 10 pounds per hour, these units do not combust coal or fuel oil.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
The natural gas-fired combustion turbines, identified as 21A, 21B, 22A, and 22B, are subject to the requirements of 326 IAC 8-1-6, because they were constructed after January 1, 1980, and each combustion turbine has unlimited VOC potential emissions equal to or greater than twenty-five (25) tons per year, and the combustion turbines are not regulated by other rules in 326 IAC 8. Therefore, a Best Available Control Technology (BACT) analysis was required for the combustion turbines (see Appendix B of this TSD).

According to the PSD BACT analysis contained in Appendix B of this TSD, IDEM, OAQ has determined that those requirements will also satisfy the requirements of 326 IAC 8-1-6.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
The requirements of 326 IAC 9-1 do not apply to the natural gas-fired combustion turbines, identified as 21A, 21B, 22A, and 22B, because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

326 IAC 10-2 (NO_x Emissions from Large Affected Units)
Pursuant to 326 IAC 1021(a)(1), the natural gas-fired combustion turbines, identified as Units 21A, 21B, 22A, and 22B are not subject to the requirements of 326 IAC 102 because they are subject to the CSAPR NO_x Ozone Season Group 2 Trading Program established under 40 CFR 97, Subpart EEEEE.

326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)
The requirements of 326 IAC 10-3 do not apply to the natural gas-fired combustion turbines, identified as 21A, 21B, 22A, and 22B, since these units are not blast furnace gas-fired boilers, Portland cement kilns, or facilities specifically listed under 326 IAC 10-3-1(a)(2).

326 IAC 3-5 (Continuous Monitoring Emissions)
Pursuant to 326 IAC 3-5-1(a), the requirements of 326 IAC 3-5 are applicable to the natural gas-fired combustion turbines, identified as 21A, 21B, 22A, and 22B, because these turbines are required to perform continuous emission monitoring system(s) (CEMS) under 326 IAC 12 (40 CFR 60.334(b)). A continuous monitoring system for NOx shall be installed, calibrated, operated, and maintained to measure NOx emissions.

Auxiliary Boilers (AUX1 and AUX2), Dew Point Heater (DPH1), and Natural Gas-fired Heat Recovery Steam Generator (HRSG) with Duct Burner

326 IAC 6-2-4 (Particulate Matter Emission Limitations for Sources of Indirect Heating)
Pursuant to 326 IAC 6-2-1(d), indirect heating facilities which received permit to construct after September 21, 1983 are subject to the requirements of 326 IAC 6-2-4.

The particulate matter emissions (Pt) from the auxiliary boilers (AUX1 and AUX2), dew point heater (DPH1), and heat recovery steam generator (HRSG) with duct burner shall be limited by the following equation:

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

Where:

Pt = Pounds of particulate matter emitted per million British thermal units (lb/MMBtu).

Q = Total source maximum operating capacity rating in MMBtu/hr heat input. The maximum operating capacity rating is defined as the maximum capacity at which the facility is operated or the nameplate capacity, whichever is specified in the facility's permit application, except when some lower capacity is contained in the facility's operation permit; in which case, the capacity specified in the operation permit shall be used.

Pursuant to 326 IAC 6-2-4(a), for Q greater than or equal to 10,000 MMBtu/hr, Pt shall not exceed 0.1 lb/MMBtu.

Indirect Heating Units Which Began Operation After September 21, 1983						
Facility	Construction Date (Removal Date)	Operating Capacity (MMBtu/hr)	Q (MMBtu/hr)	Calculated Pt (lb/MMBtu)	Particulate Limitation, (Pt) (lb/MMBtu)	PM EF based on AP-42 (lb/MMBtu)
Units Operating Prior to 9/21/1983			12,584	--	--	--
Temporary Boiler	2020	99.9	12,683.9	0.09	0.1	0.002

Indirect Heating Units Which Began Operation After September 21, 1983						
Facility	Construction Date (Removal Date)	Operating Capacity (MMBtu/hr)	Q (MMBtu/hr)	Calculated Pt (lb/MMBtu)	Particulate Limitation, (Pt) (lb/MMBtu)	PM EF based on AP-42 (lb/MMBtu)
Auxiliar Boiler AUX1	Approved in 2026 for construction	115	16,889.9	0.09	0.1	0.002
Auxiliar Boiler AUX2		115		0.09	0.1	0.002
Dew Point Heater DPH1		28		0.09	0.1	0.002
Four (4) HRSG with Duct Burners		987, each		0.09	0.1	0.002
Where: Q = Includes the capacity (MMBtu/hr) of the new unit(s) and the capacities for those unit(s) which were in operation at the source at the time the new unit(s) was constructed.						
Note: Emission units shown in strikethrough were subsequently removed from the source. The effect of removing these units on "Q" is shown in the year the boiler was removed.						

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
Pursuant to 326 IAC 6-3-1(b)(1), the auxiliary boilers (AUX1 and AUX2), dew point heater (DPH1), and heat recovery steam generator (HRSG) with duct burner are not subject to the requirements of 326 IAC 6-3, since these units are combustion for indirect heating units.

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations
The auxiliary boilers (AUX1 and AUX2), dew point heater (DPH1), and heat recovery steam generator (HRSG) with duct burner are not subject to 326 IAC 326 IAC 7-1.1 because each unit has a potential to emit (or limited potential to emit) sulfur dioxide (SO2) less than 25 tons per year or 10 pounds per hour.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
Even though, the auxiliary boilers (AUX1 and AUX2), dew point heater (DPH1), and heat recovery steam generator (HRSG) with duct burner were constructed after January 1, 1980, they are not subject to the requirements of 326 IAC 8-1-6 because each unit has unlimited VOC potential emissions less than twenty-five (25) tons per year.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
The requirements of 326 IAC 9-1 do not apply to the auxiliary boilers (AUX1 and AUX2), dew point heater (DPH1), and heat recovery steam generator (HRSG) with duct burner because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)
The requirements of 326 IAC 10-3 do not apply to the auxiliary boilers (AUX1 and AUX2), dew point heater (DPH1), and heat recovery steam generator (HRSG) with duct burner since these units are not blast furnace gas-fired boilers, Portland cement kilns, or facilities specifically listed under 326 IAC 10-3-1(a)(2).

Cooling Towers (CTH1 and CTH2)

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
Pursuant to 326 IAC 6-3-1(b)(11), the mechanical draft cooling towers (CTH1 and CTH2) are not subject to the requirements of 326 IAC 6-3, since these units are noncontact cooling towers.

Diesel Emergency Generators (EDGCC1 and EDGCC2)

326 IAC 6-2-1 (Particulate Emission Limitations for Sources of Indirect Heating)
Pursuant to 326 IAC 6-2-1(a), the diesel emergency generators (EDGCC1 and EDGCC2) are not subject to the requirments of 326 IAC 6-2 because they are not indirect source of heating units.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
The diesel emergency generators (EDGCC1 and EDGCC2) are exempt from the requirements of 326 IAC 6-3 because, pursuant to 326 IAC 1-2-59, liquid and gaseous fuels and combustion air are not considered parts of the process weight.

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations
The diesel emergency generators (EDGCC1 and EDGCC2) are not subject to 326 IAC 326 IAC 7-1.1 because each unit has a potential to emit (or limited potential to emit) sulfur dioxide (SO2) less than 25 tons per year or 10 pounds per hour.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
Even though, the diesel emergency generators (EDGCC1 and EDGCC2) were constructed after January 1, 1980, they are not subject to the requirements of 326 IAC 8-1-6 because each unit has unlimited VOC potential emissions less than twenty-five (25) tons per year.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
The requirements of 326 IAC 9-1 do not apply to the diesel emergency generators (EDGCC1 and EDGCC2), because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)
The requirements of 326 IAC 10-3 do not apply to the diesel emergency generators (EDGCC1 and EDGCC2), since these units are not blast furnace gas-fired boilers, Portland cement kilns, or facilities specifically listed under 326 IAC 10-3-1(a)(2).

Diesel Emergency Fire Pumps (FPCC1 and FPCC2)

326 IAC 6-2-1 (Particulate Emission Limitations for Sources of Indirect Heating)
Pursuant to 326 IAC 6-2-1(a), the diesel emergency fire pumps (FPCC1 and FPCC2) are not subject to the requirments of 326 IAC 6-2 because they are not indirect source of heating units.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
The diesel emergency fire pumps (FPCC1 and FPCC2) are exempt from the requirements of 326 IAC 6-3 because, pursuant to 326 IAC 1-2-59, liquid and gaseous fuels and combustion air are not considered parts of the process weight.

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations
The diesel emergency fire pumps (FPCC1 and FPCC2) are not subject to 326 IAC 326 IAC 7-1.1 because each unit has a potential to emit (or limited potential to emit) sulfur dioxide (SO2) less than 25 tons per year or 10 pounds per hour.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
Even though, the diesel emergency fire pumps (FPCC1 and FPCC2) were constructed after January 1, 1980, they are not subject to the requirements of 326 IAC 8-1-6 because each unit has unlimited VOC potential emissions less than twenty-five (25) tons per year.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
The requirements of 326 IAC 9-1 do not apply to the diesel emergency fire pumps (FPCC1 and FPCC2), because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum

fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)
The requirements of 326 IAC 10-3 do not apply to the diesel emergency fire pumps (FPCC1 and FPCC2), since these units are not blast furnace gas-fired boilers, Portland cement kilns, or facilities specifically listed under 326 IAC 10-3-1(a)(2).

Lube Oil Demister Vents (LOV21A, LOV21B, LOV22A, LOV22B, LOV21S, and LOV22S)

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
Pursuant to 326 IAC 6-3-1(b)(14), the lube oil demister vents (LOV21A, LOV21B, LOV22A, LOV22B, LOV21S, and LOV22S) are not subject to the requirements of 326 IAC 6-3, since each has potential emissions less than five hundred fifty-one thousandths (0.551) pound per hour.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
Even though, this lube oil demister vents (LOV21A, LOV21B, LOV22A, LOV22B, LOV21S, and LOV22S) were constructed after January 1, 1980, they are not subject to the requirements of 326 IAC 8-1-6 because each has unlimited VOC potential emissions less than twenty-five (25) tons per year.

Storage Tank (TKCC1)

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
Even though, this storage tank (TKCC1) was constructed after January 1, 1980, it is not subject to the requirements of 326 IAC 8-1-6 because its unlimited VOC potential emissions are less than twenty-five (25) tons per year.

326 IAC 8-4-3 (Petroleum Liquid Storage Facilities)
The storage tank (TKCC1) is not subject to the requirements of 326 IAC 8-4-3 because it has a maximum capacity less than one hundred fifty thousand (150,000) liters (thirty-nine thousand (39,000) gallons).

Natural Gas Piping System (CCCT - Piping System)

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
Even though, the natural gas piping system (CCCT - Piping System) was constructed after January 1, 1980, it is not subject to the requirements of 326 IAC 8-1-6 because its unlimited VOC potential emissions are 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 modification are as follows:

(1) Compliance with the proposed PM emission limitation from each combustion turbine (21A, 21B, 22A, and 22) shall be determined using the following equation:

$$E_{PM} = \sum_{i=1}^{12}\left(\sum_{n}\frac{[(ER_S * H_S) + (ER_{S(SU/SD)} * Evt_S)]}{2000} + \sum_{n}\frac{[(ER_C * H_C) + (ER_{CDB} * H_{CDB}) + (ER_{C(SU/SD)} * Evt_C)]}{2000}\right)$$

Where:

E_{PM} = Total PM emissions (tons/year) form the combustion turbines 21A, 21B, 22A, and 22B

ER_S = 8.05 lb/hr, PM emission rate during simple cycle steady state operation for the combustion turbines 21A, 21B, 22A, and 22B or value established in latest stack test

ER_C = 6.60 lb/hr, PM emission rate during combined cycle steady state operation without duct burner for the combustion turbines 21A, 21B, 22A, and 22B or value established in latest stack test

ER_{CDB} = 12.30 lb/hr, PM emission rate during combined cycle steady state operation with duct burner for the combustion turbines 21A, 21B, 22A, and 22B or value established in latest stack test

$ER_{S(SU/SD)}$ = 8.55 lb/event, PM emission rate during startup/shutdown events in simple cycle for the combustion turbines 21A, 21B, 22A, and 22B

$ER_{C(SU/SD)}$ = 17.10 lb/event, PM emission rate during startup/shutdown events in combined cycle operation for the combustion turbines 21A, 21B, 22A, and 22B

Evt_S = Number of events per month during simple cycle operation for the combustion turbines 21A, 21B, 22A, and 22B, where one event is a startup and shutdown cycle

Evt_C = Number of events per month during combined cycle operation for the combustion turbines 21A, 21B, 22A, and 22B, where one event is a startup and shutdown cycle

H_S = Number of hours during simple cycle operation per month for the combustion turbines 21A, 21B, 22A, and 22B

H_C = Number of hours during combined cycle operation without duct burner per month for the combustion turbines 21A, 21B, 22A, and 22B

H_{CDB} = Number of hours during combined cycle operation with duct burner per month for the combustion turbines 21A, 21B, 22A, and 22B

i = Each calendar month within the twelve (12) consecutive month period

n = Each combustion turbine Unit (21A, 21B, 22A, and 22B)

(2) Compliance with the PSD BACT limit for VOC for startup and shutdown operation for each combustion turbine (21A, 21B, 22A, and 22B) shall be determined using the following equation:

$$E_{VOC} = \sum_{i=1}^{12}\left(\frac{[(ER_{S(SU/SD)} * Evt_S)]}{2000} + \frac{[(ER_{C(SU/SD)} * Evt_C)]}{2000}\right)$$

Where:

E_{VOC} = Total VOC emissions (tons/year) form the combustion turbine

$ER_{S(SU/SD)}$ = 140 lb/event, VOC emission rate during startup/shutdown events in simple cycle for the combustion turbine

$ER_{C(SU/SD)}$ = 140 lb/event, VOC emission rate during startup/shutdown events in combined cycle operation for the combustion turbine

Evt_S = Number of events per month during simple cycle operation for the combustion turbine, where one event is a startup and shutdown cycle
Evt_C = Number of events per month during combined cycle operation for the combustion turbine, where one event is a startup and shutdown cycle
i = Each calendar month within the twelve (12) consecutive month period

(3) Compliance with the PSD BACT limit for GHGs from each combustion turbine (21A, 21B, 22A, and 22B), when operating in simple cycle mode, shall be determined using the following equation:

$$E_{GHGs} = \sum_{i=1}^{12} \left(\frac{[(ER_S * H_S) + (ER_{S(SU/SD)} * Evt_S)]}{2000} \right)$$

Where:

E_{GHGs} = Total GHGs emissions (tons/year) form each combustion turbine
ER_S = 446,445 lb/hr, GHGs emission rate during simple cycle normal operation for the combustion turbine, or value established in latest stack test
$ER_{S(SU/SD)}$ = 446,445 lb/event, GHGs emission rate during startup/shutdown events in simple cycle for the combustion turbine
Evt_S = Number of events per month during simple cycle operation for the combustion turbine, where one event is a startup and shutdown cycle
H_S = Number of hours during simple cycle operation per month for the combustion turbine
i = Each calendar month within the twelve (12) consecutive month period

(4) Compliance with the PSD BACT limit for GHGs from each combustion turbine (21A, 21B, 22A, and 22B) when operating in combined cycle mode shall be determined using the following equation:

$$E_{GHGs} = \sum_{i=1}^{12} \left(\frac{[(ER_C * H_C) + (ER_{CDB} * H_{CDB}) + (ER_{C(SU/SD)} * Evt_C)]}{2000} \right)$$

Where:

E_{GHGs} = Total GHGs emissions (tons/year) form each combustion turbine
ER_C = 473,770 lb/hr, GHGs emission rate during combined cycle normal operation without duct burner for the combustion turbine, or value established in latest stack test
ER_{CDB} = 601,899 lb/hr, GHGs emission rate during combined cycle normal operation with duct burner for the combustion turbine, or value established in latest stack test
$ER_{C(SU/SD)}$ = 473,770 lb/event, GHGs emission rate during startup/shutdown events in combined cycle operation for the combustion turbine
Evt_C = Number of events per month during combined cycle operation for the combustion turbine, where one event is a startup and shutdown cycle
H_C = Number of hours during combined cycle operation without duct burner per month for the combustion turbine
H_{CDB} = Number of hours during combined cycle operation with duct burner per month for the combustion turbine
i = Each calendar month within the twelve (12) consecutive month period

(5) Compliance with PM emissions limit from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 shall be determined as follows:

$$PM = \sum_{i=1}^{12} (\mathrm{EU17} + \mathrm{EU18} + \mathrm{ECU17} + \mathrm{ECU18})$$

where:

PM = Total PM emissions (tons/month) from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18
i = Each calendar month within the twelve (12) consecutive month period
E_{U17} = PM emissions (tons/month) from Unit 17 calculated using the CEMS data
E_{U18} = PM emission (tons/month) from Unit 18 calculated using the CEMS data
E_{CU17} = PM emission (tons/month) from Colling Tower Unit 17 calculated using the following equation:

E_{CU17} = EF * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

E_{CU18} = PM emission (tons/month) from Colling Tower Unit 18 calculated using the following equation:

E_{CU17} = EF * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

(6) Compliance with PM10 emissions limit from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 shall be determined as follows:

$$PM10 = \sum_{i=1}^{12} (\mathrm{EU17} + \mathrm{EU18} + \mathrm{ECU17} + \mathrm{ECU18})$$

where:

PM10 = Total PM10 emissions (tons/month) from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18
i = Each calendar month within the twelve (12) consecutive month period
E_{U17} = PM10 emissions (tons/month) from Unit 17 calculated using the CEMS data.
E_{U18} = PM10 emission (tons/month) from Unit 18 calculated using the CEMS data.
E_{CU17} = PM10 emission (tons/month) from Colling Tower Unit 17 calculated using the following equation:

E_{CU17} = EF * 70% * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
70% = % PM to PM10 ratio according to California SCAQMD CEIDARS
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

E_{CU18} = PM emission (tons/month) from Colling Tower Unit 18 calculated using the following equation:

E_{CU17} = EF * 70% * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
70% = % PM to PM10 ratio according to California SCAQMD CEIDARS
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

(7) Compliance with PM2.5 emissions limit from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 shall be determined as follows:

$$PM2.5 = \sum_{i=1}^{12} (\mathrm{EU17} + \mathrm{EU18} + \mathrm{ECU17} + \mathrm{ECU18})$$

where:

PM2.5 = Total PM2.5 emissions (tons/month) from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18
i = Each calendar month within the twelve (12) consecutive month period
E_{U17} = PM2.5 emissions (tons/month) from Unit 17 calculated using the CEMS data
E_{U18} = PM2.5 emission (tons/month) from Unit 18 calculated using the CEMS data
E_{CU17} = PM2.5 emission (tons/month) from Colling Tower Unit 17 calculated using the following equation:

E_{CU17} = EF * 40% * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
40% = % PM to PM2.5 ratio according to California SCAQMD CEIDARS
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

E_{CU18} = PM2.5 emission (tons/month) from Colling Tower Unit 18 calculated using the following equation:

E_{CU17} = EF * 40% * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
40% = % PM to PM2.5 ratio according to California SCAQMD CEIDARS
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

(8) Compliance with combined NOx emissions limit from Unit 17 and Unit 18 shall be determined using the continuous monitoring systems data.

(9) Compliance with combined sulfuric acid mist (H2SO4) emissions limit from Unit 17 and Unit 18 shall be determined by calculating H2SO4 emissions using the emissions calculations used to calculate H2SO4 release for the Toxics Release Inventory (TRI) program.

Testing Requirements:

Summary of Testing Requirements					
Emission Unit	**Control Device**	**Timeframe for Testing or Date of Initial Valid Demonstration)**	**Pollutant/ Parameter**	**Frequency of Testing**	**Authority**
Combustion Turbines 21A, 21B, 22A, and 22B	Oxidation Catalysts (OXCA21A, OXCA21B, OXCA22A, OXCA22B)	180*	VOC (1.0 ppmvd @ 15% O_2)[1]	Every 5 years	326 IAC 2-2-3 326 IAC 2-1.1-11
			VOC (2.0 ppmvd @ 15% O_2)[2]		
			VOC (9.60 lb/hr)[1]		
			VOC (15.40 lb/hr)[2]		
			VOC (9.10 lb/hr)[3]		
	N/A	180*	NOx (15 ppm)	one-time	40 CFR 60, Subpart KKKK
	OXCA21A, OXCA21B, OXCA22A, OXCA22B	180*	CO (16.80 lb/hr)[1]	Every 5 years	326 IAC 2-1.1-11
			CO (21.50 lb/hr)[2]		
			CO (15.90 lb/hr)[3]		

* No later than 180 days after startup of combustion turbines 21A, 21B, 22A, and 22B
1 When operating in combined cycle mode without duct burner
2 When operating in combined cycle mode with duct burner
3 When operating in simple cycle mode

Continuous Emissions Monitoring System (CEMS) and Continuous Opacity Monitoring (COM) Requirements:

Emission Unit	**Type of Continuous Monitor (Pollutant Monitored)**	**Applicable Rule or Authority**
Turbines (21A, 21B, 22A, and 22B)	CEMS for NOx	326 IAC 3-5 326 IAC 2-7-6(1) & (6) 326 IAC 2-2-3(PSD) 40 CFR 60, Subpart KKKK

(b) The Compliance Monitoring Requirements applicable to this proposed modification are as follows:

Control Device	**Type of Parametric Monitoring**	**Frequency**	**Range or Specification**
Oxidation Catalysts (OXCA21A,OXCA21B, OXCA22A, OXCA22B) for Combustion Turbines (21A, 21B, 22A, 22B)	3-hour average oxidizer temperature monitoring	Continuous	At or above 500 °F from startup (or permit issuance) until stack test results are available, then at or above the value established in the most recent compliant stack test
	Catalyst Sampling	Annually	Verify that it is operated and maintained per manufacturer's specifications

These monitoring conditions are necessary because the oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, OXCA22B) for the combustion turbines (21A, 21B, 22A, and 22B) must operate properly to assure compliance with 326 IAC 2-2-3 (Prevention of Significant Deterioration).

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 listed below are due to the proposed modification. Deleted language appears as ~~strikethrough~~ text and new language appears as **bold** text (these changes may include Title I changes):

(1) IDEM OAQ has updated the descriptions of the combustion turbines units 19A, 19B, 19C, and 20 to include the oxidation catalysts as control device in Sections A.2, D.13 of the permit.

(2) IDEM OAQ has added the descriptions of the new combustion turbines 21A, 21B, 22A, and 22B and other ancillary emission units in Sections A.2 and A.3 of the permit.

(3) IDEM OAQ has removed Section D.0 from the permit because the facility is a major source of HAPs.

(4) IDEM OAQ has included the new emission limitations, compliance determinations, and reporting requirements for operations of Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 in Section D.3 of the permit.

(5) IDEM OAQ has included the applicable requirements concerning the proposed new combustion turbines 21A, 21B, 22C, and 22B in Section D.14 of the permit.

(6) IDEM OAQ has included the applicable requirements concerning the proposed auxiliary boilers, dew point heater, emergency generators, emergency fire pumps, mechanical cooling towers, diesel storage tank, lube oil demister vents, circuit breakers, and piping systems in Section D.15 of the permit.

(7) IDEM OAQ has updated Sections E.1, E.10, E.11, and H to update the description of the combustion turbines 19A, 19B, 19C, 20, and include the description and applicable requirements of the new combustion turbines 21A, 21B, 22A, and 22B.

(8) IDEM OAQ has updated Condition H.10 of the permit to add the TR monitoring provisions for the new combustion turbines 21A, 21B, 22A, and 22B.

(9) IDEM OAQ has updated Section E.6 of the permit to include the applicable requirements of 40 CFR 60, Subpart IIII concerning the proposed new emergency generators and fire pumps.

(10) IDEM OAQ has updated Section E.9 of the permit to include the applicable requirements of 40 CFR 63, Subpart ZZZZ concerning the proposed new emergency generators and fire pumps.

(11) IDEM OAQ has added Section E.12 to the permit to include the applicable requirements of 40 CFR 60, Subpart Db concerning the proposed new auxiliary boilers.

(12) IDEM OAQ has added Section E.13 to the permit to include the applicable requirements of 40 CFR 60, Subpart Dc concerning the proposed new dew-point heater.

(13) IDEM OAQ has added Section E.14 to the permit to include the applicable requirements of 40 CFR 60, Subpart KKKK concerning the proposed new combustion turbines.

(14) IDEM OAQ has added Section E.15 to the permit to include the applicable requirements of 40 CFR 63, Subpart DDDDD concerning the proposed new auxiliary boilers and dew point heater.

(15) IDEM OAQ has added reporting tables for PM and NOx emissions from the new combustion turbines 21A, 21B, 22A, and 22B.

(16) IDEM OAQ has removed reporting table for single HAP and total HAPs from the entire source have been removed from the permit since this source becomes Major source of HAPs and longer needs to limit its HAPs emissions.

(17) IDEM OAQ has revised the permit to change the word "normal" operation for combustion turbines to "steady state" operation.

(18) IDEM OAQ has included a new condition as D.13.6 in order to include the definition of startup and shutdown conditions.

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

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(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a rated maximum heat input capacity of 519 MMBtu per hour, each using **oxidation catalyst as control and** CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR 60, Subpart KKKK these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa these units are intermediate load affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a rated maximum heat input capacity of 2,416 MMBtu per hour, using **oxidation catalyst as control and** CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR 60, Subpart KKKK this unit is an affected facility]
[Under 40 CFR 60, Subpart TTTTa this unit is an intermediate load affected facility]
[Under 40 CFR 63, Subpart YYYY, this unit is an affected source]

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(o) Four (4) natural gas-fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a rated maximum nominal capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a rated maximum heat input of 987 MMBtu per hour, using dry low-NOx combustors and voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may

also operate as simple cycle combustion turbines and exhaust to bypass stacks (S21Asc, S21Bsc, S22Asc, and S22Bsc).

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(p) Two (2) natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, approved in 2026 for construction, each with a rated maximum capacity of 115 MMBtu per hour, using low NOx burners, and exhausting to stacks SAUX1 and SAUX2.

[Under 40 CFR 60, Subpart Db, these units are affected facilities]
[Under 40 CFR 63, Subpart DDDDD, these units are affected sources]

(q) One (1) natural gas-fired dew point heater, identified as DPH1, approved in 2026 for construction, with a rated maximum capacity of 28 MMBtu per hour, and exhausting to stack SDPH1.

[Under 40 CFR 60, Subpart Dc, this unit is an affected facility]
[Under 40 CFR 63, Subpart DDDDD, this unit is an affected source]

(r) Two (2) 2,500 kW diesel-fired certified emergency generators, identified as EDGCC1 and EDGCC2, approved in 2026 for construction, each with a rated maximum capacity of 3,353 hp, and exhausting to stacks SEDGCC1 and SEDGCC2.

[Under 40 CFR Part 60, Subpart IIII, these units are affected facilities]
[Under 40 CFR Part 63, Subpart ZZZZ, these units are affected sources]

(s) Two (2) 244 kW diesel-fired certified emergency fire pumps, identified as FPCC1 and FPCC2, approved in 2026 for construction, each with a rated maximum capacity of 327 hp, and exhausting to stacks SFPCC1 and SFPCC2.

[Under 40 CFR Part 60, Subpart IIII, these units are affected facilities]
[Under 40 CFR Part 63, Subpart ZZZZ, these units are affected sources]

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

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(j) Two (2) mechanical draft cooling towers, identified as CTH1 and CTH2, approved in 2026 for construction, each with a rated maximum circulation of 280,000 gallons of water per minute, TDS of 2,000 ppm, and total drift loss of 0.0005%.

(k) One (1) diesel storage tank, identified as TKCC1, approved in 2026 for construction, with a design storage capacity of 5,000 gallons and rated throughput of 130,000 gallons per year, and exhausting outdoors.

(l) Six (6) lube oil demister vents, identified as LOV21A, LOV21B, LOV22A, LOV22B, LOV21S, and LOV22S, approved in 2026 for construction, each with a vent flow rate of 500 cfm.

(m) High Voltage Electric Switchgear Containing Sulfur Hexafluoride (SF6), identified as CCCT - Circuit Breakers, approved in 2026 for construction.

(n) High Voltage Electric Switchgear Containing Sulfur Hexafluoride (SF6), identified as Peaker - Circuit Breakers.

(o) Natural gas piping components, identified as CCCT - Piping Systems, including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections.

(p) Natural gas piping components, identified as Peaker - Piping Systems, including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections.

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~~SECTION D.0 EMISSIONS UNIT OPERATION CONDITIONS~~

~~Emissions Unit Description:~~

~~Entire Source~~

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

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

~~D.0.1 Hazardous Air Pollutants (HAP) Minor Limits [40 CFR 63] [326 IAC 20]~~

~~Pursuant to SSM No. 073-47965-00008 and in order to render the source an area source of HAP emissions under Section 112 of the Clean Air Act (CAA), prior to the startup, as defined at 40 CFR 63.2, of the natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, 19C, and Unit 20, and the emergency generator EDG1 and emergency fire pump FP1, the Permittee shall comply with following:~~

~~(a) The combined total HAPs emissions from the combustion turbines (16A, 16B, 19A, 19B, 19C, and Unit 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 25 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.~~

~~(b) The combined formaldehyde emissions from the combustion turbines (16A, 16B, 19A, 19B, 19C, and Unit 20), temporary boiler, 334 HP diesel fire pump, emergency generator (EDG1), and emergency fire pump (FP1) shall be less than 10 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.~~

~~(c) Upon the commencement of operation of the natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, 19C, and Unit 20, the two (2) dry bottom pulverized coal-fired boilers, identified as Unit 17 and Unit 18, shall be permanently shutdown and subsequently decommissioned from the source.~~

~~(d) The limits in paragraphs (a) and (b) will be effective after the permanent shutdown and decommissioning of the two (2) dry bottom pulverized coal-fired boilers, identified as Unit 17 and Unit 18 and the start of operation of the natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, 19C, and Unit 20.~~

~~Compliance with these limits, combined with the potential to emit HAP from all other emission units at the source, shall limit the source-wide potential to emit single HAP to less than 10 tons per twelve (12) consecutive month period and the source-wide potential to emit total HAPs to less than 25 tons per twelve (12) consecutive month period, and shall render the source an area source of HAP emissions under Section 112 of the Clean Air Act (CAA).~~

~~Compliance Determination Requirements~~

~~D.0.2 Compliance Determination for Combined Total HAP~~

~~In order to determine compliance with Condition D.0.1(a), the combined total HAP emissions from the entire source shall be determined using the following equation:~~

$$E_{THAP} = \sum_{i=1}^{12}\left(\sum_{n}\frac{EF_{n19} * HI_{19A} + EF_{n19} * HI_{19B} + EF_{n19} * HI_{19C} + EF_{nU20} * HI_{U20} + EF_{n16} * HI_{16A} + EF_{n16} * HI_{16B} + EF_{nTB} * NT_{TB} + EF_{n350FP} * DT_{350FP} + EF_{nFP1} * DT_{FP1} + EF_{nEDG1} * DT_{EDG1}}{2000}\right)$$

~~Where:~~

~~E_{THAP} = Combined total HAP emissions (tons/month)~~
~~HI_{19A} = Heat input from turbine Unit 19A (MMBtu/month)~~
~~HI_{19B} = Heat input from turbine Unit 19B (MMBtu/month)~~
~~HI_{19C} = Heat input from turbine Unit 19C (MMBtu/month)~~
~~HI_{U20} = Heat input from turbine Unit 20 (MMBtu/month)~~
~~HI_{16A} = Heat input from turbine Unit 16A (MMBtu/month)~~
~~HI_{16B} = Heat input from turbine Unit 16B (MMBtu/month)~~
~~NT_{TB} = Natural gas throughput from temporary boiler (MMscf/month)~~
~~DT_{350FP} = Diesel fuel throughput from 350 diesel fire pump (gallons/month)~~
~~DT_{EDG1} = Diesel fuel throughput from emergency diesel generator EDG1 (gallons/month)~~
~~DT_{FP1} = Diesel fuel throughput from emergency diesel fire pump FP1 (gallons/month)~~
~~EF_{n19} = Emission factors (in lb/MMBtu) for every single HAP from Units 19A, 19B, and 19C~~
~~EF_{nU20} = Emission factors (in lb/MMBtu) for every single HAP from Unit 20~~
~~EF_{n16} = Emission factors (in lb/MMBtu) for every single HAP from Units 16A and 16B~~
~~EF_{nTB} = Emission factors (in lb/MMscf) for every single HAP from temporary boiler~~
~~EF_{n350FP} = Emission factors (in lb/gallon) for every single HAP from 350 HP diesel fire pump~~
~~EF_{nEDG1} = Emission factors (in lb/gallon) for every single HAP from diesel emergency generator EDG1~~
~~EF_{nFP1} = Emission factors (in lb/gallon) for every single HAP from diesel emergency fire pump FP1~~
~~i = Each calendar month within the twelve (12) consecutive month period~~
~~n = Every single HAP emitted by emission units included in the HAP limit~~

~~D.0.3 Compliance Determination for Combined Formaldehyde~~

~~In order to determine compliance with Condition D.0.1(b), the combined single HAP (formaldehyde) emissions from the entire source shall be determined using the following equation:~~

$$\sum_{i=1}^{12} E_{Single\ HAP\ (Formaldeayde)} = \frac{ER_{19} * HR_{19A} + ER_{19} * HR_{19B} + ER_{19} * HR_{19C} + ER_{U20} * HR_{U20} + EF_{16} * HI_{16A} + EF_{16} * HI_{16B} + EF_{TB} * NT_{TB} + EF_{350FP} * DT_{350FP} + EF_{FP1} * DT_{FP1} + EF_{EDG1} * DT_{EDG1}}{2000}$$

~~Where:~~

~~$E_{Single\ HAP\ (Formaldehyde)}$ = Single HAP (Formaldehyde) Emissions (tons/month)~~
~~ER_{19} = 0.920 lb/hr, emission rate for formaldehyde for turbines 19A, 19B, and 19C or value established in latest compliant stack test~~
~~ER_{U20} = 1.10 lb/hr, emission rate for formaldehyde for turbine Unit 20 or value established in latest compliant stack test~~
~~HR_{19A} = Number of operating hours per month for turbine 19A~~
~~HR_{19B} = Number of operating hours per month for turbine 19B~~
~~HR_{19C} = Number of operating hours per month for turbine 19C~~
~~HR_{U20} = Number of operating hours per month for turbine Unit 20~~
~~HI_{16A} = Heat input from turbine 16A (MMBtu/month)~~
~~HI_{16B} = Heat input from turbine 16B (MMBtu/month)~~

~~NT_{TB} = Natural gas throughput from temporary boiler (MMscf/month)~~
~~DT_{350FP} = Diesel fuel throughput from 350 diesel fire pump (hp-hr/month)~~
~~DT_{EDG1} = Diesel fuel throughput from emergency diesel generator EDG1 (hp-hr/month)~~
~~DT_{FP1} = Diesel fuel throughput from emergency diesel fire pump FP1 (hp-hr/month)~~
~~EF_{16} = 7.10E-04 lb/MMBtu, formaldehyde emission factor from AP-42 (Chapter 3.1 - Table 3.1-3)~~
~~EF_{TB} = 7.50E-02 lb/MMscf, formaldehyde emission factor from AP-42 (Chapter 1.4 - Table 1.4-3)~~
~~EF_{350FP} = 8.26E-06 lb/hp-hr, formaldehyde emission factor, calculated based on AP-42 (Chapter 3.3 - Table 3.3-2)*~~
~~EF_{EDG1} = 5.52E-07 lb/hp-hr, formaldehyde emission factor, calculated based on AP-42 (Chapter 3.4 - Table 3.4-3)*~~
~~EF_{FP1} = 8.26E-06 lb/hp-hr, formaldehyde emission factor, calculated based on AP-42 (Chapter 3.3 - Table 3.3-2)*~~
~~i = Each calendar month within the twelve (12) consecutive month period~~
~~* Emission Factors in lb/hp-hr were calculated as follows: EF (lb/MMBtu) x 7,000 (Btu/hp-hr) x (1 MMBtu / 1,000,000 Btu)~~

~~D.0.4 Testing Requirements [326 IAC 2-1.1-11]~~

~~In order to demonstrate compliance with Condition D.0.1 and to verify the emission rates for formaldehyde, not later than 180 days after the startup of the following emission units, the Permittee shall perform formaldehyde testing as follows:~~

~~Emission Unit~~	~~Emission Unit ID~~	~~Pollutant~~	~~Testing Frequency~~
~~One (1) of the three (3) aero-derivative combustion turbines~~	~~Units 19A, 19B, and 19C~~	~~Formaldehyde (0.920 lb/hr)~~	~~One time~~
~~Frame type combustion turbine~~	~~Unit 20~~	~~Formaldehyde (1.10 lb/hr)~~	~~One time~~

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

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

~~D.0.5 Record Keeping Requirement~~

~~(a) To document the compliance status with Conditions D.0.1, the Permittee shall maintain monthly records in accordance with (1) and (3) below. Records maintained for (1) and (3) shall be taken as stated below and shall be complete and sufficient to establish compliance with the combined HAPs and single HAP emission limits established in Conditions D.0.1:~~

~~(1) Monthly combined total HAP emissions as calculated using the equation in Condition D.0.2.~~

~~(2) Monthly combined single HAP (formaldehyde) emissions as calculated using the equation in Condition D.0.3.~~

~~(3) The dates of shutdown for each unit listed in Condition D.0.1(c).~~

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

~~D.0.6 Reporting Requirements~~

~~A quarterly summary of the information to document the compliance status with D.0.1 shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official," as defined by 326 IAC 2-7-1(35).~~

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SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

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D.3.2 ~~Reserved~~**PSD Minor Limits for PM, PM10, PM2.5, NOx, and Sulfuric Acid Mist (H2SO4)**

In order to render the requirements of 326 IAC 2-2 (Preventive of Significant Deterioration (PSD)) not applicable to the 2026 CCCT Project modification permitted under SSM No. 073-49556-00008, the Permittee shall comply with the following:

(a) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, the combined PM emissions from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 shall not exceed 91.0 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(b) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, the combined PM10 emissions from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 shall not exceed 345.0 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(c) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, the combined PM2.5 emissions from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 shall not exceed 292.0 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(d) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, the combined NOx emissions from Unit 17 and Unit 18 shall not exceed 1,560.0 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(e) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, the combined sulfuric acid mist (H2SO4) emissions from Unit 17 and Unit 18 shall not exceed 280.0 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

Compliance with these limits and Condition D.14.4, shall limit the potential to emit of PM, PM10, PM2.5, NOx, and H2SO4 to less than 25, 15, 10, 40, and 7 tons per twelve (12) consecutive month period, respectively, and shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2026 CCCT Project modification permitted under SSM No. 073-49556-00008 for these regulated NSR pollutants.

*****

D.3.5 ~~Reserved~~**Compliance Determination**

(a) Compliance with PM emissions limit from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 in Conditions D.3.2(a) shall be determined as follow:

$$\boldsymbol{PM} = \sum_{i=1}^{12} (\mathbf{EU17} + \mathbf{EU18} + \mathbf{ECU17} + \mathbf{ECU18})$$

where:

PM = Total PM emissions (tons/year) from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18
***i* = Each calendar month within the twelve (12) consecutive month period**
E_{U17} = PM emissions (tons/month) from Unit 17 calculated using the CEMS data.
E_{U18} = PM emission (tons/month) from Unit 18 calculated using the CEMS data.
E_{CU17} = PM emission (tons/month) from Colling Tower Unit 17 calculated using the following equation:

E_{CU17} = EF * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

E_{CU18} = PM emission (tons/month) from Colling Tower Unit 18 calculated using the following equation:

E_{CU17} = EF * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

(b) Compliance with PM10 emissions limit from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 in Conditions D.3.2(b) shall be determined as follow:

$$PM10 = \sum_{i=1}^{12} (\mathbf{EU17} + \mathbf{EU18} + \mathbf{ECU17} + \mathbf{ECU18})$$

where:

PM10 = Total PM10 emissions (tons/year) from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18
***i* = Each calendar month within the twelve (12) consecutive month period**
E_{U17} = PM10 emissions (tons/month) from Unit 17 calculated using the CEMS data.
E_{U18} = PM10 emission (tons/month) from Unit 18 calculated using the CEMS data.
E_{CU17} = PM10 emission (tons/month) from Colling Tower Unit 17 calculated using the following equation:

E_{CU17} = EF * 70% * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
70% = % PM to PM10 ratio according to California SCAQMD CEIDARS
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

E_{CU18} = PM emission (tons/month) from Colling Tower Unit 18 calculated using the following equation:

E_{CU17} = EF * 70% * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
70% = % PM to PM10 ratio according to California SCAQMD CEIDARS
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

(c) Compliance with PM2.5 emissions limit from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 in Conditions D.3.2(c) shall be determined as follow:

$$PM2.5 = \sum_{i=1}^{12} (\mathbf{EU17} + \mathbf{EU18} + \mathbf{ECU17} + \mathbf{ECU18})$$

where:

PM2.5 = Total PM2.5 emissions (tons/year) from Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18
***i* = Each calendar month within the twelve (12) consecutive month period**
E_{U17} = PM2.5 emissions (tons/month) from Unit 17 calculated using the CEMS data.
E_{U18} = PM2.5 emission (tons/month) from Unit 18 calculated using the CEMS data.
E_{CU17} = PM2.5 emission (tons/month) from Colling Tower Unit 17 calculated using the following equation:

E_{CU17} = EF * 40% * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
40% = % PM to PM2.5 ratio according to California SCAQMD CEIDARS
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

E_{CU18} = PM2.5 emission (tons/month) from Colling Tower Unit 18 calculated using the following equation:

E_{CU17} = EF * 40% * CR * 60 * H * TSD / 10^6

where:

EF = 1.7 lb/1000 gal, PM emission factor from AP-42, Table 13.4-1
40% = % PM to PM2.5 ratio according to California SCAQMD CEIDARS
CR = Recirculation Rate (gram per minutes)
H = hours of operations per month
TSD = Total dissolved solids (ppm)

(d) Compliance with combined NOx emissions limit from Unit 17 and Unit 18 in Condition D.3.2(d) shall be determined using the continuous emissions monitoring data.

(e) Compliance with combined sulfuric acid mist (H2SO4) emissions limit from Unit 17 and Unit 18 in Condition D.3.2(e) shall be determined by calculating H2SO4 emissions using the emissions calculations used to calculate H2SO4 releases for the Toxics Release Inventory (TRI) program.

*****

D.3.15 NOx Monitoring System Downtime

(a) In the event that a breakdown of a NOx continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a NOx continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup NOx CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary NOx CEMS, the Permittee shall comply with the following:

(1) In instances of CEMS downtime, the Permittee shall report the NOx mass emissions in accordance with the procedures regulated by 40 CFR Part 75, Appendix D (Optional SO2 Emissions Data Protocol) for fuel flow meters requirements, 40 CFR Part 75, Appendix E (Optional NOx Emissions Estimation Protocol) for emission rate curve establishment, and Appendix G (Determination of CO2 Emissions). NOx mass emissions reported shall be based on the fuel-and-unit specific NOx emission rates ("load curve") established during the latest and most representative CEMS data.

(c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during operations, with at least four (4) hours between each set of readings, until a NOx CEMS is online.

*****

D.3.16~~5~~ Record Keeping Requirements

*****

(g) On and after the date the first combustion turbine in the 2026 CCCT Project is started up, to document the compliance status with Condition D.3.2, the Permittee shall maintain monthly records in accordance with (1) through (5) below. Records maintained for (1) through (5) shall be taken as stated below and shall be complete and sufficient to establish compliance with the PM, PM10, PM2.5, NOx, and H2SO4 emission limits established in Condition D.13.2:

(1) Monthly PM emissions from the Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 as calculated in Condition D.3.5(a).

(2) Monthly PM10 emissions from the Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 as calculated in Condition D.3.5(b).

(3) Monthly PM2.5 emissions from the Unit 17, Unit 18, Cooling Tower for Unit 17, and Cooling Tower for Unit 18 as calculated in Condition D.3.5(c).

(4) Record the NOx output of the continuous monitoring system and perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7 for Unit 17 and Unit 18.

(5) Monthly H2SO4 emissions from Unit 17 and Unit 18 as calculated in Condition D.3.5(e).

(**h~~g~~**) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

*****

D.3.1**7~~6~~** Reporting Requirements

*****

(b) ~~Reserved~~ **A quarterly summary of the information to document the compliance status with Conditions D.3.2(a), D.3.2(b) and D.3.2(c) shall be submitted not later than thirty (30) days after the end of the quarter being reported. 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(33). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.**

*****

D.3.18 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) Pursuant 326 IAC 3-5-5(f)(1), the Permittee shall prepare and submit to IDEM, OAQ a written report for performance audits as follows:

(1) Owners or operators of emissions units required to conduct a:

(A) cylinder gas audit;
(B) relative accuracy test audit; or
(C) continuous opacity monitor calibration error audit;

on continuous emission monitors shall prepare a written report of the results of the performance audit for each calendar quarter, or for other periods required by the department. The owner or operator shall submit quarterly reports to the department within thirty (30) calendar days after the end of each quarter for cylinder gas audits and continuous opacity monitor calibration error audits and within forty-five (45) calendar days after the completion of the test for relative accuracy test audits.

(2) The report must contain the information required by 326 IAC 3-5-5(f)(2).

(b) Pursuant to 326 IAC 3-5-7(c)(4), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) date of downtime;
(2) time of commencement;
(3) duration of each downtime;
(4) reasons for each downtime; and
(5) nature of system repairs and adjustments.

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

*****

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

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Unit 17 and Unit 18, and their associated cooling towers
Parameter: Combined PM Emissions
Limit: Shall not exceed 91.0 tons 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
	Combined PM Emissions (tons)	*Combined PM Emissions (tons)*	*Combined PM Emissions (tons)*
	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 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Unit 17 and Unit 18, and their associated cooling towers
Parameter: Combined PM10 Emissions
Limit: Shall not exceed 345.0 tons 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
	Combined PM10 Emissions (tons)	*Combined PM10 Emissions (tons)*	*Combined PM10 Emissions (tons)*
	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 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Unit 17 and Unit 18, and their associated cooling towers
Parameter: Combined PM2.5 Emissions
Limit: Shall not exceed 292.0 tons 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
	Combined PM2.5 Emissions (tons)	*Combined PM2.5 Emissions (tons)*	*Combined PM2.5 Emissions (tons)*
	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: _____

*****

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a rated maximum heat input capacity of 519 MMBtu per hour, each using **oxidation catalyst as control and** CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR 60, Subpart KKKK these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa these units are intermediate load affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a rated maximum heat input capacity of 2,416 MMBtu per hour, using **oxidation catalyst as control and** CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR 60, Subpart KKKK this unit is an affected facility]
[Under 40 CFR 60, Subpart TTTTa this unit is an intermediate load affected facility]
[Under 40 CFR 63, Subpart YYYY, this unit 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.)

*****

D.13.2 Best Available Control Technology (BACT) - VOC [326 IAC 8-1-6]

*****

(b) The VOC emissions from the frame-type natural gas-fired combustion turbine (Unit 20) during ~~normal~~ **steady state** operation shall not exceed 6.50 pounds per hour.

*****

D.13.5 Compliance determination for PM and VOC

(a)

*****

ER_N = 4.90 lb/hr PM emission rate in ~~normal~~ **steady state** operation for Units 19A, 19B, and 19C or 11.6 lb/hour PM emission rate in ~~normal~~ **steady state**

*****

H = Number of hours of ~~normal~~ **steady state** operation for the month for Units 19A, 19B, 19C, and 20

*****

(b)

ER_N = 5.40 lb/hr, VOC emission rate in ~~normal~~ **steady state** operation for Units 19A, 19B, and 19C, or 6.50 lb/hr VOC emission rate in ~~normal~~ **steady state** operation for Unit 20, or value established in latest stack test.

*****

H = Number of hours of ~~normal~~ **steady state** operation for the month for Units 19A, 19B, 19C, and 20

*****

D.13.6 Startup & Shutdown Definition

For periods of startup and shutdown:

(1) Startup begins at the first firing of fuel in the stationary combustion turbine. For simple cycle turbines, startup ends when the stationary combustion turbine has reached steady state operation or after 1 hour, whichever is less.

(2) Shutdown is defined as the period of time the stationary combustion turbine exits steady state operating condition and ending with termination of combustion in the stationary combustion turbine.

*****

D.13.**7**~~6~~ NOx Continuous Emissions Monitoring (CEMS) Equipment Downtime

*****

D.13.**8**~~7~~ Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

*****

D.13.**9**~~8~~ Record Keeping Requirements

*****

(1) Monthly PM emissions from the combustion turbine Units 19A, 19B, 19C and 20 as calculated using the equation in Condition D.13.**5**~~6~~(a).

(2) Monthly VOC emissions from the combustion turbine Units 19A, 19B, 19C, and 20 as calculated using the equation in Condition D.13.**5**~~6~~(b).

D.13.**10**~~9~~ Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

*****

D.13.11~~0~~ Reporting Requirements

*****

SECTION D.14 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(o) Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a rated maximum nominal capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a rated maximum heat input of 987 MMBtu per hour, using dry low-NOx combustors and voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(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.14.1 PSD and VOC/BACT Emission Limitations (Steady State Operations) [326 IAC 2-2-3] [326 IAC 8-1-6]

Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the combustion turbines, identified as 21A, 21B, 22A, and 22B, as follows:

(a) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 1.00 ppmvd @ 15% O_2 on 3-hour average basis, excluding during periods of startup and shutdown for the combustion turbines for both simple cycle and combined cycle operations.

(b) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 2.00 ppmvd @15% O_2 on 3-hour average basis, excluding during periods of startup and shutdown when the combined cycle turbines are operated with duct burners.

(c) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 9.60 lb/hr on a 3-hour average basis, excluding during periods of startup and shutdown, when operating in combined cycle mode without duct burner.

(d) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 15.40 lb/hr on a 3-hour average basis, excluding during periods of startup and shutdown, when operating in combined cycle mode with duct burner.

(e) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 9.10 lb/hr on a 3-hour average basis, excluding during periods of startup and shutdown, when operating in simple cycle mode.

(f) VOC emissions from the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall be controlled using an oxidation catalyst and conducting good combustion practices.

D.14.2 PSD and VOC/BACT Emission Limitations (Startup, Shutdown and Malfunction) [326 IAC 2-2-3] [326 IAC 8-1-6]

The total VOC emissions from each combustion, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, turbine during any periods of startup and shutdown operation shall not exceed 25.6 tons per 12-month rolling total.

D.14.3 CO_2e PSD/BACT Emission Limitations [326 IAC 2-2-3]

Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the combustion turbines, identified as 21A, 21B, 22A, and 22B, as follows:

(a) CO_2 emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 1,170 lb/MW-hr (gross) per twelve (12) operating month period average when operating in simple cycle mode.

(b) CO_2 emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 800 lb/MW-hr (gross) per twelve (12) operating month period average when operating in combined cycle mode.

(c) CO_2e emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall be limited through the use of good combustion practices and energy efficient design.

(d) The total GHGs (CO2, CH4, and N2O) emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, when operating in simple cycle mode, including steady state operation and operation during any periods of startup and shutdown, shall not exceed 863,649 tons per twelve (12) consecutive month period with compliance determined at the end of each month (GWPs per 78 FR 71948).

(e) The total GHGs (CO2, CH4, and N2O) emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, when operating in combined cycle mode, including steady state operation and operation during any periods of startup and shutdown, shall not exceed 1,751,087 tons per twelve (12) consecutive month period with compliance determined at the end of each month (GWPs per 78 FR 71948).

D.14.4 PSD Minor Limits [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (Preventive of Significant Deterioration (PSD)) not applicable to the 2026 CCCT Project Modification permitted under SSM No. 073-49556-00008, the Permittee shall comply with the following:

(a) The combined PM emissions from the four (4) combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B shall not exceed 120.3 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

(b) The combined NOx emissions from the four (4) combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B shall not exceed 1,566.3 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month.

Compliance with these limits, shall limit the potential to emit of PM and NOx to less than 25 and 40 tons per twelve (12) consecutive month period, respectively, and shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2026 Modification permitted under SSM No. 073-49556-00008.

D.14.5 PSD Minor Limit [326 IAC 2-2]

(a) In order to render the requirements of 326 IAC 2-2 (Preventive of Significant Deterioration (PSD)) not applicable to the 2026 CCCT Project Modification permitted under SSM No. 073-49556-00008, the Permittee shall not begin operation of the final combustion turbine (Unit 21A, Unit 21B, Unit 22A, or Unit 22B and their

associated duct burners) under 2026 CCCT Project until after the contemporaneous period of 2024 Peaker project has ended (*i.e.* the final combustion turbine (Unit 19A, Unit 19B, Unit 19C, or Unit 20) is started up).

(b) On and after the date of startup, of the first CT under the 2026 CCCT project, Unit 17, Unit 18, Unit 17 cooling tower, and Unit 18 cooling tower must comply with the emission limtiations established in D.3.2.

Compliance with these conditions shall render the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) not applicable to the 2026 CCCT Project Modification permitted under SSM No. 073-49556-00008.

D.14.6 Particulate Emissions Limitations for Sources of Indirect Heating [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-1(f) (Particulate Emission Limitations for Sources of Indirect Heating), the particulate emissions from the heat recovery steam generator (HRSG) with duct burner shall be limited to 0.10 pound per MMBtu heat input.

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

D.14.7 VOC Control

In order to assure compliance with Conditions D.14.1, the oxidation catalysts for VOC control shall be in operation and control VOC emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, at all times these combustion turbines are in steady-state operation.

D.14.8 Testing Requirements [326 IAC 2-1.1-11]

In order to verify the emission rates for VOC and CO and demonstrate compliance with Conditions D.14.1(a) and D.14.1(b), not later than 180 days after the initial startup of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, the Permittee shall perform VOC and CO testing of the following combustion turbines utilizing methods as approved by the Commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be alternated between the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, such that testing shall not be repeated until each combustion turbine has been tested. 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.

Emission Unit	Control Device	Pollutant/ Parameter	Frequency of Testing
Combustion Turbines 21A, 21B, 22A, and 22B	Oxidation Catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B)	VOC (1.0 ppmvd @ 15% O_2)[1]	Every 5 years
		VOC (2.0 ppmvd @ 15% O_2)[2]	
		VOC (9.60 lb/hr)[1]	
		VOC (15.40 lb/hr)[2]	
		VOC (9.10 lb/hr)[3]	
		CO (16.80 lb/hr)[1]	Every 5 years
		CO (21.50 lb/hr)[2]	
		CO (15.90 lb/hr)[3]	

[1] When operating in combined cycle mode without duct burner
[2] When operating in combined cycle mode with duct burner
[3] When operating in simple cycle mode

D.14.9 Continuous Emissions Monitoring [326 IAC 3-5][326 IAC 2-7-6(1),(6)][40 CFR 60, Subpart KKKK]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous emission monitoring systems for the combustion turbines, identified as Unit 21A,

Unit 21B, Unit 22A, and Unit 22B, shall be calibrated, maintained, and operated for measuring NOx, which meet all applicable performance specifications of 326 IAC 3-5-2.

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

(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, 40 CFR 60, Subpart KKKK.

D.14.10 Startup & Shutdown Definition

For periods of startup and shutdown:

(1) Startup begins at the first firing of fuel in the stationary combustion turbine. For simple cycle turbines, startup ends when the stationary combustion turbine has reached steady state operation or after 1 hour, whichever is less. For combined cycle stationary combustion turbines, startup ends when the stationary combustion turbine has reached steady state operation or after 3 hours, whichever is less. Stationary combustion turbines in combined cycle configurations that are operating as simple cycle must meet the startup requirements for simple cycle stationary combustion turbines.

(2) Shutdown is defined as the period of time the stationary combustion turbine exits steady state operating condition and ending with termination of combustion in the stationary combustion turbine.

D.14.11 Compliance Determination

(a) To determine the compliance status with Condition D.14.2, the following equation shall be used to determine total VOC emissions from each combustion turbine (Unit 21A, Unit 21B, Unit 22A, and Unit 22B) during any periods of startup and shutdown operation:

$$E_{VOC} = \sum_{i=1}^{12} \left(\frac{[(ER_{S(SU/SD)} * Evt_S)]}{2000} + \frac{[(ER_{C(SU/SD)} * Evt_C)]}{2000} \right)$$

Where:

E_{VOC} = Total VOC emissions (tons/year) form the combustion turbine
$ER_{S(SU/SD)}$ = 140 lb/event, VOC emission rate during startup/shutdown events in simple cycle for the combustion turbine
$ER_{C(SU/SD)}$ = 140 lb/event, VOC emission rate during startup/shutdown events in combined cycle operation for the combustion turbine
Evt_S = Number of events per month during simple cycle operation for the combustion turbine, where one event is a startup and shutdown cycle
Evt_C = Number of events per month during combined cycle operation for the combustion turbine, where one event is a startup and shutdown cycle
i = Each calendar month within the twelve (12) consecutive month period

(b) To determine the compliance status with Condition D.14.3(d), the following equation shall be used to determine GHGs emissions from each combustion turbine (Unit 21A, Unit 21B, Unit 22A, and Unit 22B) when operating in simple cycle mode shall be determined using the following equation:

$$E_{GHGs} = \sum_{i=1}^{12} \left(\frac{[(ER_S * H_S) + (ER_{S(SU/SD)} * Evt_S)]}{2000} \right)$$

Where:

E_{GHGs} = Total GHGs emissions (tons/year) form each combustion turbine
ER_S = 446,445 lb/hr, GHGs emission rate during simple cycle steady state operation for the combustion turbine, or value established in latest stack test
$ER_{S(SU/SD)}$ = 446,445 lb/event, GHGs emission rate during startup/shutdown events in simple cycle for the combustion turbine
Evt_S = Number of events per month during simple cycle operation for the combustion turbine, where one event is a startup and shutdown cycle
H_S = Number of hours during simple cycle operation per month for the combustion turbine
i = Each calendar month within the twelve (12) consecutive month period

(c) To determine the compliance status with Condition D.14.3(e), the following equation shall be used to determine GHGs emissions from each combustion turbine (Unit 21A, Unit 21B, Unit 22A, and Unit 22B) when operating in combined cycle mode shall be determined using the following equation:

$$E_{GHGs} = \sum_{i=1}^{12} \left(\frac{[(ER_C * H_C) + (ER_{CDB} * H_{CDB}) + (ER_{C(SU/SD)} * Evt_C)]}{2000} \right)$$

Where:

E_{GHGs} = Total GHGs emissions (tons/year) form each combustion turbine
ER_C = 473,770 lb/hr, GHGs emission rate during combined cycle steady state operation without duct burner for the combustion turbine, or value established in latest stack test
ER_{CDB} = 601,899 lb/hr, GHGs emission rate during combined cycle steady state operation with duct burner for the combustion turbine, or value established in latest stack test
$ER_{C(SU/SD)}$ = 473,770 lb/event, GHGs emission rate during startup/shutdown events in combined cycle operation for the combustion turbine
Evt_C = Number of events per month during combined cycle operation for the combustion turbine, where one event is a startup and shutdown cycle
H_C = Number of hours during combined cycle operation without duct burner per month for the combustion turbine
H_{CDB} = Number of hours during combined cycle operation with duct burner per month for the combustion turbine
i = Each calendar month within the twelve (12) consecutive month period

(d) To determine the compliance status with Condition D.14.4(a), the following equation shall be used to determine combined PM emissions from the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B:

$$E_{PM} = \sum_{i=1}^{12} \left(\sum_{n} \frac{[(ER_S * H_S) + (ER_{S(SU/SD)} * Evt_S)]}{2000} + \sum_{n} \frac{[(ER_C * H_C) + (ER_{CDB} * H_{CDB}) + (ER_{C(SU/SD)} * Evt_C)]}{2000} \right)$$

Where:

E_{PM} = Total PM emissions (tons/year) form the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B

ER_S = 8.05 lb/hr, PM emission rate during simple cycle steady state operation for the combustion turbines 21A, 21B, 22A, and 22B or value established in latest stack test

ER_C = 6.60 lb/hr, PM emission rate during combined cycle steady state operation without duct burner for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B or value established in latest stack test

ER_{CDB} = 12.30 lb/hr, PM emission rate during combined cycle steady state operation with duct burner for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B or value established in latest stack test

$ER_{S(SU/SD)}$ = 8.55 lb/event, PM emission rate during startup/shutdown events in simple cycle for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B

$ER_{C(SU/SD)}$ = 17.10 lb/event, PM emission rate during startup/shutdown events in combined cycle operation for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B

Evt_S = Number of events per month during simple cycle operation for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B , where one event is a startup and shutdown cycle

Evt_C = Number of events per month during combined cycle operation for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B , where one event is a startup and shutdown cycle

H_S = Number of hours during simple cycle operation per month for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B

H_C = Number of hours during combined cycle operation without duct burner per month for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B

H_{CDB} = Number of hours during combined cycle operation with duct burner per month for the combustion turbines Unit 21A, Unit 21B, Unit 22A, and Unit 22B

i = Each calendar month within the twelve (12) consecutive month period

n = Each combustion turbine Unit 21A, Unit 21B, Unit 22A, and Unit 22B

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

D.14.12 Oxidation Catalyst Parametric Monitoring [40 CFR 64]

(a) In order to assure compliance with Conditions D.14.1, a continuous monitoring system shall be calibrated, maintained, and operated on each oxidation catalyst for measuring operating temperature. For the purpose of this condition, continuous means no less often than once per fifteen (15) minutes excluding periods of startup and shutdown. The output of this system shall be recorded as 4-hour average. From the date of startup until the stack test results are available, the Permittee shall operate the oxidation catalyst at or above the 4-hour average temperature of 500°F.

(b) The Permittee shall determine the 4-hour average temperature from the latest valid stack test that demonstrates compliance with limits in Conditions D.14.1.

(c) On and after the date the stack test results are available, the Permittee shall operate the oxidation catalyst at or above the 4-hour average temperature as observed during the latest compliant stack test.

(d) If the 4-hour average temperature falls below the above mentioned 4-hour average temperature, 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 4-hour average temperature reading below the above mentioned 4-hour average temperature is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

(e) Annual sampling and analysis of the catalyst activity (i.e., conversion efficiency) following the manufacturer's or catalyst supplier's recommended procedures. If problems are found during the catalyst activity test, the Permittee must replace the catalyst bed or take other corrective action consistent with the manufacturer's recommendations.

(1) Determine the catalyst activity level by evaluating the conversion efficiency.

(2) The catalyst conversion efficiency is evaluated and compared to typical values for fresh catalyst.

(3) An excursion is identified as a finding that the conversion efficiency is beyond the operational range of the catalyst as defined by the manufacturer.

D.14.13 NOx Continuous Emissions Monitoring (CEMS) Equipment Downtime [326 IAC 3-5-6]

(a) In the event that a breakdown of a NOx continuous emissions monitoring system (CEMS) occurs, a record shall be made of the time and reason of the breakdown and efforts made to correct the problem.

(b) Whenever a NOx continuous emissions monitoring system (CEMS) is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup NOx CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary NOx CEMS, the Permittee shall comply with the following:

(1) In instances of CEMS downtime, the Permittee shall report the NOx mass emissions in accordance with the procedures regulated by 40 CFR Part 75, Appendix D (Optional SO2 Emissions Data Protocol) for fuel flow meters requirements, 40 CFR Part 75, Appendix E (Optional NOx Emissions Estimation Protocol) for emission rate curve establishment, and Appendix G (Determination of CO2 Emissions). NOx mass emissions reported shall be based on the fuel-and-unit specific NOx emission rates ("load curve") established during the latest and most representative CEMS data.

(c) Parametric monitoring shall begin not more than twenty-four (24) hours after the start of the malfunction or down time at least twice per day during operations, with at least four (4) hours between each set of readings, until a NOx CEMS is online.

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

D.14.14 Record Keeping Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) The Permittee shall record the output of the continuous monitoring systems (lb/hr) and shall perform the required record keeping pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(b) In the event that a breakdown of the NOx continuous emission monitoring systems (CEMS) occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

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

D.14.15 Record Keeping Requirements

(a) To document the compliance status with Conditions D.14.2, D.14.3 and D.14.4, the Permittee shall maintain monthly records in accordance with (1) and (4) below. Records maintained for (1) and (4) shall be taken as stated below and shall be complete and sufficient to establish compliance with the GHG, VOC, PM and NOx emission limits established in Conditions D.14.2, D.14.3 and D.14.4:

(1) To document the compliance status with Condition D.14.2(a), the Permittee shall maintain monthly records of the CO2e emissions.

(2) To document the compliance status with Condition D.14.2(b), the Permittee shall maintain monthly records of the CO2e emissions.

(3) To document the compliance status with Condition D.14.4(b), the Permittee shall maintain monthly records of the NOx emissions.

(4) Monthly VOC emissions from each combustion turbine (Unit 21A, Unit 21B, Unit 22A, and Unit 22B) as calculated using the equation in Condition D.14.11(a).

(5) Monthly total GHGs emissions from each combustion turbine (Unit 21A, Unit 21B, Unit 22A, and Unit 22B) when operating in simple cycle mode as calculated using the equation in Condition D.14.11(b).

(6) Monthly total GHGs emissions from each combustion turbine (Unit 21A, Unit 21B, Unit 22A, and Unit 22B) when operating in combined cycle mode as calculated using the equation in Condition D.14.11(c).

(7) Monthly PM emissions from the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, as calculated using the equation in Condition D.14.11(d).

(b) The number of startup and shutdown events per month.

(c) The number of minutes for each startup event and each shutdown event.

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

D.14.16 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

(a) Pursuant to 326 IAC 3-5-5(f)(1), the Permittee shall prepare and submit to IDEM, OAQ a written report for performance audits as follows:

(1) Owners or operators of emissions units required to conduct a:

(A) cylinder gas audit;
(B) relative accuracy test audit; or
(C) continuous opacity monitor calibration error audit;

on continuous emission monitors shall prepare a written report of the results of the performance audit for each calendar quarter, or for other periods required by the department. The owner or operator shall submit quarterly reports to the department within thirty (30) calendar days after the end of each quarter for cylinder gas audits and continuous opacity monitor calibration error audits and within forty-five (45) calendar days after the completion of the test for relative accuracy test audits.

(2) The report must contain the information required by 326 IAC 3-5-5(f)(2).

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(33).

(b) Pursuant to 326 IAC 3-5-7(c)(4), reporting of continuous monitoring system instrument downtime, except for zero (0) and span checks, which shall be reported separately, shall include the following:

(1) date of downtime;
(2) time of commencement;
(3) duration of each downtime;
(4) reasons for each downtime; and
(5) nature of system repairs and adjustments.

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(33).

D.14.17 Reporting Requirements

A quarterly summary of the information to document the compliance status with Conditions D.14.2, D.14.3(d), D14.3(e), D.14.4(a) and D.14.4(b) shall be submitted not later than thirty (30) days after the end of the quarter being reported. 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(33). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

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SECTION D.15 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(p) Two (2) natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, approved in 2026 for construction, each with a rated maximum capacity of 115 MMBtu per hour, using low NOx burners, and exhausting to stacks SAUX1 and SAUX2.

[Under 40 CFR 60, Subpart Db, these units are affected facilities]
[Under 40 CFR 63, Subpart DDDDD, these units are affected sources]

(q) One (1) natural gas-fired dew point heater, identified as DPH1, approved in 2026 for construction, with a rated maximum capacity of 28 MMBtu per hour and exhausting to stack SDPH1.

[Under 40 CFR 60, Subpart Dc, this unit is an affected facility]
[Under 40 CFR 63, Subpart DDDDD, this unit is an affected source]

(r) Two (2) 2,500 kW diesel-fired certified emergency generators, identified as EDGCC1 and EDGCC2, approved in 2026 for construction, each with a rated maximum capacity of 3,353 hp, and exhausting to stacks SEDGCC1 and SEDGCC2.

[Under 40 CFR 60, Subpart IIII, these units are affected facilities]
[Under 40 CFR 63, Subpart ZZZZ, these units are affected sources]

(s) Two (2) 244 kW diesel-fired certified emergency fire pumps, identified as FPCC1 and FPCC2, approved in 2026 for construction, each with a rated maximum capacity of 327 hp, and exhausting to stacks SFPCC1 and SFPCC2.

[Under 40 CFR 60, Subpart IIII, these units are affected facilities]
[Under 40 CFR 63, Subpart ZZZZ, these units are affected sources]

Insignificant Activities:

(j) Two (2) mechanical draft cooling towers, identified as CTH1 and CTH2, approved in 2026 for construction, each with a rated maximum circulation of 280,000 gallons of water per minute, TDS of 2,000 ppm, and total drift loss of 0.0005%.

(k) One (1) diesel storage tank, identified as TKCC1, approved in 2026 for construction, with a design storage capacity of 5,000 gallons and rated throughput of 130,000 gallons per year, and exhausting outdoors.

(l) Six (6) lube oil demister vents, identified as LOV21A, LOV21B, LOV22A, LOV22B, LOV21S, and LOV22S, approved in 2026 for construction, each with a vent flow rate of 500 cfm.

(m) High Voltage Electric Switchgear Containing Sulfur Hexafluoride (SF6), identified as CCCT - Circuit Breakers, approved in 2026 for construction.

(o) Natural gas piping components, identified as CCCT - Piping Systems, approved in 2026 for construction, including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections.

(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.15.1 VOC PSD Emission Limitations [326 IAC 2-2-3] [326 IAC 8-1-6]

(a) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the auxiliary boilers, identified as AUX1 and AUX2, as follows:

(1) VOC emissions from each auxiliary boiler AUX1 and AUX2 shall not exceed 5.5 lb/MMcf.

(2) VOC emissions from the auxiliary boilers, identified as AUX1 and AUX2, shall be controlled through the use of good combustion practices.

(b) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the emergency generators, identified as EDGCC1 and EDGCC2, as follows:

(1) VOC emissions from each emergency generators (EDGCC1 and EDGCC2) shall be controlled good combustion practices including the installation of an equipment design standard and compliance with the requirements of 40 CFR 60, Subpart IIII.

(c) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the emergency fire pump (FPCC1 and FPCC2), as follows:

(1) VOC emissions from each emergency fire pump (FPCC1 and FPCC2) shall be controlled good combustion practices including the installation of an equipment design standard and compliance with the requirements of 40 CFR 60, Subpart IIII.

(d) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the dew point heater DPH1, as follows:

(1) VOC emissions from the natural gas-fired dew point heater DPH1 shall not exceed 5.5 lb/MMcf.

(2) VOC emissions from the natural gas fired dew point heater DPH1 shall be controlled by good combustion practices.

(3) The Permittee shall only combust natural gas fuel in the dew point heater DPH1

(e) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the lube oil demister vents, identified as LOV21A, LOV21B, LOV22A, LOV22B, LOV21S, and LOV22S, as follows:

(1) VOC emissions from each of the lube oil demister vents shall be controlled through the use of demisters and good engineering design and operating practices.

(f) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the CCCT - natural gas piping system, as follows:

(1) The permittee shall implement an auditory/visual/olfactory (AVO) monitoring program for detecting leaks from the natural gas piping components installed as part of 2026 CCCT Project.

(2) AVO monitoring shall be performed in accordance with a written monitoring program.

(g) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the diesel storage tank (TKCC1), as follows:

(1) The permittee shall implement good equipment design and operating practices for the proposed diesel storage tank.

D.15.2 CO_2e PSD Emission Limitations [326 IAC 2-2-3]

(a) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the auxiliary boilers, identified as AUX1 and AUX2, as follows:

(1) CO_2e emissions from each of the auxiliary boilers AUX1 and AUX2 shall not exceed 119,438 lb/MMcf (GWPs per July 29, 2025).

(2) CO_2e emissions from each of the auxiliary boilers AUX1 and AUX2 shall be controlled through the use of natural gas fuel, implement efficient boiler design, and good combustion practices.

(b) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the emergency generators (EDGCC1 and EDGCC2), as follows:

(1) The CO_2e emissions from each emergency generator (EDGCC1 and EDGCC2) shall be controlled through the use of good combustion practices including the installation of an equipment design standard and the compliance of the 40 CFR Part 60 Subpart IIII.

(2) The CO_2e emissions from each emergency generator (EDGCC1 and EDGCC2) shall not exceed 163.6 lb/MMBtu (GWPs per July 29, 2025).

(c) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the emergency fire pump (FPCC1 and FPCC2), as follows:

(1) The CO_2e emissions from each emergency fire pump (FPCC1 and FPCC2) shall be controlled through the use of good combustion practices including the installation of an equipment design standard and the compliance of the 40 CFR Part 60 Subpart IIII.

(2) The CO_2e emissions from each emergency fire pump (FPCC1 and FPCC2) shall not exceed 163.6 lb/MMBtu (GWPs per July 29, 2025).

(d) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the dew point heater DPH1, as follows:

(1) CO_2e emissions from the natural gas fired dew point heater DPH1 shall not exceed 119,438 lb/MMcf (GWPs per July 29, 2025).

(2) GHG emissions from the natural gas fired dew point heater DPH1 shall be controlled by good combustion practices.

(3) The Permittee shall only combust natural gas fuel in the dew point heater DPH1.

(e) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the CCCT - Circuit Breakers, as follows:

(1) The Permittee shall use a fully enclosed pressurized SF6 circuit breakers outfitted with density alarms for leak detection

(2) The circuit breakers shall be designed to have a maximum SF6 leak rate not to exceed 0.5% per twelve (12) consecutive month period.

(f) Pursuant to PSD/SSM 073-49556-00008 and 326 IAC 2-2-3 (PSD), the "Best Available Control Technology" (BACT) emission controls shall be used for the CCCT - natural gas piping system, as follows:

(1) The permittee shall implement an auditory/visual/olfactory (AVO) monitoring program for detecting leaks from the natural gas piping components installed as part of 2026 CCCT Project.

(2) AVO monitoring shall be performed in accordance with a written monitoring program.

D.15.3 Particulate Emissions Limitations for Sources of Indirect Heating [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-1(f) (Particulate Emission Limitations for Sources of Indirect Heating), the particulate emissions from the auxiliary boilers (AUX1 and AUX2) and the dew point heater (DPH1) shall be limited to 0.10 pound per MMBtu heat input, each.

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SECTION E.1 TITLE IV CONDITIONS

ORIS Code: 6085

Emissions Unit Description:

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(**d**) **Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a rated maximum heat input capacity of 519 MMBtu per hour, each using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.**

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are intermediate load affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a rated maximum heat input capacity of 2,416 MMBtu per hour, using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR 60, Subpart KKKK, this unit is an affected facility]
[Under 40 CFR 60, Subpart TTTTa, this unit is an intermediate load affected facility]
[Under 40 CFR 63, Subpart YYYY, this unit is an affected source]

(o) Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a rated maximum capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a rated maximum heat input of 987 MMBtu per hour, using dry low-NOx combustors and voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

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

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SECTION E.6 NSPS

Emissions Unit Description:

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(r) Two (2) 2,500 kW diesel-fired certified emergency generators, identified as EDGCC1 and EDGCC2, approved in 2026 for construction, each with a rated maximum capacity of 3,353 hp, and exhausting indoors.

Under 40 CFR 60, Subpart IIII, the emergency generators EDGCC1 and EDGCC2 are considered emergency stationary compression ignition (CI) internal combustion engines (ICE) that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and with a displacement of less than 30 liters per cylinder.

Under 40 CFR 63, Subpart ZZZZ, the emergency generators EDGCC1 and EDGCC2 are considered new emergency stationary compression ignition (CI) reciprocating internal combustion engines (RICE) that commenced construction on or after December 19, 2002, located at a major source of HAP emissions.

(s) Two (2) 244 kW diesel-fired certified emergency fire pumps, identified as FPCC1 and FPCC2, approved in 2026 for construction, each with a rated maximum capacity of 327 hp, and exhausting indoors.

Under 40 CFR 60, Subpart IIII, the emergency fire pumps FPCC1 and FPCC2 are considered emergency stationary compression ignition (CI) internal combustion engines (ICE) that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and with a displacement of less than 30 liters per cylinder.

Under 40 CFR 63, Subpart ZZZZ, the emergency fire pumps FPCC1 and FPCC2 are considered new emergency stationary compression ignition (CI) reciprocating internal combustion engines (RICE) that commenced construction on or after December 19, 2002, located at a major source of HAP emissions.

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

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E.6.2 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines NSPS [326 IAC 12] [40 CFR Part 60, Subpart IIII]

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(c) Two (2) diesel-fired emergency generators EDGCC1 and EDGCC2

60.4200(a)(2)(i)	**Am I subject to this subpart?**
60.4204(b)	**What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?**
60.4205(b)	**What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?**

60.4206	**How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?**
60.4207(b)	**What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?**
60.4208	**What is the deadline for importing or installing stationary CI ICE produced in previous model years?**
60.4209	**What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?**
60.4211(a), (c), (f) and (g)(3)	**What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?**
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?**
60.4214(b), (d), (g), (h), (i) and (j)	**What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?**
60.4218	**What General Provisions and confidential information provisions apply to me?**
60.4219	**What definitions apply to this subpart?**
Tables to Subpart IIII of Part 60	
Table 8	**Applicability of General Provisions to Subpart IIII**

(d) Two (2) diesel-fired emergency fire pumps FPCC1 and FPCC2

60.4200(a)(2)(ii)	**Am I subject to this subpart?**
60.4204(b)	**What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?**
60.4205(c)	**What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?**
60.4206	**How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?**
60.4207(b)	**What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?**
60.4208	**What is the deadline for importing or installing stationary CI ICE produced in previous model years?**
60.4209	**What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?**
60.4211(a), (c), (f) and (g)(2)	**What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?**
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?**
60.4214(b), (d), (g), (h), (i) and (j)	**What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?**
60.4218	**What General Provisions and confidential information provisions apply to me?**
60.4219	**What definitions apply to this subpart?**
Tables to Subpart IIII of Part 60	
Table 8	**Applicability of General Provisions to Subpart IIII**

*****

Emissions Unit Description:

*****

(r) Two (2) 2,500 kW diesel-fired certified emergency generators, identified as EDGCC1 and EDGCC2, approved in 2026 for construction, each with a rated maximum capacity of 3,353 hp, and exhausting indoors.

Under 40 CFR 60, Subpart IIII, the emergency generators EDGCC1 and EDGCC2 are considered emergency stationary compression ignition (CI) internal combustion engines (ICE) that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and with a displacement of less than 30 liters per cylinder.

Under 40 CFR 63, Subpart ZZZZ, the emergency generators EDGCC1 and EDGCC2 are considered new emergency stationary compression ignition (CI) reciprocating internal combustion engines (RICE) that commenced construction on or after December 19, 2002, located at a major source of HAP emissions.

(s) Two (2) 244 kW diesel-fired certified emergency fire pumps, identified as FPCC1 and FPCC2, approved in 2026 for construction, each with a rated maximum capacity of 327 hp, and exhausting indoors.

Under 40 CFR 60, Subpart IIII, the emergency fire pumps FPCC1 and FPCC2 are considered emergency stationary compression ignition (CI) internal combustion engines (ICE) that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and with a displacement of less than 30 liters per cylinder.

Under 40 CFR 63, Subpart ZZZZ, the emergency fire pumps FPCC1 and FPCC2 are considered new emergency stationary compression ignition (CI) reciprocating internal combustion engines (RICE) that commenced construction on or after December 19, 2002, located at a major source of HAP emissions.

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

*****

E.9.2 Stationary Reciprocating Internal Combustion Engines NESHAP [40 CFR Part 63, Subpart ZZZZ] [326 IAC 20-82]

*****

(b) One (1) diesel emergency generator (EDG1) and **two (2) diesel-fired emergency generators (EDGCC1 and EDGCC2)** ~~one (1) diesel emergency fire pump (FP1)~~

63.6580	**What is the purpose of subpart ZZZZ?**
63.6585(b)	**Am I subject to this subpart?**
63.6590(a)(2)(i) and (b)(1)(i)	**What parts of my plant does this subpart cover?**

~~(1) 40 CFR 63.6580~~
~~(2) 40 CFR 63.6585~~
~~(3) 40 CFR 63.6590(a)(2)(ii) and (c)(7)~~

(c) One (1) diesel emergency fire pump (FP1) and two (2) diesel-fired emergency fire pumps (FPCC1 and FPCC2)

63.6580	**What is the purpose of subpart ZZZZ?**
63.6585(b)	**Am I subject to this subpart?**

63.6590(a)(2)(i) and (c)(7)	**What parts of my plant does this subpart cover?**

*****

SECTION E.10 NSPS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a rated maximum heat input capacity of 519 MMBtu per hour, each using **oxidation catalyst as control and** CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are intermediate load affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a rated maximum heat input capacity of 2,416 MMBtu per hour, using **oxidation catalyst as control and** CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR 60, Subpart KKKK, this unit is an affected facility]
[Under 40 CFR 60, Subpart TTTTa, this unit is an intermediate load affected facility]
[Under 40 CFR 63, Subpart YYYY, this unit is an affected source]

(o) Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a rated maximum capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a rated maximum heat input of 987 MMBtu per hour, using dry low-NOx combustors and voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

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

*****

E.10.2 New Source Performance Standards for **Stationary Combustion Turbines that Commenced Construction, Modification or Reconstruction After February 18, 2005, and on or Before December 13, 2024** ~~Stationary Combustion Turbines Requirements~~ NSPS [326 IAC 12] [40 CFR Part 60, Subpart KKKK]

*****

60.4305	**Does this subpart apply to my stationary combustion turbine?**
60.4315	**What pollutants are regulated by this subpart?**
60.4320(a)	**What emission limits must I meet for nitrogen oxides (NOX)?**
60.4330(a)	**What emission limits must I meet for sulfur dioxide (SO2?**
60.4333	**What are my general requirements for complying with this subpart?**
60.4340	**How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?**
60.4345	**What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?**
60.4350	**How do I use data from the continuous emission monitoring equipment to identify excess emissions?**
60.4355	**How do I establish and document a proper parameter monitoring plan?**
60.4365	**How can I be exempted from monitoring the total sulfur content of the fuel?**
60.4370(b)	**How often must I determine the sulfur content of the fuel?**
60.4375	**What reports must I submit?**
60.4380	**How are excess emissions and monitor downtime defined for NOX?**
60.4395	**When must I submit my reports?**
60.4400	**How do I conduct the initial and subsequent performance tests, regarding NOX?**
60.4405	**How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS?**
60.4410	**How do I establish a valid parameter range if I have chosen to continuously monitor parameters?**
60.4420	**What definitions apply to this subpart?**
Tables to Subpart KKKK of Part 60	
Table 1	**Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines**

~~(1) 40 CFR 60.4305~~
~~(2) 40 CFR 60.4315~~
~~(3) 40 CFR 60.4320(a)~~
~~(4) 40 CFR 60.4330(a)~~
~~(5) 40 CFR 60.4333~~
~~(6) 40 CFR 60.4340~~
~~(7) 40 CFR 60.4345~~
~~(8) 40 CFR 60.4350~~
~~(9) 40 CFR 60.4355~~
~~(10) 40 CFR 60.4365~~
~~(11) 40 CFR 60.4370(b)~~
~~(12) 40 CFR 60.4375~~
~~(13) 40 CFR 60.4380~~
~~(14) 40 CFR 60.4395~~
~~(15) 40 CFR 60.4400~~
~~(16) 40 CFR 60.4405~~
~~(17) 40 CFR 60.4410~~
~~(18) 40 CFR 60.4420~~
~~(19) Table 1 to Subpart KKKK of Part 60~~

*****

SECTION E.11 NSPS

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a rated maximum heat input capacity of 519 MMBtu per hour, each using **oxidation catalyst as control and** CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 Part 60, Subpart KKKK, these units are affected facilities]
[Under 40 Part 60, Subpart TTTTa, these units are intermediate load affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a rated maximum heat input capacity of 2,416 MMBtu per hour, using **oxidation catalyst as control and** CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR 60, Subpart KKKK, this unit is an affected facility]
[Under 40 CFR 60, Subpart TTTTa this unit is an intermediate load affected facility]
[Under 40 CFR 63, Subpart YYYY, this unit is an affected source]

(o) Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a rated maximum capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a rated maximum heat input of 987 MMBtu per hour, using dry low-NOx combustors and voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

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

*****

E.11.2 New Source Performance Standards for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary

Combustion Turbine Electric Generating Units Requirements NSPS [326 IAC 12] [40 CFR Part 60, Subpart TTTTa]

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

60.5509a(a)	**Am I subject to this subpart?**
60.5515a	**Which pollutants are regulated by this subpart?**
60.5520a	**What CO_2 emissions standard must I meet?**
60.5525a	**What are my general requirements for complying with this subpart?**
60.5535a	**How do I monitor and collect data to demonstrate compliance?**
60.5550a	**What notifications must I submit and when?**
60.5555a	**What reports must I submit and when?**
60.5560a	**What records must I maintain?**
60.5565a	**In what form and how long must I keep my records?**
60.5570a	**What parts of the general provisions apply to my affected EGU?**
60.5575a	**Who implements and enforces this subpart?**
60.5580a	**What definitions apply to this subpart?**
Tables to Subpart TTTTa of Part 60	
Table 1	**CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After May 23, 2023 (Gross or Net Energy Output-Based Standards Applicable as Approved by the Administrator)**
Table 3	**Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTTa**

~~(1) 40 CFR 60.5509a(a)~~
~~(2) 40 CFR 60.5515a~~
~~(3) 40 CFR 60.5520a~~
~~(4) 40 CFR 60.5525a~~
~~(5) 40 CFR 60.5535a~~
~~(6) 40 CFR 60.5550a~~
~~(7) 40 CFR 60.5555a~~
~~(8) 40 CFR 60.5560a~~
~~(9) 40 CFR 60.5565a~~
~~(10) 40 CFR 60.5580a~~
~~(11) Table 1 to Subpart TTTTa of Part 60~~
~~(12) Table 3 to Subpart TTTTa of Part 60~~

*****

SECTION E.12 NSPS

Emissions Unit Description:

(p) Two (2) natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, approved in 2026 for construction, each with a rated maximum capacity of 115 MMBtu per hour, using low NOx burners, and exhausting to stacks SAUX1 and SAUX2.

[Under 40 CFR 60, Subpart Db, these units are affected facilities]
[Under 40 CFR 63, Subpart DDDDD, these units are affected sources]

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

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

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

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

E.12.2 New Source Performance Standards for Industrial Commercial Institutional Steam Generating Units NSPS [326 IAC 12] [40 CFR Part 60, Subpart Db]

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

60.40b(a)	**Applicability and delegation of authority.**
60.41b	**Definitions.**
60.42b(k)(2)	**Standard for sulfur dioxide (SO2).**
60.44b(l)(1)	**Standard for nitrogen oxides (NOx).**
60.46b(e)(1)-(4)	**Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.**
60.48b(b), (c), (e), (f) and (g)	**Emission monitoring for particulate matter and nitrogen oxides.**
60.49b(a)-(c), (d), (g), (h), (i), (o), (r)(1), (v) and (w)	**Reporting and recordkeeping requirements.**

*****

SECTION E.13 NSPS

Emissions Unit Description:

(q) One (1) natural gas-fired dew point heater, identified as DPH1, approved in 2026 for construction, with a rated maximum capacity of 28 MMBtu per hour, and exhausting to stack SDPH1.

[Under 40 CFR 60, Subpart Dc, this unit is an affected facility]
[Under 40 CFR 63, Subpart DDDDD, this unit 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.13.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

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

(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
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

E.13.2 New Source Performance Standards for Small Industrial Commercial Institutional Steam Generating Units NSPS [326 IAC 12] [40 CFR Part 60, Subpart Dc]

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

60.40c	**Applicability and delegation of authority.**
60.41c	**Definitions.**
60.48c(a)	**Reporting and recordkeeping requirements.**

*****

SECTION E.14 NESHAP

Emissions Unit Description:

(p) Two (2) natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, approved in 2026 for construction, each with a rated maximum capacity of 115 MMBtu per hour, using low NOx burners, and exhausting to stacks SAUX1 and SAUX2.

[Under 40 CFR 60, Subpart Db, these units are affected facilities]
[Under 40 CFR 63, Subpart DDDDD, these units are affected sources]

(q) One (1) natural gas-fired dew point heater, identified as DPH1, approved in 2026 for construction, with a rated maximum capacity of 28 MMBtu per hour, and exhausting to stack SDPH1.

[Under 40 CFR 60, Subpart Dc, this is unit an affected facility]
[Under 40 CFR 63, Subpart DDDDD, this unit 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.14.1 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1] [40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-95, for the emission unit(s) 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
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

E.14.2 Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP [40 CFR Part 63, Subpart DDDDD] [326 IAC 20-95]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart DDDDD (included as Attachment N to the operating permit), which are incorporated by reference as 326 IAC 20-95, for the emission unit(s) listed above:

63.7480	What is the purpose of this subpart?
63.7485	Am I subject to this subpart?
63.7490(a)(2) and (b)	What is the affected source of this subpart?
63.7495(a)	When do I have to comply with this subpart?
63.7499(l)	What are the subcategories of boilers and process heaters?
63.7500	What emission limitations, work practice standards, and operating limits must I meet?
63.7505(a)	What are my general requirements for complying with this subpart?
63.7510	What are my initial compliance requirements and by what date must I conduct them?
63.7515	When must I conduct subsequent performance tests, fuel analyses, or tune-ups?
63.7545	What notifications must I submit and when?
63.7550	What reports must I submit and when?
63.7555	What records must I keep?
63.7560	In what form and how long must I keep my records?
63.7565	What parts of the General Provisions apply to me?
63.7570	Who implements and enforces this subpart?
63.7575	What definitions apply to this subpart?
Tables to Subpart DDDDD of Part 63	
Table 1	Emission Limits for New or Reconstructed Boilers and Process Heaters [c]
Table 3	Work Practice Standards
Table 9	Reporting Requirements
Table 10	Applicability of General Provisions to Subpart DDDDD
Table 14	Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters [c]

*****

SECTION E.15 NESHAP

Emissions Unit Description:

(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a rated maximum heat input capacity of 519 MMBtu per hour, each using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are intermediate load affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a rated maximum heat input capacity of 2,416 MMBtu per hour, using oxidation catalyst as control and CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR 60, Subpart KKKK, this unit is an affected facility]
[Under 40 CFR 60, Subpart TTTTa, this unit is an intermediate load affected facility]
[Under 40 CFR 63, Subpart YYYY, this unit is an affected source]

(o) Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a rated maximum capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a rated maximum heat input of 987 MMBtu per hour, using dry low-NOx combustors and voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

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

(a) Pursuant to 40 CFR 63.1 the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by

reference as 326 IAC 20-90, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 63, Subpart YYYY.

(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
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

E.15.2 Stationary Combustion Turbines NESHAP [40 CFR Part 63, Subpart YYYY] [326 IAC 20-90]

The Permittee shall comply with the following provisions of 40 CFR Part 63, Subpart YYYY (included as Attachment O to the operating permit), which are incorporated by reference as 326 IAC 20-90, for the emission unit(s) listed above:

63.6080	**What is the purpose of subpart YYYY?**
63.6085	**Am I subject to this subpart?**
63.6090	**What parts of my plant does this subpart cover?**
63.6092	**Are duct burners and waste heat recovery units covered by subpart YYYY?**
63.6095	**When do I have to comply with this subpart?**
63.6100	**What emission and operating limitations must I meet?**
63.6105(c)	**What are my general requirements for complying with this subpart?**
63.6110	**By what date must I conduct the initial performance tests or other initial compliance demonstrations?**
63.6115	**When must I conduct subsequent performance tests?**
63.6120	**What performance tests and other procedures must I use?**
63.6125(a)	**What are my monitor installation, operation, and maintenance requirements?**
63.6130	**How do I demonstrate initial compliance with the emission and operating limitations?**
63.6135	**How do I monitor and collect data to demonstrate continuous compliance?**
63.6140	**How do I demonstrate continuous compliance with the emission and operating limitations?**
63.6145	**What notifications must I submit and when?**
63.6150	**What reports must I submit and when?**
63.6155	**What records must I keep?**
63.6160	**In what form and how long must I keep my records?**
63.6165	**What parts of the General Provisions apply to me?**
63.6170	**Who implements and enforces this subpart?**
63.6175	**What definitions apply to this subpart?**
Tables to Subpart YYYY of Part 63	
Table 1	**Emission Limitations**
Table 2	**Operating Limitations**
Table 3	**Requirements for Performance Tests and Initial Compliance Demonstrations**
Table 4	**Initial Compliance With Emission Limitations**
Table 5	**Continuous Compliance With Operating Limitations**
Table 6	**Requirements for Reports**
Table 7	**Applicability of General Provisions to Subpart YYYY**

*****

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

Part 70 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Combustion Turbines 21A, 21B, 22A, and 22B
Parameter: Combined PM Emissions
Limit: Shall not exceed 120.3 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ **YEAR:**_____

Month	Column 1	Column 2	Column 1 + Column 2
	Combined PM Emissions (tons)	*Combined PM Emissions (tons)*	*Combined PM Emissions (tons)*
	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 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Combustion Turbines 21A, 21B, 22A, and 22B and their associated duct burners
Parameter: Combined NOx Emissions
Limit: Shall not exceed 1,566.3 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ **YEAR:**_____

Month	Column 1	Column 2	Column 1 + Column 2
	Combined NOx Emissions (tons)	*Combined NOx Emissions (tons)*	*Combined NOx Emissions (tons)*
	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 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Combustion Turbines 21A, 21B, 22A, and 22B
Parameter: Total VOC Emissions during any periods of startup and shutdown
Limit: Shall not exceed 25.6 tons per twelve (12) consecutive month period, during per combustion turbine, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____ CT: _____

Month	Column 1	Column 2	Column 1 + Column 2
	Total VOC Emissions (tons)	*Total VOC Emissions (tons)*	*Total VOC Emissions (tons)*
	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 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Combustion Turbines 21A, 21B, 22A, and 22B
Parameter: Total GHGs Emissions
Limit: Shall not exceed 850,447 tons per twelve (12) consecutive month period, per combustion turbine when operating in simple cycle mode including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____ CT: ___

Month	Column 1	Column 2	Column 1 + Column 2
	Total GHGs Emissions (tons)	*Total GHGs Emissions (tons)*	*Total GHGs Emissions (tons)*
	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 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Combustion Turbines 21A, 21B, 22A, and 22B
Parameter: Total GHGs Emissions
Limit: Shall not exceed 1,733,520 tons per twelve (12) consecutive month period, per combustion turbine when operating in combined cycle mode including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____ CT:___

Month	Column 1	Column 2	Column 1 + Column 2
	Total GHGs Emissions (tons)	*Total GHGs Emissions (tons)*	*Total GHGs Emissions (tons)*
	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 Quarterly Report~~

~~Source Name:~~ ~~Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station~~
~~Source Address:~~ ~~2723 East 1500 North, Wheatfield, Indiana 46392~~
~~Part 70 Permit No.:~~ ~~T 073-45762-00008~~
~~Facility:~~ ~~Source-wide~~
~~Parameter:~~ ~~Combined Total HAP Emissions~~
~~Limit:~~ ~~Shall be less than 25 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month~~

~~QUARTER:_____~~ ~~YEAR:_____~~

~~Month~~	~~Column 1~~	~~Column 2~~	~~Column 1 + Column 2~~
	~~*Total HAP Emissions (tons)*~~	~~*Total HAP Emissions (tons)*~~	~~*Total HAP Emissions (tons)*~~
	~~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 Quarterly Report

Source Name: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.: T 073-45762-00008
Facility: Source-wide
Parameter: Combined Single HAP (Formaldehyde) Emissions
Limit: Shall be less than 10 tons per twelve (12) consecutive month period, including periods of startup and shutdown, with compliance determined at the end of each month

QUARTER:_____ YEAR:_____

Month	Column 1	Column 2	Column 1 + Column 2
	Single HAP (Formaldehyde) Emissions (tons)	*Single HAP (Formaldehyde) Emissions (tons)*	*Single HAP (Formaldehyde) Emissions (tons)*
	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: _____

*****

Additional 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 listed below are due to the proposed modification. Deleted language appears as ~~strikethrough~~ text and new language appears as **bold** text (these changes may include Title I changes):

On March 15, 2021, EPA finalized the Revised Cross-State Air Pollution Rule (CSAPR) Update in order to resolve 21 states' outstanding interstate pollution transport obligations for the 2008 ozone National Ambient Air Quality Standards (NAAQS) (i.e., the 2008 ozone "good neighbor" provisions). Under this regulation, power plants in 12 states were required to participate in a new CASPR NOX Ozone Season Group 3 Trading Program (40 CFR 97, Subpart GGGGG). The new Group 3 trading program established in the rule was implemented starting May 1, 2021 (the first day of the 2021 ozone season), in which the Federal Implementation Plans (FIPs) would reduce NOx emissions from power plants in 12 states, including Indiana. The Group 3 Trading Program was stayed per 89 FR 87960, effective November 6, 2024.

On March 15, 2023, EPA finalized the Good Neighbor Plan to address 23 states' obligations to address interstate transport for the 2015 NAAQS. Under this new regulation, power plants in Indiana are required to participate in a revised version of the Group 3 Trading Program that was established under the Revised CSAPR Update rule. The Good Neighbor Plan (Group 3 Trading Program) was stayed per 89 FR 87960, effective November 6, 2024. EPA will implement this stay by recalling Group 3 Trading Program allowances and will record newly issued 2024 Group 2 allowances while the Good Neighbor Plan remains stayed. EPA further amended unit level allocations of emission allowances for Indiana EGUs on May 20, 2025 (90 FR 21423). The provisions of 40 CFR 97, Subpart EEEEE, applies while a stay is in place. Therefore, section H of this permit has been amended to incorporate these updates as applicable and all instances of "TR" have been changed to "CSAPR".

*****

SECTION H TR NO_X Annual Trading Program, TR NO_X Ozone Season **Group 2** Trading Program, and TR SO_2 Group 1 Trading Program Requirements (40 CFR 97.406), (40 CFR 97.~~5~~**8**06), (40 CFR 97.606)

ORIS Code: 994

Transport Rule (TR):

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(d) Three (3) aero-derivative natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, and 19C, approved in 2024 for construction, with a maximum rated heat input capacity of 519 MMBtu per hour, each using **oxidation catalyst as control and** CEMS for NOx emissions, and exhausting to stacks 19A, 19B, and 19C, respectively.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are intermediate load affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(e) One (1) frame-type natural gas-fired simple cycle combustion turbine, identified as Unit 20, approved in 2024 for construction, with a maximum rated heat input capacity of 2,416 MMBtu per hour, using **oxidation catalyst as control and** CEMS for NOx emissions, and exhausting to stack 20.

[Under 40 CFR 60, Subpart KKKK, this unit is an affected facility]

[Under 40 CFR 60, Subpart TTTTa, this unit is an intermediate load affected facility]
[Under 40 CFR 63, Subpart YYYY, this unit is an affected source]

(o) Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a maximum rated capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a maximum rated heat input of 987 MMBtu per hour, using dry low-NOx combustors and voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

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

H.1 Designated representative requirements

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with the following:

~~(a) 40 CFR 97.413 through 97.418.~~
~~(b) 40 CFR 97.513 through 97.518; and~~
~~(c) 40 CFR 97.613 through 97.618.~~

40 CFR 97 Subpart AAAAA - CSAPR NOx Annual Trading Program	
97.413	**Authorization of designated representative and alternate designated representative.**
97.414	**Responsibilities of designated representative and alternate designated representative.**
97.415	**Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.**
97.416	**Certificate of representation.**
97.417	**Objections concerning designated representative and alternate designated representative.**
97.418	**Delegation by designated representative and alternate designated representative.**
40 CFR 97 Subpart EEEEE - CSAPR NOX Ozone Season Group 2 Trading Program	

97.813	**Authorization of designated representative and alternate designated representative.**
97.814	**Responsibilities of designated representative and alternate designated representative.**
97.815	**Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.**
97.816	**Certificate of representation.**
97.817	**Objections concerning designated representative and alternate designated representative.**
97.818	**Delegation by designated representative and alternate designated representative.**
40 CFR 97 Subpart CCCCC - CSAPR SO2 Group 1 Trading Program	
97.613	**Authorization of designated representative and alternate designated representative.**
97.614	**Responsibilities of designated representative and alternate designated representative.**
97.615	**Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.**
97.616	**Certificate of representation.**
97.617	**Objections concerning designated representative and alternate designated representative.**
97.618	**Delegation by designated representative and alternate designated representative.**

H.2 Emissions monitoring, reporting, and recordkeeping requirements

(1) The owners and operators, and the designated representative, of each TR NO_X Annual source, TR NOx Ozone Season **Group 2** source, and TR SO2 Group 1 source, and each TR NO_X Annual unit at the source, TR NOx Ozone Season **Group 2** unit at the source, and TR SO2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430, 40 CFR 97.5**8**30, and 40 CFR 97.630 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431, 97.5**8**31, and 97.631 (initial monitoring system certification and recertification procedures), 97.432, 97.5**8**32, and 97.632 (monitoring system out-of-control periods), 97.433, 97.5**8**33, and 97.633 (notifications concerning monitoring), 97.434, 97.5**8**34, and 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435, 97.5**8**35, and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of TR NO_X Annual allowances under ~~40 CFR 97.411(a)(2) and (b) and 97.412~~ **326 IAC 24-5** and to determine compliance with the TR NO_X Annual emissions limitation and assurance provisions under Condition H.3 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(3) The emissions data determined in accordance with 40 CFR 97.5**8**30 through 97.5**8**35 shall be used to calculate allocations of TR NO_X Ozone Season **Group 2** allowances under 40 CFR 97.5**8**11(a)(2) and (b) and 97.5**8**12 and to determine compliance with the TR NO_X Ozone Season **Group 2** emissions limitation and assurance provisions under Condition H.4 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.5**8**30 through 97.5**8**35 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(4) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of TR SO_2 Group 1 allowances under ~~40 CFR 97.611(a)(2) and (b) and 97.612~~ **326 IAC 24-7** and to determine compliance with the TR SO_2 Group 1 emissions limitation and assurance provisions under Condition H.5 below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

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H.4 NOx ozone season **Group 2** requirements

(1) TR NO_X Ozone Season **Group 2** emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_X Ozone Season **Group 2** source and each TR NO_X Ozone Season **Group 2** unit at the source shall hold, in the source's compliance account, TR NO_X Ozone Season **Group 2** allowances available for deduction for such control period under 40 CFR 97.5**8**24(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Ozone Season **Group 2** units at the source.

(ii). If total NO_X emissions during a control period in a given year from the TR NO_X Ozone Season **Group 2** units at a TR NO_X Ozone Season **Group 2** source are in excess of the TR NO_X Ozone Season **Group 2** emissions limitation set forth in Condition H.4(1)(i) above, then:

(A). The owners and operators of the source and each TR NO_X Ozone Season **Group 2** unit at the source shall hold the TR NO_X Ozone Season **Group 2** allowances required for deduction under 40 CFR 97.5**8**24(d); and

(B). The owners and operators of the source and each TR NO_X Ozone Season **Group 2** unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart **EEEEE**~~BBBBB~~ and the Clean Air Act.

(2) TR NO_X Ozone Season **Group 2** assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all TR NO_X Ozone Season **Group 2** units at TR NO_X Ozone Season **Group 2** sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_X Ozone Season **Group 2** allowances available for deduction for such control period under 40 CFR 97.~~5~~**8**25(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.~~5~~**8**25(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total NO_X emissions from all TR NO_X Ozone Season **Group 2** units at TR NO_X Ozone Season **Group 2** sources in the state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the TR NO_X Ozone Season **Group 2** allowances required under Condition H.4(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NO_X emissions from all TR NO_X Ozone Season **Group 2** units at TR NO_X Ozone Season **Group 2** sources in the state during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season **Group 2** trading budget under 40 CFR 97.~~5~~**8**10(a) and the state's variability limit under 40 CFR 97.~~5~~**8**10(b).

(iv). It shall not be a violation of 40 CFR part 97, subpart **EEEEE**~~BBBBB~~ or of the Clean Air Act if total NO_X emissions from all TR NO_X Ozone Season **Group 2** units at TR NO_X Ozone Season **Group 2** sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the TR NO_X Ozone Season **Group 2** units at TR NO_X Ozone Season **Group 2** sources in the state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold TR NO_X Ozone Season **Group 2** allowances for a control period in a given year in accordance with Condition H.4(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each TR NOX Ozone Season **Group 2** allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (d)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart **EEEEE**~~BBBBB~~ and the Clean Air Act.

(3) Compliance Periods.

(i). A TR NOx Ozone Season **Group 2** unit shall be subject to the requirements under Condition H.4(1) above for the control period starting on the later of May 1, 2015 or the deadline for meeting the unit's monitor certificate requirements under 40 CFR 97.~~5~~**8**30(b) and for each control period thereafter.

(ii). A TR NOx Ozone Season **Group 2** unit shall be subject to the requirements under Condition H.4(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.~~5~~**8**30(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A TR NOx Ozone Season **Group 2** allowance held for compliance with the requirements under Condition H.4(1)(i) above for a control period in a given year must be a TR NOx Ozone Season **Group 2** allowance that was allocated for such control period or a control period in a prior year.

(ii). A TR NOx Ozone Season **Group 2** allowance held for compliance with the requirements under Condition H.4(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a TR NOx Ozone Season allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowances Management System Requirements.

(i). Each TR NOx Ozone Season **Group 2** allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart **EEEEE**~~BBBBB~~.

(6) Limited Authorization.

(i). A TR NOx Ozone Season **Group 2** allowance is a limited authorization to emit one ton of NOx during the control period in one year. Such authorization is limited in its use and duration as follows:

(A). Such authorization shall only be used in accordance with the TR NOx Ozone Season **Group 2** Trading Program; and

(B). Notwithstanding any other provision of 40 CFR Part 97, Subpart **EEEEE**~~BBBBB~~, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property Right.

(i). A TR NOx Ozone Season **Group 2** allowance does not constitute a property right.

*****

H.6 Title V Permit Revision Requirements

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_X Annual allowances in accordance with 40 CFR part 97, subpart AAAAA, TR NO_X Ozone Season **Group 2** allowances in accordance with 40 CFR part 97, subpart **EEEEE**~~BBBBB~~, and TR SO_2 Group 1 allowances in accordance with 40 CFR part 97, subpart CCCCC.

(2) This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, 40 CFR 97.~~5~~**8**30 through 97.~~5~~**8**35, and 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2), 40 CFR 97.~~5~~**8**06(d)(2), and 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

H.7 Additional recordkeeping and reporting requirements

(1) Unless otherwise provided, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit, TR NO_X Ozone Season **Group 2** source and each TR NO_X Ozone Season **Group 2** unit, and TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.416, 40 CFR 97.~~5~~**8**16, and 40 CFR 97.616 for the designated representative for the source and each TR NO_X Annual unit, TR NOx Ozone Season **Group 2** unit, and TR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of

representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416, 40 CFR 97.5**8**16, and 40 CFR 97.616 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR part 97, subpart AAAAA, 40 CFR part 97, subpart **EEEEE**~~BBBBB~~, and 40 CFR part 97, subpart CCCCC.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NO_X Annual Trading Program, TR NO_X Ozone Season **Group 2** Trading Program, and TR SO_2 Group 1 Trading Program.

(2) The designated representative of a TR NO_X Annual source and each TR NO_X Annual unit, a TR NO_X Ozone Season **Group 2** source and each TR NO_X Ozone Season **Group 2** unit, and a TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall make all submissions required under the TR NO_X Annual Trading Program, TR NO_X Ozone Season **Group 2** Trading Program, and TR SO_2 Group 1 Trading Program, except as provided in 40 CFR 97.418, 40 CFR 97.5**8**18, and 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

H.8 Liability

(1) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual source or the designated representative of a TR NO_X Annual source shall also apply to the owners and operators of such source and of the TR NO_X Annual units at the source.

(2) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual unit or the designated representative of a TR NO_X Annual unit shall also apply to the owners and operators of such unit.

(3) Any provision of the TR NO_X Ozone Season **Group 2** Trading Program that applies to a TR NO_X Ozone Season **Group 2** source or the designated representative of a TR NO_X Ozone Season **Group 2** source shall also apply to the owners and operators of such source and of the TR NO_X Ozone Season **Group 2** units at the source.

(4) Any provision of the TR NO_X Ozone Season **Group 2** Trading Program that applies to a TR NO_X Ozone Season **Group 2** unit or the designated representative of a TR NO_X Ozone Season **Group 2** unit shall also apply to the owners and operators of such unit.

*****

H.9 Effect on other authorities

No provision of the TR NO_X Annual Trading Program or exemption under 40 CFR 97.405, TR NO_X Ozone Season **Group 2** Trading Program or exemption under 40 CFR 97.5**8**05, and TR SO_2 Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_X Annual source or TR NO_X Annual unit, TR NO_X Ozone Season **Group 2** source or TR NO_X Ozone Season **Group 2** unit, and TR SO_2 Group 1 source or TR SO_2 Group 1 unit from compliance with

any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

H.10 Description of TR Monitoring Provisions

The TR subject unit(s) and the unit-specific monitoring provisions at this source are identified in the following table(s). These units are subject to the requirements for the TR NOx Annual Trading Program and TR NOx Ozone Season **Group 2** Trading Program and TR SO2 Group 1 Trading Program.

*****

Unit ID: 21A, 21B, 22A, and 22B					
Parameter	**Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)**	**Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D**	**Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E**	**Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19**	**EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E**
SO_2	-------	**X**	-------	-------	-------
NO_X	**X**	-------	-------	-------	-------
Heat input	-------	**X**	-------	-------	-------

(1) The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (TR NOX Annual Trading Program), 97.~~5~~**8**30 through 97.~~5~~**8**35 (TR NOx Ozone Season **Group 2** Trading Program), and 97.630 through 97.635 (TR SO2 Group 1 Trading Program), as applicable. The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable TR trading programs.

(2) Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

(3) Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program), 97.~~5~~**8**35 (TR NOx Ozone Season **Group 2** Trading Program), and 97.635 (TR SO_2 Group 1 Trading Program), as applicable. The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(4) Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program), 97.~~5~~**8**30 through 97.~~5~~**8**34 (TR NOx Ozone Season **Group 2** Trading Program), and 97.630 through 97.634 (TR SO_2 Group 1 Trading Program), as applicable, must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (TR NOx Annual Trading Program), 97.~~5~~**8**35 (TR NOx Ozone Season **Group 2** Trading Program), and 97.635 (TR SO_2 Group 1 Trading Program), as applicable. The

Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(5) The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (TR NOx Annual Trading Program), 97.~~5~~**8**30 through 97.~~5~~**8**34 (TR NOx Ozone Season **Group 2** Trading Program), and 97.630 through 97.634 (TR SO_2 Group 1 Trading Program), as applicable, and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add to or change this unit's monitoring system description.

Proposed Changes Due to Emergency Affirmative Defense Removal

In the Federal Register Notice 88 FR 47029 dated July 21, 2023, U.S. EPA finalized the removal of the "emergency" affirmative defense provisions from Clean Air Act operating permit program regulations effective August 21, 2023. A rulemaking to amend the Indiana rules at 326 IAC 2-7 (Part 70 Permit Program), 326 IAC 2-8 (Federally Enforceable State Operating Permit Program), and 326 IAC 1-6-1 (Malfunctions) was effective June 21, 2025, making them consistent with federal regulations. IDEM OAQ has determined that changes to the permit are required to be consistent with state and federal law. The permit is revised as shown below with deleted language as ~~strikeouts~~ and new language **bolded**.

(a) The permit is amended to remove Section B - Emergency Provisions and replace the section title with the word "Reserved", to remove the Emergency Occurrence Report form, and to remove any references to the requirements of Section B - Emergency Provisions from permit conditions.

(b) The permit is amended to include a new Section C - Malfunctions Report (and a new associated Malfunctions Report form) that incorporates the record keeping and reporting requirements of 326 IAC 1-6-2 (Records; Notice of Malfunction). All subsequent Section C conditions are renumbered accordingly. Permit Section C - General Reporting Requirements and the Quarterly Deviation And Compliance Monitoring Report form is amended to reference Section C - Malfunctions Report.

(c) Permit citations to definitions within 326 IAC 2-7-1 are amended throughout the permit as necessary, since the definitions under 326 IAC 2-7-1(12) and 326 IAC 2-7-1(20) have been deleted from the rule. Any occurrence of the following 326 IAC 2-7-1 definition citations are amended as shown below, with deleted language as strikeouts and new language **bolded**:

326 IAC 2-7-1~~(21)~~**(19)**
326 IAC 2-7-1~~(22)~~**(20)**
326 IAC 2-7-1~~(33)~~**(31)**
326 IAC 2-7-1~~(35)~~**(33)**
326 IAC 2-7-1~~(37)~~**(35)**
326 IAC 2-7-1~~(42)~~**(39)**

(d) If necessary, any permit conditions and forms that contain the IDEM OAQ mailing address have been updated throughout the permit as follows with deleted language as strikeouts and new language **bolded**:

*****
~~100 North Senate Avenue~~
~~MC 61-53 IGCN 1003~~
Indiana Government Center North
100 North Senate Avenue, Room 13W

*****
~~100 North Senate Avenue~~
~~MC 61-50 IGCN 1003~~

Indiana Government Center North
100 North Senate Avenue, Room 13W

*****

(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 8, 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.

*****

A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)][326 IAC 2-7-1(~~22~~**20**)]

*****

A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(~~21~~**19**)] [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~~**19**):

*****

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

*****

(a) It is a major source, as defined in 326 IAC 2-7-1(~~22~~**20**);

*****

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

*****

(1) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(~~35~~**33**), and

*****

(c) A "responsible official" is defined at 326 IAC 2-7-1(~~35~~**33**).

*****

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

*****

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~~**33**).

*****

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

*****

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~~**33**).

*****

(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~~**33**).

*****

B.11 **Reserved**

~~Emergency Provisions [326 IAC 2-7-16]~~

~~(a) An emergency, as defined in 326 IAC 2-7-1(12), is not an affirmative defense for an action brought for noncompliance with a federal or state health-based emission limitation.~~

~~(b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describe the following:~~

~~(1) An emergency occurred and the Permittee can, to the extent possible, identify the causes of the emergency;~~

~~(2) The permitted facility was at the time being properly operated;~~

~~(3) During the period of an emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;~~

~~(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;~~

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

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

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

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

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

~~(A) A description of the emergency.~~

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

~~(C) Corrective actions taken.~~

~~The notification which shall be submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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.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~~**33**).

*****

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~~**19**) and 326 IAC 2-7-1(~~42~~**39**). 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~~**33**).

*****

B.17 Permit Amendment or Modification [326 IAC 2-7-11][326 IAC 2-7-12] [40 CFR 72]

*****

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~~**33**).

*****

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

*****

(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~~**35**)) 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:

*****

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~~**33**).

*****

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

*****

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~~**33**).

*****

C.8 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

*****

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~~**33**).

*****

C.9 Performance Testing [326 IAC 3-6]

*****

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~~**33**).

*****

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. In the event that a previously scheduled test must be canceled and rescheduled, the Permittee of the source or emissions unit shall notify the department no less than fourteen (14) days in advance of the rescheduled test date. Tests rescheduled for less than fourteen (14) days after notifying the department of the

rescheduled test date must be approved by the department. 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~~**33**).

*****

C.11 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)][40 CFR 64][326 IAC 3-8]

*****

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~~**33**).

*****

C.18 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5][326 IAC 2-7-6]

*****

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~~**33**).

*****

C.19 Malfunctions Report [326 IAC 1-6-2]

Pursuant to 326 IAC 1-6-2 (Records; Notice of Malfunction):

(a) A record of all malfunctions, startups, or shutdowns of any emission unit or emission control equipment, that result in violations of applicable air pollution control regulations or applicable emission limitations must be kept and retained for a period of three (3) years and shall be made available to the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ) or appointed representative upon request.

(b) When a malfunction of any emission unit or emission control equipment: 1) results in violations of applicable air pollution control regulations or applicable emissions limitations and 2) lasts more than one (1) hour, the condition shall be reported to OAQ, using the Malfunction Report Forms (2 pages) or its equivalent. Notification must be made by telephone or other electronic means, as soon as practicable, but in no event later than four (4) daytime business hours after the beginning of the occurrence.

(c) Failure to report a malfunction under subsection (b) of this condition of any emission unit or emission control equipment shall constitute a violation of 326 IAC 1-6, and any other applicable rules. Information of the scope and expected duration of the malfunction must be provided, including the items specified in 326 IAC 1-6-2(c)(3)(A) through (E).

(d) Malfunction is defined as any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner. [326 IAC 1-2-39]

*****

C.**20**~~19~~ 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]

*****

(2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(~~33~~**31**) (“Regulated pollutant, which is used only for purposes of Section 19 of this rule”) from the source, for purpose of fee assessment.

*****

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~~**33**).
*****

C.**21**~~20~~ General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]
*****

C.**22**~~21~~ General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [40 CFR 64][326 IAC 3-8]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under ~~Section B - Emergency Provisions~~ **Section C - Malfunctions Report** 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~~**33**). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

*****

C.**23**~~22~~ Compliance with 40 CFR 82 and 326 IAC 22-1
*****

D.3.16 Reporting Requirements

(a) Pursuant to 326 IAC 3-5-7, a quarterly report of PM, SO2, and NOx exceedances shall be submitted not later than thirty (30) days following the end of each calendar quarter. 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~~**33**). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

*****

(c) Pursuant to 326 IAC 3-5-5(e), a quarterly report of the continuous emissions monitoring system performance audits shall be submitted not later than thirty (30) days following the end of each calendar quarter. 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~~**33**). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(d) Pursuant to 326 IAC 3-5-7(5), a quarterly report of the continuous monitoring system instrument downtime shall be submitted not later than thirty (30) days following the end of each calendar quarter. 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~~**33**). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

*****

D.4.9 Reporting Requirements

*****

The report submitted by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(~~35~~**33**).

(b) To document the compliance status with Condition D.4.1(b), the Permittee shall submit a quarterly summary of the hours of operation for each combustion turbine. These reports shall be submitted to the address listed in Section C - General Reporting Requirements, of this approval. 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~~**33**). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

Specifically Regulated Insignificant Activities [326 IAC 2-7-1(~~21~~**19**)]:

*****

D.6.7 Record Keeping Requirements

Specifically Regulated Insignificant Activities [326 IAC 2-7-1(~~21~~**19**)]:

*****

D.8.4 Broken or Failed Bag Detection

In the event that bag failure has been observed:

For bin vent filters, if failure is indicated by an opacity violation, or if filter failure is determined by other means, such as gas temperatures, flow rates, air infiltration, leaks, dust traces or triboflows, then failed unit and the associated process will be shut down immediately until the failed unit has been repaired or replaced. ~~Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions).~~

*****

D.10.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

Specifically Regulated Insignificant Activities [326 IAC 2-7-1(~~21~~**19**)]:

*****

D.13.9 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

*****

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~~**33**).
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~~**33**).

*****

D.13.10 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.13.1 shall be submitted not later than thirty (30) days after the end of the quarter being reported. 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~~**33**). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

*****

D.14.14 Reporting Requirements for CEMS [326 IAC 2-7-5(3)(C)] [326 IAC 3-5]

*****

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~~**33**).

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~~**33**).

*****

D.14.15 Reporting Requirements

A quarterly summary of the information to document the compliance status with Conditions D.14.3(a) and D.14.3(b) shall be submitted not later than thirty (30) days after the end of the quarter being reported. 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~~**33**). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

*****

~~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: Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station~~
~~Source Address: 2723 East 1500 North, Wheatfield, Indiana 46392~~
~~Part 70 Permit No.: T 073-45762-00008~~

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

~~□ This is an emergency as defined in 326 IAC 2-7-1(12)~~
- ~~The Permittee must notify the Office of Air Quality (OAQ), within four (4) 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: _____~~

*****

MALFUNCTION REPORT

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
FAX NUMBER: (317) 233-6865
EMAIL: AirCompl@idem.in.gov

Source Name: **Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station**
Source Address: **2723 East 1500 North, Wheatfield, Indiana 46392**
Permit No.: **T 073-45762-00008**

For any malfunction lasting one (1) hour or longer, the Permittee must submit this form to the Office of Air Quality (OAQ), within four (4) daytime business hours of malfunction start.

If any of the following are not applicable, mark N/A. This form consists of two (2) pages.

Page 1 of 2

This malfunction resulted in a violation of the following Indiana Administrative Code, permit condition, and/or permit limit and meets the definition of "malfunction" as listed on reverse side (e.g., 326 IAC 5-1, Permit Condition D.1.1, 40 CFR 60.62, etc.):

Describe affected facility/equipment/operation (e.g., Coating Line #2, Boiler D, Diesel engine, No. 3 smelter, etc.):

Control equipment (e.g., Baghouse B4, Thermal oxidizer for Paint Line #1, etc.):	
Description of the malfunction and cause:	
When the malfunction started:	**Date (MM/DD/YYYY):**
	Time (HH:MM):
When the malfunction was corrected or is expected to be corrected:	**Date (MM/DD/YYYY):**
	Time (HH:MM):

Type of pollutant(s) emitted (e.g., PM, PM10, PM2.5, VOC, etc.):
Estimated amount of pollutant(s) emitted during malfunction (e.g., VOC at 35 lbs/hr, 5 tons of PM, etc.):
Describe the corrective actions and interim control measures taken to minimize emissions (e.g., shut coating line down, isolated failing baghouse compartment, idled furnace operations until repairs completed, etc.):

Form completed by:_____

Title/position: _____

Signature: _____

Date: _____

Phone: _____

Email:_____

326 IAC 1-6-1 Applicability of rule

Sec. 1. This rule applies to the owner or operator of any facility required to obtain a permit under 326 IAC 2-5.1, 326 IAC 2-6.1, 326 IAC 2-7, or 326 IAC 2-8.

326 IAC 1-2-39 "Malfunction" definition

Sec. 39. Any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner.

*****

QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name:	Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station
Source Address:	2723 East 1500 North, Wheatfield, Indiana 46392
Part 70 Permit No.:	T 073-45762-00008

This report shall be submitted quarterly based on a calendar year. Proper notice submittal under ~~Section B - Emergency Provisions~~ **Section C - Malfunctions Report** 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".

*****

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 September 5, 2025.

The construction of this proposed modification shall be subject to the conditions of the attached proposed Part 70 PSD/Significant Source Modification No. 073-49556-00008. The operation of this proposed modification shall be subject to the conditions of the attached proposed Significant Permit Modification No. 073-49651-00008.

The staff recommends to the Commissioner that the Part 70 Significant Source Modification and Significant Permit Modification be approved.

IDEM Contact

(a) If you have any questions regarding this draft permit, please contact Hachem Ismaili Alaoui, Indiana Department Environmental Management, Office of Air Quality, Permits Branch, Indiana Government Center North, 100 North Senate Avenue, Room 13W, Indianapolis, Indiana 46204-2251, or by telephone at (317) 232-2827 or (800) 451-6027, and ask for Hachem Ismaili Alaoui or (317) 232-2827.

(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: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

Appendix A: Emission Calculations
Potential to Emit Summary

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Uncontrolled Potential to Emit (tons/year)												
Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**H2SO4**	**GHGs**	**Total HAPs**	**Worst Single HAP**	
Temporary Boiler	0.82	3.26	3.26	0.26	15.92	2.36	16.17	--	51,784	0.81	0.77	Hexane
Dry bottom pulverized coal-fired boiler- Unit 17	69,589	16,006	16,006	95,079	9,383	46.91	390.95	>100	3,768,728	1211.34	938.28	HCl
Dry bottom pulverized coal-fired boiler- Unit 18	69,589	16,006	16,006	95,079	9,383	46.91	390.95	>100	3,768,728	1211.34	938.28	HCl
Units 17 and 18 Cooling Towers	156.70	109.69	65.81	--	--	--	--	--	--	--	--	--
Turbine 16A	41.92	41.92	41.92	21.49	2,032	13.34	520.78	--	705,188	7.90	4.51	Formaldehyde
Turbine 16B	41.92	41.92	41.92	21.49	2,032	13.34	520.78	--	705,188	7.90	4.51	Formaldehyde
Turbines 19A, 19B, and 19C	42.45	78.54	78.54	13.24	595.38	52.85	212.24	21.13	1,042,294	15.99	12.09	Formaldehyde
Turbine 20	36.43	69.93	69.93	20.52	602.99	63.91	312.45	30.41	1,500,366	10.82	4.82	Formaldehyde
Turbines 21A, 21B, 22A, and 22B	220.40	428.31	428.31	121.05	2,585.88	363.58	638.66	135.37	10,556,986	78.58	46.43	Hexane
Radial Sackers (7MX04G-RS & 8MX04G-RS)	3.30	1.56	0.24	0.00	0.00	0.00	0.00	--	0.00	0.00	0.00	N/A
Unit 17 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	--	0.00	0.00	0.00	N/A
Unit 18 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	--	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Unpaved Roads	0.01	0.00	0.00	0.00	0.00	0.00	0.00	--	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Paved Roads	0.02	0.00	0.00	0.00	0.00	0.00	0.00	--	0.00	0.00	0.00	N/A
334 HP Diesel Fire Pump	0.19	0.19	0.19	0.18	2.71	0.22	0.58	--	100.95	2.37E-03	7.23E-04	Formaldehyde
Emergecy Generator EDG1	0.24	0.29	0.28	0.01	7.69	0.47	4.20	2.66E-04	850.48	8.05E-03	3.97E-03	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	5.03E-03	94.32	2.22E-03	6.75E-04	Benzene
Peaker - Circuit Breakers	--	--	--	--	--	--	--	--	85.19	--	--	--
Peaker - Piping Fugitives	--	--	--	--	--	0.43	--	--	570.18	--	--	--
Auxilary Boilers (AUX1 and AUX2)	1.88	7.51	7.51	0.59	138.27	5.43	82.96	--	118749	1.86	1.78	Hexane
CCCT - Cooling Towers (CTH1 and CTH2)	12.27	7.79	0.03	--	--	--	--	--	--	--	--	--
Dew Point Heater	0.23	0.91	0.91	0.07	12.02	0.66	10.10	--	14506	0.23	0.22	Hexane
Emergency Generators (EDGCC1 and EDGCC2)	0.55	0.67	0.65	0.02	17.64	1.08	9.65	6.10E-04	1952	0.02	0.009	PAH
Emergency Fire Pumps (FPCC1 and FPCC2)	0.05	0.36	0.36	0.34	1.08	0.00	0.94	1.01E-02	188.64	0.004	0.001	Formaldehyde
Lube Oil Demister Vents	0.00	0.35	0.35	--	--	0.35	--	--	--	--	--	--
CCCT - Circuit Breakers	--	--	--	--	--	--	--	--	1022.25	--	--	--
CCCT - Piping Fugitives	--	--	--	--	--	1.52	--	--	2023.69	--	--	--
Diesel Storage Tank (TKCC1)	--	--	--	--	--	0.00	--	--	--	--	--	--
Total	**139740**	**32806**	**32753**	**190358**	**26810**	**613**	**3112**	**>100**	**22239406**	**2547**	**1877**	**HCl**

Appendix A: Emission Calculations
Potential to Emit Summary

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Limited Potential to Emit (tons/year)

Emission Unit	PM	PM10	PM2.5	SO2	NOx	VOC	CO	H2SO4	GHGs	Total HAPs	Worst Single HAP	
Temporary Boiler	0.82	3.26	3.26	0.26	15.92	2.36	16.17	--	51,784	0.81	0.77	Hexane
Dry bottom pulverized coal-fired boiler- Unit 17	91.00	345.00	292.00	95,079	1,599.00	46.91	391	280.00	3,768,728	1211.34	938.28	HCl
Dry bottom pulverized coal-fired boiler- Unit 18				95,079		46.91	391		3,768,728	1211.34	938.28	HCl
Units 17 and 18 Cooling Towers				--	--	--	--		--	--	--	--
Turbine 16A	9.57	9.57	9.57	4.91	464.00	3.05	118.90	--	161,002	2.01	1.03	Formaldehyde
Turbine 16B	9.57	9.57	9.57	4.91	464.00	3.05	118.90	--	161,002	2.01	1.03	Formaldehyde
Turbines 19A, 19B, and 19C	38.64	78.54	78.54	13.24	595.38	72.34	212.24	21.13	530,244	15.99	12.09	Formaldehyde
Turbine 20		69.93	69.93	20.52	602.99		312.45	30.41	701,784	10.82	4.82	Formaldehyde
Turbines 21A, 21B, 22A, and 22B	120.3	228.02	228.02	121.05	1,566.3	363.58	638.66	135.37	10,556,986	78.58	46.43	Hexane
Radial Sackers (7MX04G-RS & 8MX04G-RS)	3.30	1.56	0.24	0.00	0.00	0.00	0.00	--	0.00	0.00	0.00	N/A
Unit 17 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	--	0.00	0.00	0.00	N/A
Unit 18 ACI System	0.91	0.91	0.91	0.00	0.00	0.00	0.00	--	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Unpaved Roads	0.01	0.00	0.00	0.00	0.00	0.00	0.00	--	0.00	0.00	0.00	N/A
Unit 17 & 18 ACI Paved Roads	0.02	0.00	0.00	0.00	0.00	0.00	0.00	--	0.00	0.00	0.00	N/A
334 HP Diesel Fire Pump	0.19	0.19	0.19	0.18	2.71	0.22	0.58	--	100.95	2.37E-03	7.23E-04	Formaldehyde
Emergecy Generator EDG1	0.24	0.29	0.28	0.01	7.69	0.47	4.20	2.66E-04	850.48	8.05E-03	3.97E-03	Benzene
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	5.03E-03	94.32	2.22E-03	6.75E-04	Benzene
Peaker - Circuit Breakers	--	--	--	--	--	--	--	--	85.19	--	--	--
Peaker - Piping Fugitives	--	--	--	--	--	0.43	--	--	570.18	--	--	--
Auxilary Boilers (AUX1 and AUX2)	1.88	7.51	7.51	0.59	138.27	5.43	82.96	--	118749	1.86	1.78	Hexane
CCCT - Cooling Towers (CTH1 and CTH2)	12.27	7.79	0.03	--	--	--	--	--	--	--	--	--
Dew Point Heater	0.23	0.91	0.91	0.07	12.02	0.66	10.10	--	14506	0.23	0.22	Hexane
Emergency Generators (EDGCC1 and EDGCC2)	0.55	0.67	0.65	0.02	17.64	1.08	9.65	6.10E-04	1952	0.02	0.009	PAH
Emergency Fire Pumps (FPCC1 and FPCC2)	0.05	0.36	0.36	0.34	1.08	0.00	0.94	1.01E-02	188.64	0.004	0.001	Formaldehyde
Lube Oil Demister Vents	0.00	0.35	0.35	--	--	0.35	--	--	--	--	--	--
CCCT - Circuit Breakers	--	--	--	--	--	--	--	--	1022	--	--	--
CCCT - Piping Fugitives	--	--	--	--	--	1.52	--	--	2024	--	--	--
Diesel Storage Tank (TKCC1)	--	--	--	--	--	0.001	--	--	--	--	--	--
Total	**290**	**766**	**703**	**190325**	**5488**	**548.46**	**2308**	**>100**	**19840401**	**2535**	**1945**	**HCl**

Appendix A: Emission Calculations
Modofication Summary

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Uncontrolled PTE of New Units (ton/yr)										
	PM	PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO	Total HAPs	Single HAPs	
Turbines 21A, 21B, 22A, and 22B	220.40	428.31	428.31	121.05	2585.88	363.58	638.66	78.58	46.43	Hexane
Auxiliary Boilers AUX1 and AUX2	1.88	7.51	7.51	0.59	138.27	5.43	82.96	1.86	1.78	Hexane
CCCT - Cooling Towers CTH1 and CTH2	12.27	7.79	0.03	--	--	--	--	--	--	--
Dew Point Heater	0.23	0.91	0.91	0.07	12.02	0.66	10.10	0.23	0.22	Hexane
Lube Oil Demister Vents	0.00	0.35	0.35	--	--	0.35	--	--	--	--
Emergency Generators EDGCC1 and EDGCC2	0.55	0.67	0.65	0.02	17.64	1.08	9.65	0.018	0.009	PAH
Emergency Fire Pumps FPCC1 and FPCC2	0.05	0.36	0.36	0.34	1.08	0.00	0.94	0.004	0.001	Formaldehyde
CCCT - Circuit Breakers	--	--	--	--	--	--	--	--	--	--
CCCT - Piping Fugitives	--	--	--	--	--	1.52	--	--	--	--
Diesel Storage Tank TKCC1	--	--	--	--	--	0.001	--	--	--	--
Peaker - Circuit Breakers	--	--	--	--	--	--	--	--	--	--
Peaker - Piping Fugitives	--	--	--	--	--	0.43	--	--	--	--
Total	***235.38***	***445.90***	***438.12***	***122.07***	***2754.89***	***373.04***	***742.31***	***80.69***	***48.42***	**Hexane**

Appendix A: Emission Calculations
PSD Significance Determination

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

2026 CCCT Project Emissons

Unlimited PTE of New Emission Units (ton/yr)									
Emission Units	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**H2SO4**	**CO2e**
Units 21A, 21B, 22A, and 22B Simple Cycle Mode	143.75	287.50	287.50	90.84	3465.57	257.65	545.35	135.37	7,830,526
Units 21A, 21B, 22A, and 22B Combined Cycle Mode	220.40	428.31	428.31	121.05	2585.88	363.58	638.66	78.35	10,556,986
Maximum for Operating Modes	220.40	428.31	428.31	121.05	3465.57	363.58	638.66	135.37	10556986
Auxiliary Boilers AUX1 and AUX2	1.88	7.51	7.51	0.59	138.27	5.43	82.96	0.00	118,749
CCCT - Cooling Towers CTH1 and CTH2	12.27	7.79	0.03	--	--	--	--	--	--
Dew Point Heater DPH1	0.23	0.91	0.91	0.07	12.02	0.66	10.10	0.00	14,506
Lube Oil Tanks Demister Vents	0.00	0.35	0.35	--	--	0.35	--	--	--
Emergency Generators EDGCC1 and EDGCC2	0.55	0.67	0.65	0.02	17.64	1.08	9.65	0.00	1,952
Emergency Fire Pumps FPCC1 and FPCC2	0.05	0.36	0.36	0.34	1.08	0.00	0.94	0.01	189
CCCT - Circuit Breakers	--	--	--	--	--	--	--	--	1,022
CCCT - N.G Piping Fugitives	--	--	--	--	--	1.52	--	--	2024
Diesel Storage Tank TKCCT	--	--	--	--	--	0.00	--	--	--
Total	***235.38***	***445.90***	***438.12***	***122.07***	***3634.58***	***372.61***	***742.31***	***135.38***	***10695428***

Limited PTE of New Emission Units (ton/yr)									
Emission Units	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**H2SO4**	**CO2e**
Units 21A, 21B, 22A, and 22B Simple Cycle Mode	61.25	122.49	122.49	38.57	1462.88	164.38	382.39	57.48	3,401,786
Units 21A, 21B, 22A, and 22B Combined Cycle Mode	120.25	228.02	228.02	79.99	1566.28	249.94	510.49	44.20	6,934,113
Maximum for Operating Modes	120.25	228.02	228.02	79.99	1566.28	249.94	510.49	57.48	6934113
Auxiliary Boilers AUX1 and AUX2	1.88	7.51	7.51	0.59	138.27	5.43	82.96	0.00	118749
CCCT - Cooling Towers CTH1 and CTH2	12.27	7.79	0.03	--	--	--	--	--	--
Dew Point Heater DPH1	0.23	0.91	0.91	0.07	12.02	0.66	10.10	0.00	14506
Lube Oil Tanks Demister Vents	0.00	0.35	0.35	--	--	0.35	--	--	--
Emergency Generators EDGCC1 and EDGCC2	0.55	0.67	0.65	0.02	17.64	1.08	9.65	0.00	1952
Emergency Fire Pumps FPCC1 and FPCC2	0.05	0.36	0.36	0.34	1.08	0.00	0.94	0.01	189
CCCT - Circuit Breakers	--	--	--	--	--	--	--	--	1022
CCCT - N.G Piping Fugitives	--	--	--	--	--	1.52	--	--	2024
Diesel Storage Tank TKCCT	--	--	--	--	--	0.00	--	--	--
Total	***135.24***	***245.62***	***237.83***	***81.01***	***1735.29***	***258.97***	***614.14***	***57.49***	***7072554***

Appendix A: Emission Calculations
PSD Significance Determination

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Projected commence construction date first CT	May-2026		
Projected start of operation date first CT	Sep-2030		
Contemporaneous period	Jun-2021	to	Sep-2030

Contemporaneous changes

Unit 15 shutdown	Sep-2021	
2024 Peaker Project last CT startup	Dec-2027	(Projected)
Unit 17 and Cooling Tower New Limitation	Future	
Unit 18 and Cooling Tower New Limitaion	Future	

Contemporaneous Emissions Decrease (ton/yr)									
Process/Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**H2SO4**	**CO2e**
Unit 15 Shutdown in 2021 (Baseline period 2018-2019)									
Projected Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Baseline Actual Emissions	68.26	259.64	246.04	171.54	1448.14	36.21	4622.34	4.63	2380454
BAE (Unit 15)	-68.26	-259.64	-246.04	-171.54	-1448.14	-36.21	-4622.34	-4.63	-2380454
Unit 15 BAE	***-68.26***	***-259.64***	***-246.04***	***-171.54***	***-1448.14***	***-36.21***	***-4622.34***	***-4.63***	***-2380454***

In accordance with 326 IAC 2-2-1(e)(1), NIPSCO is requesting the IDEM commissioner to use period from March 2021 to Feb 2023 as representative of nomal source operation for Unit 17 and Unit 18 and their associated cooling towers.

Actual Emissions (ton/yr)									
Process/Emission Unit	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**H2SO4**	**CO2e**
Units 17 & 18 and Cooling Towers for Units 17 & 18 (Baseline Actual Emissions for Period from March 2021 to Feb 2023)									
Unit 17 Actual Emissions	25.80	152.22	147.05	387.82	1179.43	18.76	151.97	172.77	1535867
Unit 18 Actual Emissions	42.03	159.82	151.41	277.17	1206.72	17.73	147.78	178.65	1464617
Unit 17 Cooling Tower Actual Emissions	50.16	35.11	21.07	--	--	--	--	--	--
Unit 18 Cooling Tower Actual Emissions	54.44	38.11	22.86	--	--	--	--	--	--
Total Actual Emissions	*172.43*	*385.25*	*342.40*	*664.99*	*2386.15*	*36.49*	*299.75*	*351.41*	*3000484*
Limited Emissions	*91.00*	*345.00*	*292.00*	*664.99*	*1560.00*	*36.49*	*299.75*	*280.00*	*3000484*
Units 17 & 18 and their Cooling Towers Decrease	***-81.43***	***-40.25***	***-50.40***	***0.00***	***-826.15***	***0.00***	***0.00***	***-71.41***	***0.00***

Contemporaneous Emissions Increases (ton/yr)									
	PM	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**H2SO4**	**CO2e**
2024 Peaker Project Emission Increase									
Actual Emissions	38.90	68.45	68.45	14.83	539.77	73.35	411.95	24.98	1233629

New Emissions Units Potential to Emit (ton/yr)									
	PM	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**H2SO4**	**CO2e**
2025 CCCT Project Emission									
Projected Emissions	135.24	245.62	237.83	81.01	1735.29	258.97	614.14	57.49	7072554

Net Emissions Increase (ton/yr)									
	PM	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**H2SO4**	**CO2e**
2025 CCCT Project Emissions	135.24	245.62	237.83	81.01	1735.29	258.97	614.14	57.49	7072554
Contemporaneous Increases	38.90	68.45	68.45	14.83	539.77	73.35	411.95	24.98	1233629
Contemporaneous Decreases	-149.69	-299.89	-296.43	-171.54	-2274.29	-36.21	-4622.34	-76.04	-2380454
Net Emissions Increase	**24.45**	**14.18**	**9.84**	**-75.69**	**0.77**	**296.11**	**-3596.26**	**6.42**	**5925729**
Significance Threshold (tpy)	25	15	10	40	40	40	100	7.00	75,000

2026 CCCT Project: Based on this netting analysis, the source opted to limit PM, PM10, PM2.5, NOx, and SAM in order to avoid PSD BACT analysis for these pollutants. VOC and GHGs are subject to the requirments of PSD BACT analysis.

NIPSCO LLC R.M. Schahfer Generating Station
Data for Unit 17 and Unit 18 Monthly Emissions

	Unit 17												Unit 18											
	SO2 (ton)	NOx (ton)	PMc (ton)	PMf (ton)	PM10f (ton)	PM2.5f (ton)	CO (ton)	H2SO4 (ton)	Coal (ton)	Coal (Btu/lb)	NG (cf)	Hours	SO2 (ton)	NOx (ton)	PMc (ton)	PMf (ton)	PM10f (ton)	PM2.5f (ton)	CO (ton)	H2SO4 (ton)	Coal (ton)	Coal (Btu/lb)	NG (cf)	Hours
Jan-21	19.3	66.3	7.0	1.3	0.9	0.7	8.0	9.0	31,813	10,982	524,000	308.0	46.0	89.7	9.4	3.8	2.7	1.9	10.6	12.8	42,587	10,986	22,000	422
Feb-21	99.3	210.4	21.2	1.9	1.4	1.0	24.2	27.3	96,707	10,973	1,000	672.0			0.0	0.0	0.0	0.0	0.0	0.0	0		2,000	0
Mar-21	55.4	162.1	17.3	3.5	2.5	1.8	19.7	22.2	78,812	10,973	92,000	744.0			0.0	0.0	0.0	0.0	0.0	0.0	0		1,000	0
Apr-21	41.7	131.4	13.2	3.2	2.3	1.6	15.0	16.9	60,057	10,974	13,000	490.0	15.8	28.1	2.6	0.6	0.4	0.3	3.0	3.6	11,883	10,976	724,000	144
May-21	22.4	49.6	5.6	1.0	0.7	0.5	6.4	7.2	25,415	10,974	502,000	273.0	51.1	163.9	16.9	6.4	4.6	3.3	19.3	23.2	77,071	10,980	483,000	701
Jun-21	62.6	127.6	13.3	2.5	1.7	1.3	15.2	17.1	60,718	10,980	354,000	555.0	60.8	145.6	14.8	5.8	4.1	3.0	16.9	20.3	67,594	10,981	337,000	653
Jul-21	37.6	117.2	13.5	2.3	1.6	1.2	15.4	17.4	61,602	10,992	565,000	600.0	39.6	145.3	15.8	5.1	3.6	2.6	18.0	21.6	71,946	10,992	312,000	624
Aug-21	80.8	182.3	19.9	3.3	2.4	1.7	22.7	25.6	90,778	10,959	6,000	744.0	42.0	144.5	15.8	4.2	3.0	2.2	17.9	21.5	71,582	11,007	853,000	635
Sep-21	60.1	164.2	18.2	2.8	2.0	1.4	20.7	23.3	82,657	11,005	1,142,000	720.0	43.0	162.3	18.1	5.0	3.5	2.5	20.6	24.8	82,322	11,021	264,000	720
Oct-21	47.0	130.9	14.8	2.3	1.6	1.2	16.7	18.9	66,950	11,083	264,000	627.0	34.3	167.7	18.9	7.1	5.1	3.6	21.4	25.7	85,466	11,038	1,243,091	744
Nov-21			0.0	0.0	0.0	0.0	0.0	0.0	0		0	0.0	11.4	87.8	9.3	2.8	2.0	1.4	10.5	12.7	42,089	11,048	541,639	462
Dec-21	24.3	58.3	6.6	0.7	0.5	0.4	7.5	8.4	29,906	11,070	909,000	360.0	10.8	121.5	12.6	4.5	3.2	2.3	14.3	17.1	57,030	11,046	59,000	744
Jan-22	5.6	29.1	2.9	0.4	0.3	0.2	3.3	3.9	13,228	11,059	571,000	190.0	7.1	107.1	11.3	4.2	3.0	2.1	13.0	15.6	51,175	11,039	4,615,000	638
Feb-22	9.7	39.0	4.2	0.7	0.5	0.4	4.8	5.6	19,100	11,051	1,468,000	284.0	25.0	136.3	15.9	4.4	3.1	2.2	18.1	21.9	71,841	11,032	4,175,206	672
Mar-22	27.6	114.6	12.6	2.9	2.0	1.5	14.3	16.7	57,127	11,042	861	744.0	30.4	116.0	13.4	5.6	3.9	2.8	15.2	18.5	60,786	11,032	46,000	600
Apr-22	0.6	4.5	0.4	0.1	0.1	0.0	0.4	0.5	1,578	11,038	604,024	22.0	11.4	16.8	1.7	0.2	0.2	0.1	2.0	2.3	7,693	11,031	902,000	107
May-22	65.2	112.5	12.9	2.7	1.9	1.4	14.7	17.1	58,630	11,025	492,000	566.0	31.4	156.8	16.7	5.4	3.8	2.7	19.0	23.1	75,914	11,021	386,833	709
Jun-22	20.3	94.9	11.0	2.3	1.7	1.2	12.5	14.6	50,073	11,015	336,928	531.0	19.2	158.8	16.3	5.6	4.0	2.8	18.6	22.6	74,218	11,014	348,000	716
Jul-22	15.1	65.0	8.1	1.4	1.0	0.7	9.2	10.8	36,948	11,020	195,000	383.0	17.9	147.7	15.7	6.1	4.4	3.1	17.8	21.7	71,330	11,022	0	744
Aug-22	34.4	142.0	18.2	4.0	2.8	2.0	20.5	24.0	82,163	11,052	1,000	744.0	25.6	104.1	11.0	3.8	2.7	1.9	12.4	15.1	49,704	11,043	553,866	429
Sep-22	26.3	111.5	13.3	2.8	2.0	1.4	15.0	17.6	60,095	11,063	17,000	502.0	9.8	42.7	4.5	0.9	0.6	0.5	5.1	6.1	20,189	11,055	2,229,973	263
Oct-22	49.6	179.4	20.1	4.5	3.2	2.3	22.7	26.6	90,836	11,062	295,000	736.0	1.3	10.6	1.2	0.3	0.2	0.2	1.3	1.6	5,384	11,055	16,000	63
Nov-22	39.5	142.3	15.5	4.4	3.1	2.3	17.5	20.4	69,914	11,062	8,000	599.0	43.6	124.0	13.3	3.4	2.4	1.7	15.1	18.3	60,167	11,057	863,000	460
Dec-22	23.9	52.3	5.7	0.8	0.6	0.4	6.5	7.6	25,877	11,063	333,000	281.0	15.1	49.0	5.3	0.9	0.7	0.5	6.0	7.3	23,883	11,060	1,248,000	277
Jan-23	17.85	101.89	13.7	2.0	1.4	1.0	15.5	15.6	62,077	11,060	0	744	2.2	21.8	2.5	0.5	0.3	0.2	2.8	3.6	11,158	11,061	0	145
Feb-23	8.259	46.21	6.6	1.1	0.8	0.6	7.5	7.5	29,818	11,052	10,000	358	5.3	54.9	6.3	1.2	0.8	0.6	7.1	9.1	28,403	11,056	354,000	352
Mar-23	23.047	103.65	11.1	1.6	1.2	0.8	12.6	12.7	50,424	11,037	220,000	584	32.0	119.0	15.0	4.2	3.0	2.2	17.0	21.7	68,054	11,039	85,000	577
Apr-23	8.662	31.57	3.7	0.6	0.4	0.3	4.2	4.2	16,599	11,025	12,000	146	28.1	74.7	8.5	2.0	1.4	1.0	9.7	12.3	38,410	11,021	1,693,364	368
May-23	8.122	10.97	1.3	0.1	0.0	0.0	1.5	1.5	6,090	11,020	258,000	86	21.5	58.7	9.1	1.8	1.3	0.9	10.4	13.3	41,477	11,010	507,000	473
Jun-23	8.649	13.10	1.9	0.1	0.0	0.0	2.2	2.2	8,713	11,017	307,000	104	8.1	32.0	5.5	1.0	0.7	0.5	6.2	7.9	24,857	11,005	475,000	310
Jul-23	35.115	70.72	10.8	0.25	0.2	0.1	12.3	12.4	49153.5	11019.31	188000	509	27.697	50.946	9.4	0.512178	0.4	0.3	10.7	13.7	42776.05	11009.206	491000	463
Aug-23	27.683	59.29	9.2	0.46	0.3	0.2	10.4	10.5	41560.1	11027.866	247000	408	20.111	40.973	7.2	0.6977807	0.5	0.4	8.1	10.4	32517.2	11019.362	484000	363
Sep-23	26.484	77.13	10.2	0.46	0.3	0.2	11.6	11.7	46339.42	11042.517	188000	419	25.248	21.32	3.7	0.1771743	0.1	0.1	4.3	5.4	16978.7	11029.638	570398	175
Oct-23	23.561	58.11	7.5	0.02	0.0	0.0	8.5	8.5	33851.35	11053.794	393000	304	41.474	68.391	10.7	2.122488	1.5	1.1	12.2	15.5	48412.45	11042.938	1221196	409
Nov-23	14.447	43.37	5.6	0.44	0.3	0.2	6.3	6.4	25245.2	11061.854	224000	209	26.219	35.489	6.3	1.2001615	0.9	0.6	7.2	9.1	28610.25	11056.34	267000	331
Dec-23	24.502	146.95	20.0	1.41	1.0	0.7	22.6	22.7	90302.3	11076.26	20801	744			0.0	0	0.0	0.0	0.0	0.0	0		0	0
Jan-24	53.501	185.35	23.1	1.49	1.1	0.8	26.1	28.8	104247.9	11073.81	0	744	43.215	53.894	8.2	1.9348696	1.4	1.0	9.4	7.2	36998.65	11061.917	3490730	373
Feb-24	10.017	62.40	9.4	1.15	0.8	0.6	10.6	11.7	42490.5	11058.767	12000	442	0.092	0.174	0.0	0.018952	0.0	0.0	0.0	0.0	13.45	11063	649759	23
Mar-24			0.0	0	0.0	0.0	0.0	0.0	0		0	0	7.566	31.331	5.2	1.0862453	0.8	0.6	5.7	4.4	22877.85	11388.762	644000	305
Apr-24	2.36	15.87	2.4	0.25	0.2	0.1	2.7	3.0	10748.25	11049.38	166000	152			0.0	0	0.0	0.0	0.0	0.0	0		0	0
May-24	9.63	29.27	4.9	0.82	0.6	0.4	5.5	6.1	22018.95	11045.384	17000	241	36.402	74.418	13.6	3.130548	2.2	1.6	14.9	11.6	59555.25	11436.216	246076	624
Jun-24	3.58	6.25	0.9	0.07	0.1	0.0	1.1	1.1	4141.3	11042.241	511000	83	28.737	92.186	16.5	3.6784082	2.6	1.9	18.5	14.3	73820	11194.171	8000	720
Jul-24	32.17	105.76	14.9	2.06	1.5	1.1	16.8	18.6	67300.1	11040.344	207000	705	27.926	116.727	18.8	4.3570847	3.1	2.2	21.2	16.5	84980.95	11089.342	5000	744
Aug-24	47.56	87.71	12.0	1.69	1.2	0.9	13.6	15.0	54381.2	11050.787	179000	521	7.323	37.674	5.8	1.4247896	1.0	0.7	6.6	5.1	26265.65	11065.361	261000	237
Sep-24	13.69	69.59	9.8	0.96	0.7	0.5	11.1	12.3	44398.27	11071.554	93000	401	10.046	45.534	7.6	1.9188415	1.4	1.0	8.6	6.7	34393.7	11073.149	328000	355
Oct-24	4.16	35.73	6.2	0.61	0.4	0.3	7.0	7.7	28000.95	11086.505	4000	289	7.033	74.647	13.1	2.4026999	1.7	1.2	14.8	11.5	59162.25	11089.79	198960	678
Nov-24	21.72	92.44	12.4	0.73	0.5	0.4	14.0	15.5	56006.1	11086.965	121000	515	3.205	33.032	6.9	1.2975169	0.9	0.7	7.8	6.0	31072.4	11096.401	240000	381
Dec-24	25.11	101.40	12.8	0.75	0.5	0.4	14.5	16.0	57804.55	11062.132	156000	562			0.0	0	0.0	0.0	0.0	0.0	0		0	0
Jan-25	17.89	90.57	12.1	0.42	0.3	0.2	13.7		54964.75	11026.791	174000	507	16.221	80.696	15.6	2.069798	1.5	1.1	17.6		70368.2	11055.226	311000	640
Feb-25	11.10	91.64	14.0	0.84	0.6	0.4	15.9		63623.85	10998.319	4000	672	4.988	11.64	1.7	0.2036122	0.1	0.1	2.0		7876.4	11025.57	338000	86
Mar-25	22.38	80.29	11.0	0.44	0.3	0.2	12.5		50152.75	10984.558	0	505			0.0	0	0.0	0.0	0.0				0	0
Apr-25	18.62	86.94	12.8	0.83	0.6	0.4	14.6		58298.65	10979.013	149415	600			0.0	0	0.0	0.0	0.0				0	0
May-25	20.73	44.80	6.2	0.18	0.1	0.1	7.0		27993.45	10985.79	300000	316			0.0	0	0.0	0.0	0.0				0	0
Jun-25	34.32	122.60	17.0	1.18	0.8	0.6	19.3		77100.8	10994.554	2000	720	5.492	25.798	4.2	0.6576039	0.5	0.3	4.8		18960.8	11020.074	1428636	218
Jul-25	42.67	103.44	14.8	1.50	1.1	0.8	16.9		67495.25	10979.494	184000	572	15.869	46.079	6.9	2.0129112	1.4	1.0	7.8		31389.4	11005.761	1000	213
Aug-25	13.88	45.55	7.3	0.64	0.5	0.3	8.3		33332	10973.339	145000	375			0.0	0	0.0	0.0	0.0				0	0
Sep-25	38.73	77.60	12.2	1.38	1.0	0.7	13.9		55597.65	10986.352	187000	540			0.0	0	0.0	0.0	0.0				0	0
Oct-25	19.69	102.74	14.9	1.52	1.1	0.8	16.9		67765.1	11009.8	8000	672			0.0	0	0.0	0.0	0.0				6000	0
Nov-25	12.48	55.12	6.6	0.60	0.4	0.3	7.5		29859.8	11029.172	675209	331			0.0	0	0.0	0.0	0.0				158000	0
Dec-25	23.37	126.04	16.4	0.78	0.6	0.4	18.6		74240.35	11034.7	264000	544			0.0	0	0.0	0.0	0.0				0	0
												24-month period												
Jan 2021 - Dec 2022	434.09	1,243.74	137.84	25.91	156.23	151.05	156.56	179.33					296.40	1,213.22	130.28	43.08	160.87	152.25	148.16	178.73				
Feb 2021 - Jan 2023	433.34	1,261.53	141.21	26.22	159.83	154.58	160.33	182.65					274.51	1,179.27	126.84	41.43	156.25	147.97	144.23	174.11				
Mar 2021 - Feb 2023	387.82	1,179.43	133.89	25.80	152.22	147.05	151.97	172.77					277.17	1,206.72	129.98	42.03	159.82	151.41	147.78	178.65				
Apr 2021 - Mar 2023	371.66	1,150.21	130.81	24.86	148.46	143.49	148.42	168.00					293.17	1,266.22	137.49	44.15	168.83	160.01	156.29	189.52				
May 2021 - Apr 2023	355.16	1,100.27	126.05	23.56	142.78	138.07	142.99	161.62					299.29	1,289.51	140.42	44.86	172.28	163.30	159.63	193.87				
Jun 2021 - May 2023	348.01	1,080.98	123.93	23.10	140.34	135.72	140.57	158.80					284.46	1,236.88	136.53	42.57	166.75	158.24	155.18	188.91				
Jul 2021 - Jun 2023	321.04	1,023.74	118.23	21.90	133.78	129.40	134.07	151.34					258.10	1,180.07	131.84	40.16	160.36	152.32	149.84	182.71				
Aug 2021 - Jul 2023	319.81	1,000.53	116.87	20.88	131.69	127.52	132.50	148.84					252.14	1,132.91	128.64	37.87	155.53	147.95	146.20	178.73				
Sep 2021 - Aug 2023	293.27	939.02	111.51	19.43	125.31	121.42	126.35	141.26					241.21	1,081.17	124.34	36.11	149.98	142.76	141.31	173.16				
Oct 2021 - Sep 2023	276.45	895.50	107.53	18.25	120.49	116.84	121.80	135.44					232.35	1,010.69	117.14	33.71	141.08	134.34	133.15	163.50				
Nov 2021 - Oct 2023	264.72	859.09	103.85	17.12	116.00	112.58	117.66	130.26					235.94	961.03	113.06	31.20	135.21	128.97	128.51	158.39				
Dec 2021 - Nov 2023	271.94	880.77	106.64	17.34	118.95	115.49	120.82	133.44					243.34	934.87	111.57	30.40	133.15	127.07	126.82	156.63				
Jan 2022 - Dec 2023	272.03	925.08	113.33	17.70	125.90	122.36	128.35	140.58					237.92	874.10	105.27	28.13	125.24	119.62	119.69	148.06				
Feb 2022 - Jan 2024	295.96	1,003.19	123.41	18.26	136.38	132.73	139.72	153.04					255.98	847.50	103.71	27.00	122.88	117.48	117.90	143.86				
Mar 2022 - Feb 2024	296.14	1,014.89	126.00	18.47	139.11	135.42	142.61	156.12					243.50	779.42	95.78	24.81	113.40	108.44	108.85	132.93				
Apr 2022 - Mar 2024	282.32	957.57	119.69	17.04	131.79	128.38	135.47	147.76					232.09	737.06	91.68	22.57	107.71	103.20	104.12	125.90				
May 2022 - Apr 2024	283.23	963.24	120.70	17.13	132.86	129.44	136.61	149.02					226.39	728.64	90.83	22.46	106.78	102.29	103.14	124.73				
Jun 2022 - May 2024	255.46	921.62	116.67	16.21	128.18	124.94	132.02	143.49					228.88	687.45	89.28	21.34	104.43	100.16	101.09	118.97				
Jul 2022 - Jun 2024	247.08	877.32	111.61	15.08	122.32	119.30	126.28	136.74					233.64	654.13	89.37	20.40	103.85	99.77	101.04	114.85				
Aug 2022 - Jul 2024	255.64	897.72	114.97	15.40	125.90	122.82	130.08	140.63					238.65	638.66	90.93	19.51	104.78	100.88	102.74	112.25				
Sep 2022 - Aug 2024	262.22	870.56	111.90	14.26	122.03	119.18	126.61	136.12					229.51	605.45	88.34	18.34	101.37	97.70	99.81	107.24				
Oct 2022 - Sep 2024	255.93	849.60	110.17	13.36	119.65	116.98	124.65	133.47					229.61	606.88	89.92	18.85	103.30	99.53	101.54	107.51				
Nov 2022 - Oct 2024	233.22	777.76	103.22	11.40	111.31	109.03	116.79	124.05					232.49	638.91	95.88	19.89	110.01	106.03	108.27	112.44				
Dec 2022 - Nov 2024	224.32	752.82	101.70	9.54	108.47	106.56	115.05	121.57					212.27	593.42	92.68	18.85	106.06	102.29	104.62	106.31				
Jan 2023 - Dec 2025	224.94	777.38	105.23	9.52	111.99	110.08	119.04	125.77					204.71	568.90	90.04	18.38	103.09	99.41	101.61	102.67				

Notes
PMf, NOx, and SO2 emissions based on data reported in CEMS
AP-42 Table 1.1-6 for scrubber PM10(f) = 71% of PM(f) and PM2.5(f) = 51% of PM(f)
AP-42 Table 1.1-5 PC Boiler PM(c) = 0.02 lb/MMBtu, AP-42 Table 1.4-2 NG Combustion, PM(c) = 5.7 lb/MMcf
AP-42 Table 1.1-3, PC Boiler CO = 0.5 lb/ton, AP-42 Table 1.4-1 NG Combustion, CO = 84 lb/MMcf
H2SO4 emissions based on TRI annual reporting using the EPRI March 2012 Paper
2025 H2SO4 emissions information is expected to be available later this year

NIPSCO LLC R.M. Schahfer Generating Station
Unit 17 and Unit 18 Cooling Towers Monthly Emissions

TDS	1,150.0	ppm	
Total liquid drift	1.7	lb/1000 gal	AP-42; Table 13.4-1
PM to PM10 ratio:	70%	% Drift PM	California SCAQMD CEIDARS Table
PM to PM2.5 ratio	42%	% Drift PM	California SCAQMD CEIDARS Table

	Cooling Tower for Unit 17	Cooling Tower for Unit 18
Recirc rates (1000 gal/hour)	8,700	9,600

	Unit 17 Hours	Cooling Tower Emissions (TPY) PM	PM10	PM2.5	Unit 18 Hours	Cooling Tower Emissions (TPY) PM	PM10	PM2.5
Jan-21	308	2.6	1.8	1.1	422	4.0	2.8	1.7
Feb-21	672	5.7	4.0	2.4	0	0.0	0.0	0.0
Mar-21	744	6.3	4.4	2.7	0	0.0	0.0	0.0
Apr-21	490	4.2	2.9	1.8	144	1.4	0.9	0.6
May-21	273	2.3	1.6	1.0	701	6.6	4.6	2.8
Jun-21	555	4.7	3.3	2.0	653	6.1	4.3	2.6
Jul-21	600	5.1	3.6	2.1	624	5.9	4.1	2.5
Aug-21	744	6.3	4.4	2.7	635	6.0	4.2	2.5
Sep-21	720	6.1	4.3	2.6	720	6.8	4.7	2.8
Oct-21	627	5.3	3.7	2.2	744	7.0	4.9	2.9
Nov-21	0	0.0	0.0	0.0	462	4.3	3.0	1.8
Dec-21	360	3.1	2.1	1.3	744	7.0	4.9	2.9
Jan-22	190	1.6	1.1	0.7	638	6.0	4.2	2.5
Feb-22	284	2.4	1.7	1.0	672	6.3	4.4	2.6
Mar-22	744	6.3	4.4	2.7	600	5.6	3.9	2.4
Apr-22	22	0.2	0.1	0.1	107	1.0	0.7	0.4
May-22	566	4.8	3.4	2.0	709	6.7	4.7	2.8
Jun-22	531	4.5	3.2	1.9	716	6.7	4.7	2.8
Jul-22	383	3.3	2.3	1.4	744	7.0	4.9	2.9
Aug-22	744	6.3	4.4	2.7	429	4.0	2.8	1.7
Sep-22	502	4.3	3.0	1.8	263	2.5	1.7	1.0
Oct-22	736	6.3	4.4	2.6	63	0.6	0.4	0.2
Nov-22	599	5.1	3.6	2.1	460	4.3	3.0	1.8
Dec-22	281	2.4	1.7	1.0	277	2.6	1.8	1.1
Jan-23	744	6.3	4.4	2.7	145	1.4	1.0	0.6
Feb-23	358	3.0	2.1	1.3	352	3.3	2.3	1.4
Mar-23	584	5.0	3.5	2.1	577	5.4	3.8	2.3
Apr-23	146	1.2	0.9	0.5	368	3.5	2.4	1.5
May-23	86	0.7	0.5	0.3	473	4.4	3.1	1.9
Jun-23	104	0.9	0.6	0.4	310	2.9	2.0	1.2
Jul-23	509	4.3	3.0	1.8	463	4.3	3.0	1.8
Aug-23	408	3.5	2.4	1.5	363	3.4	2.4	1.4
Sep-23	419	3.6	2.5	1.5	175	1.6	1.1	0.7
Oct-23	304	2.6	1.8	1.1	409	3.8	2.7	1.6
Nov-23	209	1.8	1.2	0.7	331	3.1	2.2	1.3
Dec-23	744	6.3	4.4	2.7	0	0.0	0.0	0.0
Jan-24	744	6.3	4.4	2.7	373	3.5	2.5	1.5
Feb-24	442	3.8	2.6	1.6	23	0.2	0.2	0.1
Mar-24	0	0.0	0.0	0.0	305	2.9	2.0	1.2
Apr-24	152	1.3	0.9	0.5	0	0.0	0.0	0.0
May-24	241	2.0	1.4	0.9	624	5.9	4.1	2.5
Jun-24	83	0.7	0.5	0.3	720	6.8	4.7	2.8
Jul-24	705	6.0	4.2	2.5	744	7.0	4.9	2.9
Aug-24	521	4.4	3.1	1.9	237	2.2	1.6	0.9
Sep-24	401	3.4	2.4	1.4	355	3.3	2.3	1.4
Oct-24	289	2.5	1.7	1.0	678	6.4	4.5	2.7
Nov-24	515	4.4	3.1	1.8	381	3.6	2.5	1.5
Dec-24	562	4.8	3.3	2.0	0	0.0	0.0	0.0
Jan-25	507	4.3	3.0	1.8	640	6.0	4.2	2.5
Feb-25	672	5.7	4.0	2.4	86	0.8	0.6	0.3
Mar-25	505	4.3	3.0	1.8	0	0.0	0.0	0.0
Apr-25	600	5.1	3.6	2.1	0	0.0	0.0	0.0
May-25	316	2.7	1.9	1.1	0	0.0	0.0	0.0
Jun-25	720	6.1	4.3	2.6	218	2.0	1.4	0.9
Jul-25	572	4.9	3.4	2.0	213	2.0	1.4	0.8
Aug-25	375	3.2	2.2	1.3	0	0.0	0.0	0.0
Sep-25	540	4.6	3.2	1.9	0	0.0	0.0	0.0
Oct-25	672	5.7	4.0	2.4	0	0.0	0.0	0.0
Nov-25	331	2.8	2.0	1.2	0	0.0	0.0	0.0
Dec-25	544	4.6	3.2	1.9	0	0.0	0.0	0.0

24-month period						
Jan 2021 - Dec 2022	49.64	34.75	20.85	54.08	37.86	22.72
Feb 2021 - Jan 2023	51.50	36.05	21.63	52.79	36.95	22.17
Mar 2021 - Feb 2023	50.16	35.11	21.07	54.44	38.11	22.86
Apr 2021 - Mar 2023	49.48	34.64	20.78	57.14	40.00	24.00
May 2021 - Apr 2023	48.02	33.61	20.17	58.19	40.74	24.44
Jun 2021 - May 2023	47.22	33.06	19.83	57.13	39.99	23.99
Jul 2021 - Jun 2023	45.31	31.71	19.03	55.52	38.86	23.32
Aug 2021 - Jul 2023	44.92	31.44	18.87	54.76	38.33	23.00
Sep 2021 - Aug 2023	43.49	30.44	18.27	53.48	37.44	22.46
Oct 2021 - Sep 2023	42.21	29.55	17.73	50.93	35.65	21.39
Nov 2021 - Oct 2023	40.84	28.59	17.15	49.36	34.55	20.73
Dec 2021 - Nov 2023	41.73	29.21	17.52	48.74	34.12	20.47
Jan 2022 - Dec 2023	43.36	30.35	18.21	45.25	31.67	19.00
Feb 2022 - Jan 2024	45.71	32.00	19.20	44.01	30.80	18.48
Mar 2022 - Feb 2024	46.39	32.47	19.48	40.96	28.67	17.20
Apr 2022 - Mar 2024	43.22	30.26	18.15	39.58	27.70	16.62
May 2022 - Apr 2024	43.78	30.64	18.39	39.07	27.35	16.41
Jun 2022 - May 2024	42.39	29.68	17.81	38.68	27.07	16.24
Jul 2022 - Jun 2024	40.49	28.34	17.01	38.69	27.09	16.25
Aug 2022 - Jul 2024	41.86	29.30	17.58	38.69	27.09	16.25
Sep 2022 - Aug 2024	40.91	28.64	17.18	37.79	26.46	15.87
Oct 2022 - Sep 2024	40.48	28.34	17.00	38.23	26.76	16.05
Nov 2022 - Oct 2024	38.58	27.01	16.20	41.11	28.78	17.27
Dec 2022 - Nov 2024	38.22	26.76	16.05	40.74	28.52	17.11
Jan 2023 - Dec 2025	39.42	27.59	16.56	39.44	27.61	16.57

Appendix A: Emissions Calculations
Unit 21A, Unit 21B, Unit 22A, Unit 22B

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Projected Operation

			HHV	
Proposed CT Units	Unit 21A, Unit 21B, Unit 22A, Unit 22B		mmBtu	Potential Throughput
Maximum Heat input per Turbine	3204	MMBtu/hr @ 4.1F, 100% load	mmscf	MMCF/yr
Output (gross)	357	MW @4.1F, 100% load	1020	27516.71
Number of Turbines:	4			
Operation Mode	Simple cycle			
CO Oxydation Catalyst	Yes			
Annual capacity factor	40.0%	NSPS TTTTa criteria for simple cycle units capacity factor restriction applicable to the turbines (40 CFR 60.5580a)		
Number of SU/SD	1	events per day		
CT operation	365	events/year		
Startup duration for CT*	0.35	hour (21 min hot start)		
Shutdown duration for CT*	0.25	hour (15 min)		
Heat input during events*	1007.0	MMBtu/event		
Oxidation Catalyst Control	50%	for VOC		
Oxidation Catalyst Control	90%	for CO		

Unlimited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Events	Normal Operation (1 Turbines)	Startup/Shutdown (1 Turbines)	Total Combined (1 turbines)	Total Combined (4 turbines)
PM*	8.05 lb/hr	8.55 lb/event	34.38 tons/yr	1.56 tons/yr	35.94 tons/yr	143.75 tons/yr
PM10	16.10 lb/hr	17.10 lb/event	68.76 tons/yr	3.12 tons/yr	71.88 tons/yr	287.50 tons/yr
PM2.5	16.10 lb/hr	17.10 lb/event	68.76 tons/yr	3.12 tons/yr	71.88 tons/yr	287.50 tons/yr
SO2	5.10 lb/hr	5.10 lb/event	21.78 tons/yr	0.93 tons/yr	22.71 tons/yr	90.84 tons/yr
NOx	195.40 lb/hr	175.00 lb/event	834.46 tons/yr	31.94 tons/yr	866.39 tons/yr	3465.57 tons/yr
VOC**	9.10 lb/hr	140.00 lb/event	38.86 tons/yr	25.55 tons/yr	64.41 tons/yr	257.65 tons/yr
CO**	15.90 lb/hr	375.00 lb/event	67.90 tons/yr	68.44 tons/yr	136.34 tons/yr	545.35 tons/yr
SAM	7.60 lb/hr	7.60 lb/event	32.46 tons/yr	1.39 tons/yr	33.84 tons/yr	135.37 tons/yr
CO2e	439621 lb/hr	439621 lb/event	1877401 tons/yr	80230.8 tons/yr	1957632 tons/yr	7830526 tons/yr

Limited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Events	Normal Operation (1 Turbines)	Startup/Shutdown (1 Turbines)	Total Combined (1 turbines)	Total Combined (4 turbines)
PM*	8.05 lb/hr	8.55 lb/event	13.75 tons/yr	1.56 tons/yr	15.31 tons/yr	61.25 tons/yr
PM10	16.10 lb/hr	17.10 lb/event	27.50 tons/yr	3.12 tons/yr	30.62 tons/yr	122.49 tons/yr
PM2.5	16.10 lb/hr	17.10 lb/event	27.50 tons/yr	3.12 tons/yr	30.62 tons/yr	122.49 tons/yr
SO2	5.10 lb/hr	5.10 lb/event	8.71 tons/yr	0.93 tons/yr	9.64 tons/yr	38.57 tons/yr
NOx	195.40 lb/hr	175.00 lb/event	333.78 tons/yr	31.94 tons/yr	365.72 tons/yr	1462.88 tons/yr
VOC**	9.10 lb/hr	140.00 lb/event	15.54 tons/yr	25.55 tons/yr	41.09 tons/yr	164.38 tons/yr
CO**	15.90 lb/hr	375.00 lb/event	27.16 tons/yr	68.44 tons/yr	95.60 tons/yr	382.39 tons/yr
SAM	7.60 lb/hr	7.60 lb/event	12.98 tons/yr	1.39 tons/yr	14.37 tons/yr	57.48 tons/yr
CO2e	439621 lb/hr	439621 lb/event	770216 tons/yr	80231 tons/yr	850447 tons/yr	3401786 tons/yr

Controlled Emissions

Pollutant	Normal Operation (1 Turbines)	Startup/Shutdown (1 Turbines)	Total Combined (1 turbines)	Total Combined (4 turbines)
PM*	34.38 tons/yr	1.56 tons/yr	35.94 tons/yr	143.75 tons/yr
PM10	68.76 tons/yr	3.12 tons/yr	71.88 tons/yr	287.50 tons/yr
PM2.5	68.76 tons/yr	3.12 tons/yr	71.88 tons/yr	287.50 tons/yr
SO2	21.78 tons/yr	0.93 tons/yr	22.71 tons/yr	90.84 tons/yr
NOx	834.46 tons/yr	31.94 tons/yr	866.39 tons/yr	3465.57 tons/yr
VOC**	19.43 tons/yr	12.78 tons/yr	32.21 tons/yr	128.82 tons/yr
CO**	6.79 tons/yr	6.84 tons/yr	13.63 tons/yr	54.54 tons/yr
SAM	32.46 tons/yr	1.39 tons/yr	33.84 tons/yr	135.37 tons/yr
CO2e	1877400.80 tons/yr	80230.80 tons/yr	1957631.60 tons/yr	7830526.40 tons/yr

Methodology:
Emission rates for all pollutants are provided by the source based on the information provided by the equipment supplier/vendor
* PM filterable is assumed as 50% of the PM10 (filterable + condensable) rate provided by the vendor
** VOC and CO emission rates are based on the use of CO oxidation catalyst controls for both simple cycle and combined cycle modes for the proposed CTs.
SAM: Sulfur Acid Mist

Unlimited PTE in Normal Operation (tons/yr) = Emission Factor (lb/hr) * Number of Turbines (4 units) * [8760 (hrs/yr) - 365 (events/yr) * (0.35 hr/event + 0.25 hr/event)] * 1 ton/ 2000 lbs
Limited PTE in Normal Operation (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.0%)
PTE in SU/SD operation (tons/yr) = Emission Factor (lb/event) * Number of event per year (365 events) * Number of turbines (4 units) * 1 ton / 2000 lbs
Total Unlimited PTE (tons/yr) = Unlimited PTE in Normal Operation (tons/yr) + PTE in SU/SD operation (tons/yr)
Total Limited PTE (tons/yr) = Limited PTE in Normal Operation (tons/yr) + Unlimited PTE in SU/SD operation (tons/yr)
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
PTE CO2e (lb/hr) = [CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (28) + N2O Potential Emission ton/yr x N2O GWP (265)] x Heat Input Capacity of the turbine.(MMbtu/hr)
* Startup/shutdown durations and heat input during starup/shutdown events for the turbines was provided by the source.

Pollutants	Emission Factors		***Unlimited HAP Emissions***		***Limited HAP Emissions***		
Acetaldehyde	4.00E-05	lb/MMBtu	2.25	tons/yr	0.90	tons/yr	
Acroliein	6.40E-06	lb/MMBtu	0.36	tons/yr	0.14	tons/yr	
Benzene	1.20E-05	lb/MMBtu	0.67	tons/yr	0.27	tons/yr	
Ethylbenzene	3.20E-05	lb/MMBtu	1.80	tons/yr	0.72	tons/yr	
Formaldehyde	0.77	lb/hr	13.49	tons/yr	5.40	tons/yr	
Hexane	2.50E-04	lb/MMBtu	14.03	tons/yr	5.61	tons/yr	
Napthalene	1.30E-06	lb/MMBtu	0.07	tons/yr	0.03	tons/yr	
PAH	2.20E-06	lb/MMBtu	0.12	tons/yr	0.05	tons/yr	
Toluene	1.30E-04	lb/MMBtu	7.30	tons/yr	2.92	tons/yr	
Xylene	6.40E-05	lb/MMBtu	3.59	tons/yr	1.44	tons/yr	
	Total HAP Emissions		**43.68**	**tons/yr**	17.47	**tons/yr**	
	Single Worst HAP Emission		**14.03**	**tons/yr**	5.61	**tons/yr**	Hexane

Methodology
Emission Factors from AP-42, Chapter 3.1 (Stationary Gas Turbines) - Table 3.1-3
Hexane EF from BAAQMD TAC Emission Factor Guidelines, 8/2020
Unlimited PTE (tons/yr) = Maximum Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * Number of Turbines (4 units) * 8760 (hr/yr) * (1 ton / 2000 lbs)
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.0%)
Controlled PTE (tons/yr) = Unlimited PTE (tons/yr) * (1 - Control Efficiency)

Appendix A: Emissions Calculations
Unit 21A, Unit 21B, Unit 22A, Unit 22B

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Projected Operation

			HHV mmBtu / mmscf	Potential Throughput MMCF/yr
Proposed CT Units		Unit 21A, Unit 21B, Unit 22A, Unit 22B		
Maximum Heat input per Turbine	3400	MMBtu/hr @ 4.1F, 100% load	1020	29200
Heat Input for duct burner (DB)	987	MMBtu/hr @ 4.1F, 100% load		8477
Output (gross)	1335	MW @4.1F, 100% load for 2x1 block with DB		
Number of Turbines:	4	2x1 block configuration		
Operation Mode		Combined cycle and duct burner (DB)		
CO Oxydation Catalyst	Yes			
Annual Operation excluding SU/SD and DB	74.0%	Subtracts 1 SUSD/day and operation with Duct Burners		
Number of SU/SD	1	events per day		
CT operation	365	events/year		
Startup duration for CT*	0.50	hour (30 min hot start)		
Shutdown duration for CT*	0.25	hour (15 min)		
Heat input during events*	1007	MMBtu/event		
Annual operation using DBs	2000	hours/year (assumption) = 23%		
Oxidation Catalyst Control	50%	for VOC		
Oxidation Catalyst Control	90%	for CO		

Unlimited Emissions

Pollutant	Emission Rate in Normal Operation without DB	Emission Rate in Normal Operation with DB	Emission Rate in Startup/Shutdown Events	Normal Operation (1 Turbines)	Startup/Shutdown (1 Turbines)	Total Combined (1 turbines)	Total Combined (4 turbines)
PM*	6.55 lb/hr	12.25 lb/hr	17.10 lb/event	51.98 tons/yr	3.12 tons/yr	55.10 tons/yr	220.40 tons/yr
PM10	13.10 lb/hr	24.50 lb/hr	17.10 lb/event	103.96 tons/yr	3.12 tons/yr	107.08 tons/yr	428.31 tons/yr
PM2.5	13.10 lb/hr	24.50 lb/hr	17.10 lb/event	103.96 tons/yr	3.12 tons/yr	107.08 tons/yr	428.31 tons/yr
SO2	5.40 lb/hr	6.90 lb/hr	5.40 lb/event	29.28 tons/yr	0.99 tons/yr	30.26 tons/yr	121.05 tons/yr
NOx	144.83 lb/hr	34.76 lb/hr	175.00 lb/event	614.53 tons/yr	31.94 tons/yr	646.47 tons/yr	2585.88 tons/yr
VOC**	9.60 lb/hr	15.40 lb/hr	140.00 lb/event	65.34 tons/yr	25.55 tons/yr	90.89 tons/yr	363.58 tons/yr
CO**	16.80 lb/hr	21.50 lb/hr	375.00 lb/event	91.23 tons/yr	68.44 tons/yr	159.66 tons/yr	638.66 tons/yr
SAM	2.70 lb/hr	4.50 lb/hr	2.70 lb/event	19.09 tons/yr	0.49 tons/yr	19.59 tons/yr	78.35 tons/yr
CO2e	466514 lb/hr	601940 lb/hr	466514 lb/event	2554107.81 tons/yr	85139 tons/yr	2639247 tons/yr	10556986 tons/yr

Limited Emissions

Pollutant	Emission Rate in Normal Operation without DB	Emission Rate in Normal Operation with DB	Emission Rate in Startup/Shutdown Events	Normal Operation (1 Turbines)	Startup/Shutdown (1 Turbines)	Total Combined (1 turbines)	Total Combined (4 turbines)
PM*	6.55 lb/hr	12.25 lb/hr	17.10 lb/event	26.94 tons/yr	3.12 tons/yr	30.06 tons/yr	120.25 tons/yr
PM10	13.10 lb/hr	24.50 lb/hr	17.10 lb/event	53.88 tons/yr	3.12 tons/yr	57.01 tons/yr	228.02 tons/yr
PM2.5	13.10 lb/hr	24.50 lb/hr	17.10 lb/event	53.88 tons/yr	3.12 tons/yr	57.01 tons/yr	228.02 tons/yr
SO2	5.40 lb/hr	6.90 lb/hr	5.40 lb/event	19.01 tons/yr	0.99 tons/yr	20.00 tons/yr	79.99 tons/yr
NOx	144.83 lb/hr	34.76 lb/hr	175.00 lb/event	359.63 tons/yr	31.94 tons/yr	391.57 tons/yr	1566.28 tons/yr
VOC**	9.60 lb/hr	15.40 lb/hr	140.00 lb/event	36.93 tons/yr	25.55 tons/yr	62.48 tons/yr	249.94 tons/yr
CO**	16.80 lb/hr	21.50 lb/hr	375.00 lb/event	59.18 tons/yr	68.44 tons/yr	127.62 tons/yr	510.49 tons/yr
SAM	2.70 lb/hr	4.50 lb/hr	2.70 lb/event	10.56 tons/yr	0.49 tons/yr	11.05 tons/yr	44.20 tons/yr
CO2e	466514 lb/hr	601940 lb/hr	466514 lb/event	1648389 tons/yr	85139 tons/yr	1733528 tons/yr	6934113 tons/yr

Controlled Emissions

Pollutant	Normal Operation (1 Turbines)	Startup/Shutdown (1 Turbines)	Total Combined (1 turbines)	Total Combined (4 turbines)
PM*	51.98 tons/yr	3.12 tons/yr	55.10 tons/yr	220.40 tons/yr
PM10	103.96 tons/yr	3.12 tons/yr	107.08 tons/yr	428.31 tons/yr
PM2.5	103.96 tons/yr	3.12 tons/yr	107.08 tons/yr	428.31 tons/yr
SO2	29.28 tons/yr	0.99 tons/yr	30.26 tons/yr	121.05 tons/yr
NOx	614.53 tons/yr	31.94 tons/yr	646.47 tons/yr	2585.88 tons/yr
VOC**	32.67 tons/yr	12.78 tons/yr	45.45 tons/yr	181.79 tons/yr
CO**	9.12 tons/yr	6.84 tons/yr	15.97 tons/yr	63.87 tons/yr
SAM	19.09 tons/yr	0.49 tons/yr	19.59 tons/yr	78.35 tons/yr
CO2e	2554107.81 tons/yr	85138.81 tons/yr	2639246.61 tons/yr	10556986.45 tons/yr

Methodology:
Emission rates for all pollutants are provided by the source based on the information provided by the equipment supplier/vendor
* PM filterable is assumed as 50% of the PM10 (filterable + condensable) rate provided by the vendor
** VOC and CO emission rates are based on the use of CO oxidation catalyst controls for both simple cycle and combined cycle modes for the proposed CTs.
SAM: Sulfure Acid Mist

Unlimited PTE in Normal Operation (tons/yr) = [(Emission Factor w/o DB (lb/hr) + Emission Factor with DB (lb/hr)] * [Number of Turbines (4 units)] * [8760 (hrs/yr) - 365 (events/yr) * (0.35 hr/event + 0.25 hr/event)] * 1 ton/ 2000 lbs
Limited PTE in Normal Operation (tons/yr) = Emission Factor w/o DB (lb/hr) * (Annual Capacity Factor (74.0%) + Annual Operation using DB) + (Emission Factor with DB (lb/hr) + Annual Operation using DB) * [Number of Turbines (4 units)] * [8760 (hrs/yr) * 1 ton / 2000 lbs]
PTE in SU/SD Operation (tons/yr) = Emission Factor (lb/event) * Number of Event per Year (365 events) * Number of Turbines (4 units) * 1 ton / 2000 lbs
Total Unlimited PTE (tons/yr) = Unlimited PTE in Normal Operation (tons/yr) + PTE in SU/SD Operation (tons/yr)
Total Limited PTE (tons/yr) = Limited PTE in Normal Operation (tons/yr) + PTE in SU/SD Operation (tons/yr)
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
PTE CO2e (lb/hr) = [CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (28) + N2O Potential Emission ton/yr x N2O GWP (265)] x Heat Input Capacity of the turbine.(MMbtu/hr)
* Startup/shutdown durations and heat input during starup/shutdown events for the turbines was provided by the source.

Pollutants	**Emission Factors**		***Unlimited HAP Emissions***		***Limited HAP Emissions***		
HAPs Emission from CT without Duct Burner							
Acetaldehyde	4.00E-05	lb/MMBtu	2.38	tons/yr	1.92	tons/yr	
Acroliein	6.40E-06	lb/MMBtu	0.38	tons/yr	0.31	tons/yr	
Benzene	1.20E-05	lb/MMBtu	0.71	tons/yr	0.58	tons/yr	
Ethylbenzene	3.20E-05	lb/MMBtu	1.91	tons/yr	1.54	tons/yr	
Formaledyhyde	0.77	lb/hr	13.49	tons/yr	9.99	tons/yr	
Hexane	2.50E-04	lb/MMBtu	14.89	tons/yr	12.01	tons/yr	
Napthalene	1.30E-06	lb/MMBtu	0.08	tons/yr	0.06	tons/yr	
PAH	2.20E-06	lb/MMBtu	0.13	tons/yr	0.11	tons/yr	
Toluene	1.30E-04	lb/MMBtu	7.74	tons/yr	6.25	tons/yr	
Xylene	6.40E-05	lb/MMBtu	3.81	tons/yr	3.08	tons/yr	
HAPs Emission from Duct Burner							
Arsenic compounds	2.0E-04	lb/MMcf	3.39E-03	tons/yr	0.00E+00	tons/yr	
Beryllium compounds	1.2E-05	lb/MMcf	2.03E-04	tons/yr	0.00E+00	tons/yr	
Cadmium compounds	1.1E-03	lb/MMcf	1.86E-02	tons/yr	0.00E+00	tons/yr	
Chromium compounds	1.4E-03	lb/MMcf	2.37E-02	tons/yr	0.00E+00	tons/yr	
Cobalt compounds	8.4E-05	lb/MMcf	1.42E-03	tons/yr	0.00E+00	tons/yr	
Lead compounds	5.0E-04	lb/MMcf	8.48E-03	tons/yr	0.00E+00	tons/yr	
Manganese compounds	3.8E-04	lb/MMcf	6.44E-03	tons/yr	0.00E+00	tons/yr	
Mercury compounds	2.6E-04	lb/MMcf	4.41E-03	tons/yr	0.00E+00	tons/yr	
Nickel compounds	2.1E-03	lb/MMcf	3.56E-02	tons/yr	0.00E+00	tons/yr	
Selenium compounds	2.4E-05	lb/MMcf	4.07E-04	tons/yr	0.00E+00	tons/yr	
Benzene	2.1E-03	lb/MMcf	3.56E-02	tons/yr	0.00E+00	tons/yr	
Dichlorobenzene	1.2E-03	lb/MMcf	2.03E-02	tons/yr	0.00E+00	tons/yr	
Formaldehyde	7.5E-02	lb/MMcf	1.27	tons/yr	0.00	tons/yr	
Hexane	1.8	lb/hr	31.54	tons/yr	0.00	tons/yr	
Naphthalene	6.4E-04	lb/MMcf	1.09E-02	tons/yr	0.00E+00	tons/yr	
POM	7.0E-04	lb/MMcf	1.18E-02	tons/yr	0.00E+00	tons/yr	
Toluene	3.4E-03	lb/MMcf	5.76E-02	tons/yr	0.00E+00	tons/yr	
	Total HAP Emissions		**78.58**	**tons/yr**	**35.84**	**tons/yr**	
	Single Worst HAP Emission		**46.43**	**tons/yr**	**9.99**	**tons/yr**	Hexane

Methodology
Emission Factors from AP-42, Chapter 3.1 (Stationary Gas Turbines) - Table 3.1-3
Hexane EF from BAAQMD TAC Emission Factor Guidelines, 8/2020
Formaldehyde emissions rate are provided by the source based on the the equipment vendor specifications.

HAPs Emissions from CT without Duct Burner
Unlimited PTE (tons/yr) = Maximum Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * Number of Turbines (4 units) * 8760 (hr/yr) * (1 ton / 2000 lbs)
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Annual capacity factor (74.0%)
Controlled PTE (tons/yr) = Unlimited PTE (tons/yr) * (1 - Control Efficiency)

HAPs Emissions from Duct Burner
Unlimited PTE (tons/yr) = Maximum Heat Input Capacity (MMcf/yr) * Emission Factor (lb/MMBtu) * Number of Turbines (4 units) * (1 ton / 2000 lbs)
Limited PTE (tons/yr) = Limited Maximum Heat Input Capacity (MMcf/yr) * Emission Factor (lb/MMBtu) * Number of Turbines (4 units) * (1 ton / 2000 lbs)
Controlled PTE (tons/yr) = Unlimited PTE (tons/yr) * (1 - Control Efficiency)

Appendix A: Emission Calculations
Natural Gas Combustion (> 100 MMBtu/hr)
Auxiliary Boilers (AUX1 and AUX2)

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Unit ID	MMBtu/hr
AUX1	115
AUX2	115
Total	**230**

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr
230.0	1020	1975.3

	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	1.88	7.51	7.51	0.59	138.27	5.43	82.96

*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
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)
Potential Throughput (MMCF/yr) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Potential Emission (tons/yr) = Potential Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	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	2.07E-03	1.19E-03	0.07	1.78	3.36E-03

	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	4.94E-04	1.09E-03	1.38E-03	3.75E-04	2.07E-03

Potential Emission of Combined HAPs (tons/yr)	**1.86**	
Potential Emission of Highest Single HAP (tons/yr)	**1.78**	**Hexane**

Methodology
Methodology is the same above.
The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Greenhouse Gases (GHGs)

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	0.64
Potential Emission in tons/yr	118,518	2.3	0.6
Summed Potential Emissions in tons/yr	118,521		
CO2e Total in tons/yr	118,749		

Methodology
The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Emission (tons/yr) = Potential Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (28) + N2O Potential Emission ton/yr x N2O GWP (265).

Appendix A: Emissions Calculations
Natural Gas Combustion (≤ 100 MMBtu/hr)
Natural Gas Dew Point Heater

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr
28.0	1020	240.5

	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	0.23	0.91	0.91	0.07	12.02	0.66	10.10

*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
Potential Emission (tons/yr) = Potential Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics				
	Benzene	Dichlorobenze	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	2.5E-04	1.4E-04	9.0E-03	2.2E-01	4.1E-04

	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	6.0E-05	1.3E-04	1.7E-04	4.6E-05	2.5E-04

Potential Emission of Combined HAPs (tons/yr)	**2.3E-01**	
Potential Emission of Highest Single HAP (tons/yr)	**2.2E-01**	**Hexane**

Methodology
Methodology is the same as above.
The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Greenhouse Gases (GHGs)

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	2.2
Potential Emission in tons/yr	14,428	0.28	0.26
Summed Potential Emissions in tons/yr	14,429		
CO2e Total in tons/yr	14,506		

Methodology
The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Emission (tons/yr) = Potential Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

Appendix A: Emission Calculations
Cooling Towers (CTH1 and CTH2)

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

	CTH1	CTH2
Circulation water flow rate (gal/min)	280,000	280,000
TDS circulating water (ppmv)	2,000	2,000
Total drift loss (%)	0.001%	0.001%
Operating time (hrs/yr)	8,760	8,760

Particle size multiplier*	PM	100%
	PM10	63.50%
	PM2.5	0.21%

*PM10 and PM2.5 ratio calculated using the approach from Joel Reisman and Gordon Frisbie 2002 Publication, Calculating Realistic PM10 Emissions from Cooling Towers.

	PTE (lbs/hr)			PTE (tons/yr)		
Emission Unit	**PM**	**PM10**	**PM2.5**	**PM**	**PM10**	**PM2.5**
Mechanical Draft Cooling Tower (CTH1)	1.40	0.89	0.00	6.14	3.90	0.01
Mechanical Draft Cooling Tower (CTH2)	1.40	0.89	0.00	6.14	3.90	0.01
Total	**2.80**	**1.78**	**0.01**	**12.27**	**7.79**	**0.03**

Methodology

$$E = \dot{V} \times \frac{TDS}{10^6} \times \frac{\eta_{Drift}}{100} \times \rho_{H_2O} \times 60 \times OH \qquad (2)$$

Where:

E = Annual Emissions in pounds per year (lb/yr)
$\dot{V}$ = Cooling tower circulating water rate (**gal/min**)
TDS = Concentration of total dissolved solids in circulating water (PPM by weight)
η_{Drift} = Drift loss of circulating water (%).
ρ_{H_2O} = Density of water: 8.34 lb/gal
60 = Conversion from minutes to hours
OH = Annual Operating hours (hours/year)

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (>600 HP)
Diesel Emergency Generators EDGCC1 and EDGCC2

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

The engine has been certified to comply with the emission standards in 40 CFR 60, Subpart IIII, New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines. Therefore, the NSPS Subpart IIII emission standards for PM, NOx, VOC, and CO are used as the emission factors to determine the potential to emit (PTE).

Emissions calculated based on output rating (hp)

Emission Unit ID	Horsepower (hp)
EDGCC1	3,353
EDGCC2	3,353
Total	**6,706**

NSPS Subpart IIII Emission Standards based on a: 2007 model year emergency engine

Output Horsepower Rating (hp)	6706.0	
Output Horsepower Rating (kw)	5001	
Maximum Hours Operated per Year	500	(emergency generator or fire pump)
Potential Throughput (hp-hr/yr)	3,353,000	
Potential Throughput (kw-hr/yr)	2,500,332	
Sulfur Content (S) of Fuel (% by weight)	0.0015	(ultra low sulfur diesel with sulfur content of 15 ppm pursuant to 40 CFR 60.4207(b))

	Pollutant							
	PM	PM10*	direct PM2.5*	SO2 *(.00809S)*	NOx[1]	VOC	CO	H2SO4
AP-42 Emission Factor in lb/hp-hr		4.01E-04	3.89E-04	1.21E-05		6.42E-04		3%
40 CFR 60 (NSPS), Subpart IIII, Emission Standard (g/kw-hr)	0.20				6.40		3.50	
Potential Emissions ton/year								
Based on AP-42 lb/hr Emission Factor		0.67	0.65	0.02				
Based on g/kw-hr Emission Factor	0.55				17.64	1.08	9.65	
Potential Emission in tons/yr	**0.55**	**0.67**	**0.65**	**0.02**	**17.64**	**1.08**	**9.65**	6.10E-04

*The PM10 and PM2.5 emission factors for are from AP-42 Table 3.4-2. The PM10 emission factor is the sum of filterable PM10 and condensable particulate. The PM2.5 emission factor is the sum of filterable particulate less than 3 um and condensable particulate. Emission factors in lb/hp-hr were calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Tables 3.3-1 and 3.4-1). The VOC emission factor was estimated based on the 91%
Note 1: For engines that have a combined NOx + NMHC emission standard under NSPS Subpart IIII, the individual NOx emission standards were estimated from the combined NOx + NMHC emission standard assuming 80% NOx based on the equation provided in 40 CFR 1039.740(c).
SAM emission factor is based on engineering estimate

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs**
Emission Factor in lb/hp-hr***	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	9.11E-03	3.30E-03	2.26E-03	9.26E-04	2.96E-04	9.25E-05	2.49E-03

**PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
***Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Tables 3.3-1 and 3.4-1).

Potential Emission of Total HAPs (tons/yr)	**1.85E-02**	
Potential Emission of Highest Single HAP (tons/yr)	**9.11E-03**	**Benzene**

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Greenhouse Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.16E+00	6.35E-05	9.30E-06
Potential Emission in tons/yr	1.94E+03	1.06E-01	1.56E-02

Summed Potential Emissions in tons/yr	**1945**
CO2e Total in tons/yr	**1952**

Methodology
CO2 Emission Factor is from AP 42 (Supplement B 10/96) Table 3.4-1.
CH4 and N2O Emission Factors are from 40 CFR 98 Subpart C Table C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Emission (tons/yr) = [Potential Throughput (MMBtu/yr)] * [Emission Factor (lb/MMBtu)] / [2,000 lb/ton]
CO2e (tons/yr) based on 11/29/2013 federal GWPs= CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (28) + N2O Potential Emission ton/yr x N2O GWP (265).

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (<=600 HP)
Diesel Fire Pumps FPCC1 and FPCC2

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

The engine has been certified to comply with the emission standards in 40 CFR 60, Subpart IIII, New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines. Therefore, the NSPS Subpart IIII emission standards for PM, NOx, VOC, and CO are used as the emission factors to determine the potential to emit (PTE).

Emissions calculated based on output rating (hp)

Emission Unit ID	Horsepower (hp)
FPCC1	327
FPCC2	327
Total	**654**

NSPS Subpart IIII Emission Standards based on a: 2009 model year emergency engine

Output Horsepower Rating (hp)	654.0	
Output Horsepower Rating (kw)	487.7	
Maximum Hours Operated per Year	500	(emergency generator or fire pump)
Potential Throughput (hp-hr/yr)	327,000	
Potential Throughput (kw-hr/yr)	243,844	
Sulfur Content (S) of Fuel (% by weight)	0.0015	(ultra low sulfur diesel with sulfur content of 15 ppm pursuant to 40 CFR 60.4207(b))

	Pollutant							
	PM	PM10*	direct PM2.5*	SO2	NOx[1]	VOC	CO	H2SO4
AP-42 Emission Factor in lb/hp-hr		0.0022	0.0022	2.05E-03		0.0025		3%
40 CFR 60 (NSPS), Subpart IIII, Emission Standard (g/kw-hr)	0.20				4.00		3.5	
Potential Emissions ton/year								
Based on AP-42 lb/hr Emission Factor		0.36	0.36	0.335				
Based on g/kw-hr Emission Factor	0.05				1.08	6.64E-04	0.94	
Potential Emission in tons/yr	**0.05**	**0.36**	**0.36**	**0.34**	**1.08**	**6.64E-04**	**0.94**	**0.010**

*The PM10 and PM2.5 emission factors for are from AP-42 Table 3.3-1. 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.

Note 1: For engines that have a combined NOx + NMHC emission standard under NSPS Subpart IIII, the individual NOx emission standards were estimated from the combined NOx + NMHC emission standard assuming 80% NOx based on the equation provided in 40 CFR 1039.740(c).

SAM emission factor is based on engineering estimate

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
Potential Emission in tons/yr	1.07E-03	4.68E-04	3.26E-04	4.47E-05	1.35E-03	8.78E-04	1.06E-04	1.92E-04

**PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
***Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**4.43E-03**
Potential Emission of Highest Single HAP (tons/yr)	**1.35E-03** Formaldeyhde

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.3-1 and 3.3-2.
Output Horsepower Rating (kw) = Output Horsepower Rating (hp) * (0.7457 kw/hp)
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Throughput (kw-hr/yr) = [Output Horsepower Rating (kw)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] * [ton/2,000 lbs]
Potential Emission (tons/yr) = [Potential Throughput (kw-hr/yr)] * [Emission Factor (g/kw-hr)] * [lb / 453.592 g] * [ton/2,000 lbs]

Greenhouse Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.15E+00	4.63E-05	9.26E-06
Potential Emission in tons/yr	1.88E+02	7.57E-03	1.51E-03

Summed Potential Emissions in tons/yr	**188.03**
CO2e Total in tons/yr	**188.64**

Methodology
CO2 Emission Factor is from AP42 (Supplement B 10/96), Tables 3.3-1.
CH4 and N2O Emission Factors are from 40 CFR 98 Subpart C Table C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (28) + N2O Potential Emission ton/yr x N2O GWP (265).

Appendix A: Emissions Calculations
Lube Oil Tank Desmister Vents
LOV21A, LOV21B, LOV22A, LOV22B, LOV21S, LOV22S

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Vent Flow Rate	500	cfm
Oil Mist Loading (OML)	4.41E-07	lb/cf
Hours of Operation	8,760	hours/yr

	PTE (lb/hr)				PTE (tons/yr)			
Emission Unit	**PM**	**PM10**	**PM2.5**	**VOC**	**PM**	**PM10**	**PM2.5**	**VOC**
LOV21A	0.00E+00	1.32E-02	1.32E-02	1.32E-02	0.00	0.06	0.06	0.06
LOV21B	0.00E+00	1.32E-02	1.32E-02	1.32E-02	0.00	0.06	0.06	0.06
LOV22A	0.00E+00	1.32E-02	1.32E-02	1.32E-02	0.00	0.06	0.06	0.06
LOV22B	0.00E+00	1.32E-02	1.32E-02	1.32E-02	0.00	0.06	0.06	0.06
LOV21S	0.00E+00	1.32E-02	1.32E-02	1.32E-02	0.00	0.06	0.06	0.06
LOV22S	0.00E+00	1.32E-02	1.32E-02	1.32E-02	0.00	0.06	0.06	0.06
Total	**0.00**	**0.08**	**0.08**	**0.08**	**0.00**	**0.35**	**0.35**	**0.35**

Methodology
PTE (lb/hr) = Vent Flow Rate (cfm) * Oil Mist Loading (lb/cfm) * (60 min / 1 hr)
PTE (tons/yr) = PTE (lb/hr) * 8760 (hr/yr) * (1 ton / 2000 lbs)
Oil mist loading based on preliminary engineering estimate.
Conservatively assumed all particulate matter emissions are less than 2.5 micrometers in diameter.
Conservatively assumed all emissions are both VOC and particulate matter.

Appendix A: Emission Calculations
Fugitive Equipment Leaks-Circuit Breakers - CCCT Turbines

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Proposed operations: *Circuit breakers insulated with SF6*

Breaker Type	Breaker Count	Total SF6 per Component (lbs)	Leak Rate (% per year)	SF6 emissions (ton/yr)	CO2e Emissions (ton/yr)
500 kV		1,437	0.5%	0.000	0.00
345 kV	54	290	0.5%	0.039	920.03
345 kV SSVT	6	290	0.5%	0.004	102.23
230 kV		189	0.5%	0.000	0.00
145 kV		90	0.5%	0.000	0.00
69 kV		75	0.5%	0.000	0.00
			Total	**0.04**	**1022.25**

SF6 GWP 23,500

Methodology
A worst-case leak rate of 0.5% per year was used from the U.S. EPA report, SF6 Leak Rates from High Voltage Circuit Breakers - EPA Investigates Potential Greenhouse Gas Emission Source, J. Blackman, Program Manager, EPA and M. Averyt, ICF Consulting, and Z. Taylor, ICF Consulting.
40 CFR 98 Subparts A 2025 GWP is used for this evaluation.
SF6 Emission Rate (tpy) = Breaker Count * Total SF6 per Component (lb) * SF_6 Leak Rate (%/yr) * 1ton/2000lb
CO_2e = SF6 Emission Rate (tpy) * Global Warming Potential for SF_6 (23,500)

Appendix A: Emission Calculations
Natural Gas Piping Systems - CCCT Turbines

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Proposed operation: *Natural Gas Piping Components*

Component Type	Component Count	Emission Factor[1] (scf/hr/component)	Natural Gas (Methane) (tons/yr)	CO2e Emissions (ton/yr)	VOC Emissions (ton/yr)
Connectors	2800	0.017	8.67	242.90	0.18
Flanges	2800	0.003	1.53	42.86	0.03
Valves	1200	0.123	26.90	753.18	0.56
Open Ended Pipes	240	0.123	5.38	150.64	0.11
Pump/Compressor Seals	12	13.3	29.09	814.41	0.61
Relief Valves	20	0.193	0.70	19.70	0.01
		Total	**72**	**2024**	**1.52**

CO2e GWP[3]	28
Specific Volume[2]	24
VOC content of NG	2.1%

Methodology

1. The emission factors are default whole gas emission factors from 40 CFR Part 98, Table W-1A for onshore natural gas production, Western U.S. In accordance with Table W-1A Footnote 1, for multi-phase flow that includes gas, use the gas service emissions factors.
2. The specific volume of methane at 68 oF is based on a specific volume of 385.5 standard cubic feet per lb-mole of gas, and a methane molecular weight of 16.0 lb/lb-mole.
3. Methane emissions are based on the worst-case assumption that natural gas is 100% methane by volume. 40 CFR 98 Subparts A 2025 GWP is used.
4. VOC emissions are based on the typical VOC content of the NG as 2.1% VOCs on a mass basis.

Appendix A: Emission Calculations
Diesel Storage Tank

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Proposed operation: *Diesel Storage Tank*

Emission Unit ID	Storage Capacity (gallons)	Annual Throughput (gal/year)	Shell length (ft)	Shell diameter (ft)	Max liquid height (ft)	Min liquid height (ft)	Vapor space pressure (psig)	Insulated/ underground	Shell Characterstics	Control
TKCC1	5,000	130,000	13.5	8	7	3	0	No	Aluminum/ Good	None

EPA's Tanks 5.1 web software used to estimate routine losses from the proposd tanks
https://www.epa.gov/air-emissions-factors-and-quantification/tanks-emissions-estimation-software-version-5

Emission Unit ID	Standing losses (lb/year)	Working losses (lb/year)	VOC Emissions (TPY)
TKCC1	0.74	2.03	1.38E-03

Appendix A: Emissions Calculations
2025 CCCT Project Unit's Specifications

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Table 2-1: General Specifications for the CCGTs

Parameter		Value
	Manufacturer	General Electric
	Model	7HA.02
	Type	Advanced Class CT
	Number of Units	4
Simple Cycle	ISO Base Output Power, MW net (each CT)	384
	ISO Heat Rate, Full Load, Net (based on LHV), Btu/kWh	8009
	Full Load Heat Input for site, MMBtu/hr (based on HHV at 4.1 °F)	3204
	Maximum capacity factor for each CT*	40%
Combined Cycle	ISO Base Output Power, MW net (Block -2 CTs and 1 ST)	1148
	ISO Heat Rate, Full Load, Net (based on LHV), Btu/kWh	5365
	Maximum CT Heat Input, MMBtu/hr (each CT, HHV at 4.1 °F)	3400
	Maximum DB Heat Input, MMBtu/hr(each unit, HHV at 4.1 °F)	987
	Maximum capacity factor for each CT including SU/SD	100%

* NSPS TTTTa criteria for simple cycle units

Table 3-1. Design Parameters for the Proposed GE 7HA.02 CTs (Unit 21A, Unit 21B, Unit 22A, and Unit 22B)

Parameter	Simple Cycle Mode	Combined Cycle Mode	Units
CT heat input (100% load, 4.1 °F)	3204	3400	MMBtu/hr (HHV)
Duct Burner heat input	N/A	987	MMBtu/hr (HHV)
Startup/shutdown per CT	365	365	Events/year
Startup duration*	30	30	Minutes
Shutdown duration	15	15	Minutes
Annual capacity factor*	40%	100% (includes SU/SD)	
Duct burner operation	N/A	2000	Hours/year

* Emissions are based on 'hot' startups for the CTs.
** NSPS TTTTa criteria for simple cycle units

Table 3-2. CTs Startup and Shutdown Emissions as (per the Manufacturer)

Event	Duration (minutes)	Emissions (lb)			
		CO	NOx	PM10/PM2.5	VOC
Cold Startup	70	310	420	19.0	100
Warm Startup	60	230	260	16.3	85
Hot Startup*	30 (combined cycle) 21 (simple cycle)	200	135	14.0	80
Shutdown	12	175	40	3.1	60

* Even though hot startup duration for simple cycle mode for the CT is shorter, NIPSCO conservatively assumed emissions to be same as for combined cycle hot startup for the CT.

Table 3-3. Emission Rates for GE 7HA.02 CT for Normal operation in Simple Cycle and Combined Cycle Modes

Pollutant	CT Simple Cycle Mode	CT Combined Cycle Mode		Unit
		Without Duct Burner	With Duct Burner	
PM*	8.05	6.55	12.25	lb/hr
PM10	16.1	13.10	24.50	lb/hr
PM2.5	16.1	13.10	24.50	lb/hr
SO2	5.1	5.40	6.90	lb/hr
NOx	195.4	144.83	34.76	lb/hr
VOC**	9.1	9.60	15.40	lb/hr
CO**	15.9	16.80	21.50	lb/hr
SAM	7.6	2.70	4.50	lb/hr
CO2e	116.98	116.98	116.98	lb/MMBtu
CH4	0.06	0.06	0.06	lb/MMBtu
N2O	0.07	0.07	0.07	lb/MMBtu

Emission rates for all pollutants are provided by the source based on the information provided by the equipment supplier/vendor
* PM filterable is assumed as 50% of the PM10 (filterable + condensable) rate provided by the vendor
** VOC and CO emission rates are based on the use of CO oxidation catalyst controls for both simple cycle and combined cycle modes for the proposed CTs.

Appendix A: Emission Calculations
PSD Significance Determination

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Projected commence construction date first CT			Jan-2025	
Projected start of operation date first CT			Dec-2027	
Contemporaneous period		Jan-2020	to	Dec-2027
Contemporaneous changes				
Unit 14 shutdown	Jul-2020			
Unit 15 shutdown	Sep-2021			
Temporary NG Boiler Start	Nov-2020			

Contemporaneous Decreases (tons/year)

Process/Emission Unit	PM	PM10	PM2.5	SO2	NOx	VOC	CO	H2SO4	CO2e
Unit 14 Shutdown (Baseline period 2018-2019)									
Projected Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Baseline Actual Emissions	79.53	141.27	115.86	139.19	718.30	46.10	212.64	33.84	1741238
BAE (Unit 14)	-79.53	-141.27	-115.86	-139.19	-718.30	-46.10	-212.64	-33.84	-1741238.20
Unit 15 Shutdown (Baseline period 2018-2019)									
Projected Actual Emissions	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Baseline Actual Emissions	68.26	259.64	246.04	171.54	1448.14	36.21	4622.34	4.63	4121693
BAE (Unit 15)	-68.26	-259.64	-246.04	-171.54	-1448.14	-36.21	-4622.34	-4.63	-4121692.67
BAE	***-147.79***	***-400.91***	***-361.89***	***-310.73***	***-2166.44***	***-82.31***	***-4834.98***	***-38.46***	***-5862931***

Contemporaneous Emissions Increases

Contemporaneous Increases (tons/year)

Process/Emission Unit	PM	PM10	PM2.5	SO2	NOx	VOC	CO	H2SO4	CO2e
Temporary Boiler Installed in 2020									
Actual Emissions (period 2023)	0.11	0.44	0.44	0.03	2.13	0.32	2.17	0.00	6863
Emissions Increase	***0.11***	***0.44***	***0.44***	***0.03***	***2.13***	***0.32***	***2.17***	***0.00***	***6863***

2024 Peaker Project Emissions (ton/yr)

	PM	PM10	PM2.5	SO2	NOx	VOC	CO	H2SO4	CO2e
2024 Peaker Project Emission Increase	38.90	68.45	68.45	14.83	539.77	73.35	411.95	24.98	1233629

Net Emissions Increase (ton/yr)

	PM	PM10	PM2.5	SO2	NOx	VOC	CO	H2SO4	CO2e
2024 Peaker Project Units	38.90	68.45	68.45	14.83	539.77	73.35	411.95	24.98	1233629
Contemporaneous Increase	0.11	0.44	0.44	0.03	2.13	0.32	2.17	0.00	6863
Contemporaneous Decrease	-147.79	-400.91	-361.89	-310.73	-2166.44	-82.31	-4834.98	-38.46	-5862931
Net Emissions Increase	**-108.78**	**-332.01**	**-293.01**	**-295.86**	**-1624.53**	**-8.65**	**-4420.86**	**-13.49**	**-4622440**
Significance Threshold (tpy)	25	15	10	40	40	40	100	7.00	75,000

Appendix A: Emission Calculations
Unit 14 & Unit 15 Actual Emissions

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Baseline Actual Emissions for Contemporaneous Changes

	2018 Emissions (ton/yr)		2019 Emissions (ton/yr)		BAE* (ton/yr)		Total
Pollutant	Unit 14	Unit 15	Unit 14	Unit 15	Unit 14	Unit 15	
PM	64.61	84.45	94.45	52.07	79.53	68.26	**147.79**
PM10	139.89	301.05	142.65	218.22	141.27	259.64	**400.91**
PM2.5	119.26	284.22	112.45	207.85	115.86	246.04	**361.89**
SO2	163.42	211.41	114.96	131.67	139.19	171.54	**310.73**
NOx	760.15	1,668.56	676.45	1,227.71	718.30	1,448.14	**2,166.44**
VOC	50.38	41.46	41.82	30.96	46.10	36.21	**82.31**
CO	232.83	5,262.40	192.44	3,982.28	212.64	4,622.34	**4,834.98**
H2SO4 mist	28.40	5.36	39.27	3.90	33.84	4.63	**38.46**
CO2e	1,889,267.06	2,711,875.42	1,593,209.33	2,049,033.53	1,741,238.20	2,380,454.48	**4,121,692.67**

* BAE: Baseline Actual Emissions

Emissions reported in the site emissions inventories
PM data has been updated to reflect PMf CEMS reported emissions

	2018	2019		
Unit 15 coal heat input	25,545,640	19,331,471	MMBtu	
CO factor for Unit 15	0.41	lb/MMBtu		
CO stack test for Unit 15 - December 3, 2019				

	2018	2019	BAE	
Unit 15 CO emissions	5,262.4	3,982.3	4,622.3	TPY

Notes
PM, PM10, PM2.5 NOx, and VOC emissions from Unit 14 and Unit 15 and CO emissions from Unit 14, as reported to IDEM in the emissions inventories, during the 2018-19 period are selected as Baseline Actual Emissions (BAE).

A December 2019 CO stack test for Unit 15 demonstrates a CO emission rate of 0.41 lb/MMBtu of heat input to the unit. NIPSCO used the coal combustion heat input for 2018 and 2019 for Unit 15 and the CO emission factor from the stack test to estimate actual CO emissions as BAE for this unit.

Appendix A: Emission Calculations
PSD Significance Determination

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

2024 Peaker Project Emissons

Unlimited PTE of New Emission Units (ton/yr)									
Emission Units	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**H2SO4**	**CO2e**
Units 19A, 19B, and 19C	42.45	78.54	78.54	13.24	595.38	52.85	212.24	21.13	1,042,294
Unit 20	36.43	69.93	69.93	20.52	602.99	63.91	312.45	14.22	1,500,366
Emergency Generator EDG1	0.24	0.29	0.28	0.01	7.69	0.47	4.20	0.00	850
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	0.01	94
Peaker - Circuit Breakers	--	--	--	--	--	--	--	--	85
Peaker - N.G Piping Systems	--	--	--	--	--	0.43	--	--	570
Total	***79.15***	***148.94***	***148.94***	***33.94***	***1206.60***	***117.77***	***529.36***	***35.35***	***2544261***

Limited PTE of New Emission Units (ton/yr)									
Emission Units	**PM**	**PM10**	**PM2.5**	**SO2**	**NOx**	**VOC**	**CO**	**H2SO4**	**CO2e**
Units 19A, 19B, and 19C	21.59	36.84	36.84	5.78	265.34	24.09	135.30	10.75	530,244
Unit 20	17.04	31.15	31.15	8.88	266.21	48.25	271.98	14.22	701,784
Emergency Generator EDG1	0.24	0.29	0.28	0.01	7.69	0.47	4.20	0.00	850
Fire Pump FP1	0.03	0.18	0.18	0.17	0.54	0.11	0.47	0.01	94
Peaker - Circuit Breakers	--	--	--	--	--	--	--	--	85
Peaker - N.G Piping Systems	--	--	--	--	--	0.43	--	--	570
Total	***38.90***	***68.45***	***68.45***	***14.83***	***539.77***	***73.35***	***411.95***	***24.98***	***1233629***

Appendix A: Emissions Calculations
Turbines 19A, 19B, and 19C

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Projected Operation			HHV mmBtu / mmscf	Potential Throughput MMCF/yr
Maximum Heat input per Turbine	519	MMBtu/hr	1020	4457.29
Output (gross)	55	MW		
Number of Turbines:	3			
Annual capacity factor	40.0%	NSPS TTTTa criteria for simple cycle units capacity factor restriction applicable to the turbines (40 CFR 60.5580a)		
Number of SU/SD	4	events per day		
CT operation	1,460	events/year		
Startup duration for CT*	0.17	hour		
Shutdown duration for CT**	0.15	hour		
Heat input during events***	73.60	MMBtu/event		
Worst case sulfur in NG	0.50	gr/100 cf		
SO2 emission factor	0.002	lb/MMBtu		
Oxidation Catalyst Control	50%	for VOC		
Oxidation Catalyst Control	90%	for CO		
SO2 to SAM conversion (fuel)	8%	Per S&L conservative estimate		
SO2 to SAM conversion (Ox Cat)	90%	Per S&L based on catalyst curve		

Unlimited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation (3 Turbines)	Startup/Shutdown (3 Turbines)	Total Combined (3 turbines)
PM	2.90 lb/hr	2.90 lb/event	36.09 tons/yr	6.35 tons/yr	42.45 tons/yr
PM10	5.80 lb/hr	2.90 lb/event	72.19 tons/yr	6.35 tons/yr	78.54 tons/yr
PM2.5	5.80 lb/hr	2.90 lb/event	72.19 tons/yr	6.35 tons/yr	78.54 tons/yr
SO2	1.04 lb/hr	0.15 lb/event	12.92 tons/yr	0.32 tons/yr	13.24 tons/yr
NOx	45.90 lb/hr	11.00 lb/event	571.29 tons/yr	24.09 tons/yr	595.38 tons/yr
VOC	4.00 lb/hr	1.40 lb/event	49.79 tons/yr	3.07 tons/yr	52.85 tons/yr
CO	10.70 lb/hr	36.10 lb/event	133.18 tons/yr	79.06 tons/yr	212.24 tons/yr
SAM	1.44 lb/hr	1.44 lb/event	17.96 tons/yr	3.16 tons/yr	21.13 tons/yr
CO2e	71212 lb/hr	71212 lb/event	886340 tons/yr	155954 tons/yr	1042294 tons/yr

Limited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation (3 Turbines)	Startup/Shutdown (3 Turbines)	Total Combined (3 Turbines)
PM	2.90 lb/hr	2.90 lb/event	15.24 tons/yr	6.35 tons/yr	21.59 tons/yr
PM10	5.80 lb/hr	2.90 lb/event	30.48 tons/yr	6.35 tons/yr	36.84 tons/yr
PM2.5	5.80 lb/hr	2.90 lb/event	30.48 tons/yr	6.35 tons/yr	36.84 tons/yr
SO2	1.04 lb/hr	0.15 lb/event	5.46 tons/yr	0.32 tons/yr	5.78 tons/yr
NOx	45.90 lb/hr	11.00 lb/event	241.25 tons/yr	24.09 tons/yr	265.34 tons/yr
VOC	4.00 lb/hr	1.40 lb/event	21.02 tons/yr	3.07 tons/yr	24.09 tons/yr
CO	10.70 lb/hr	36.10 lb/event	56.24 tons/yr	79.06 tons/yr	135.30 tons/yr
SAM	1.44 lb/hr	1.44 lb/event	7.59 tons/yr	3.16 tons/yr	10.75 tons/yr
CO2e	71212 lb/hr	71212 lb/event	374290 tons/yr	155954 tons/yr	530244 tons/yr

Controlled Emissions

Pollutant	Normal Operation (1 Turbines)	Startup/Shutdown (1 Turbines)	Total Combined (1 turbines)	Total Combined (3 Turbines)
PM	12.03 tons/yr	2.12 tons/yr	14.15 tons/yr	42.45 tons/yr
PM10	24.06 tons/yr	2.12 tons/yr	26.18 tons/yr	78.54 tons/yr
PM2.5	24.06 tons/yr	2.12 tons/yr	26.18 tons/yr	78.54 tons/yr
SO2	4.31 tons/yr	0.11 tons/yr	4.41 tons/yr	13.24 tons/yr
NOx	190.43 tons/yr	8.03 tons/yr	198.46 tons/yr	595.38 tons/yr
VOC	8.30 tons/yr	0.51 tons/yr	8.81 tons/yr	26.43 tons/yr
CO	4.44 tons/yr	2.64 tons/yr	7.07 tons/yr	21.22 tons/yr
SAM	5.99 tons/yr	1.05 tons/yr	7.04 tons/yr	21.13 tons/yr
CO2e	295446.68 tons/yr	51984.75 tons/yr	347431.43 tons/yr	1042294.29 tons/yr

Methodology:
* Startup duration for each turbine is 10 minutes = 0.17 hour (10 min / 60 minu = 0.17 hour)
** Shutdown duration for each turbine is 9 minutes = 0.15 hour (9 min / 60 min = 0.15 jour)
*** Heat input during starup/shutdown events for the turbines was provided by the source based on vendor data.

Emission rates for PM, NOx, VOC, and CO are provided by the source based on the information provided by the equipment supplier/vendor (emissions vary by ambient temperature and turbine load using the worst case for PTE estimate)
Emission Factor for SO2 is calculated based on the maximum sulfur contentspecified for natural gas in 40 CFR § 72.2.
Unlimited PTE (tons/yr) = Worst Case Emission Factor (lb/hr) * 8760 (hrs/yr) * 1 ton/ 2000 lbs
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.0%)
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
PTE CO2e (lb/hr) = [CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (28) + N2O Potential Emission ton/yr x N2O GWP (265)] x Heat Input Capacity of the turbine.(MMbtu/hr)

Pollutants	Emission Factors		***Unlimited HAP Emissions***		***Limited HAP Emissions***	
Hexane	2.54E-04	lb/MMBtu	1.73	tons/yr	0.87	tons/yr
1,3-Butadiene	4.3E-07	lb/MMBtu	0.00	tons/yr	0.00	tons/yr
Acetaldehyde	4.00E-05	lb/MMBtu	0.27	tons/yr	0.14	tons/yr
Acrolein	6.40E-06	lb/MMBtu	0.04	tons/yr	0.02	tons/yr
Benzene	1.20E-05	lb/MMBtu	0.08	tons/yr	0.04	tons/yr
Ethylbenzene	3.20E-05	lb/MMBtu	0.22	tons/yr	0.11	tons/yr
Formaledyhyde	0.920	lb/hr	12.09	tons/yr	6.04	tons/yr
Napathalene	1.30E-06	lb/MMBtu	0.01	tons/yr	0.00	tons/yr
PAH	2.20E-06	lb/MMBtu	0.02	tons/yr	0.01	tons/yr
Proplene Oxide	2.90E-05	lb/MMBtu	0.20	tons/yr	0.10	tons/yr
Toluene	1.30E-04	lb/MMBtu	0.89	tons/yr	0.44	tons/yr
Xylene	6.40E-05	lb/MMBtu	0.44	tons/yr	0.22	tons/yr
	Total HAP Emissions		**15.99**	**tons/yr**	**7.99**	**tons/yr**
	Single Worst HAP Emission		**12.09**	**tons/yr**	**6.04**	**tons/yr**

Methodology
Emission Factors from AP-42, Chapter 3.1 (Stationary Gas Turbines) - Table 3.1-3
Hexane EF from BAAQMD TAC Emission Factor Guidelines, 8/2020
Emission rates for Formaldhyde is provided by the source based on the information provided by the equipment supplier/vendor (greater than emission listed under AP-42 - Chapter 3.1 - Table 3.1-3)
For combined total HAPs compliance determination calculations, formaldehyde emission factor can be converted from lb/hr into lb/MMBtu as follows: 0.920 (lb/hr) / 519 (MMBtu/h 0.00177
Unlimited PTE (tons/yr) = Maximum Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 8760 (hr/yr) * (1 ton / 2000 lbs)
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.0%)

Appendix A: Emissions Calculations
Turbine 20

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Projected Operation			HHV mmBtu / mmscf	Potential Throughput MMCF/yr
Maximum Heat input per Turbine	2416	MMBtu/hr	1020	20749.18
Output (gross)	247	MW		
Number of Turbines:	1			
Annual capacity factor	40.0%	NSPS TTTTa criteria for simple cycle units capacity factor restriction applicable to the turbines (40 CFR 60.5580a)		
Number of SU/SD	2	events per day		
CT operation	730	events/year		
Startup duration for CT	0.35	hour		
Shutdown duration for CT	0.25	hour		
Heat input during events	564	MMBtu/event		
Worst case sulfur in NG	0.50	gr/100 cf		
SO2 emission factor	0.002	lb/MMBtu		
Oxidation Catalyst Control	50%	for VOC		
Oxidation Catalyst Control	90%	for CO		
SO2 to SAM conversion (fuel)	8%	Per S&L conservative estimate		
SO2 to SAM conversion (Ox Cat)	90%	Per S&L based on catalyst curve		

Unlimited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation	Startup/Shutdown	Total Combined
PM	8.05 lb/hr	8.05 lb/event	33.50 tons/yr	2.94 tons/yr	36.43 tons/yr
PM10	16.10 lb/hr	8.05 lb/event	66.99 tons/yr	2.94 tons/yr	69.93 tons/yr
PM2.5	16.10 lb/hr	8.05 lb/event	66.99 tons/yr	2.94 tons/yr	69.93 tons/yr
SO2	4.83 lb/hr	1.13 lb/event	20.11 tons/yr	0.41 tons/yr	20.52 tons/yr
NOx	139.80 lb/hr	58.30 lb/event	581.71 tons/yr	21.28 tons/yr	602.99 tons/yr
VOC	6.50 lb/hr	101.00 lb/event	27.05 tons/yr	36.87 tons/yr	63.91 tons/yr
CO	16.80 lb/hr	664.50 lb/event	69.90 tons/yr	242.54 tons/yr	312.45 tons/yr
SAM	6.72 lb/hr	6.72 lb/event	27.96 tons/yr	2.45 tons/yr	30.41 tons/yr
CO2e	331499.36 lb/hr	331499.36 lb/event	1379368.84 tons/yr	120997.27 tons/yr	1500366 tons/yr

Limited Emissions

Pollutant	Emission Rate in Normal Operation Conditions	Emission Rate in Startup/Shutdown Conditions	Normal Operation	Startup/Shutdown	Total Combined
PM	8.05 lb/hr	8.05 lb/event	14.10 tons/yr	2.94 tons/yr	17.04 tons/yr
PM10	16.10 lb/hr	8.05 lb/event	28.21 tons/yr	2.94 tons/yr	31.15 tons/yr
PM2.5	16.10 lb/hr	8.05 lb/event	28.21 tons/yr	2.94 tons/yr	31.15 tons/yr
SO2	4.83 lb/hr	1.13 lb/event	8.47 tons/yr	0.41 tons/yr	8.88 tons/yr
NOx	139.80 lb/hr	58.30 lb/event	244.93 tons/yr	21.28 tons/yr	266.21 tons/yr
VOC	6.50 lb/hr	101.00 lb/event	11.39 tons/yr	36.87 tons/yr	48.25 tons/yr
CO	16.80 lb/hr	664.50 lb/event	29.43 tons/yr	242.54 tons/yr	271.98 tons/yr
SAM	6.72 lb/hr	6.72 lb/event	11.77 tons/yr	2.45 tons/yr	14.22 tons/yr
CO2e	331499 lb/hr	331499 lb/event	580787 tons/yr	120997 tons/yr	701784 tons/yr

Controlled Emissions

Pollutant	Normal Operation	Startup/Shutdown	Total Combined
PM	33.50 tons/yr	2.94 tons/yr	36.43 tons/yr
PM10	66.99 tons/yr	2.94 tons/yr	69.93 tons/yr
PM2.5	66.99 tons/yr	2.94 tons/yr	69.93 tons/yr
SO2	20.11 tons/yr	0.41 tons/yr	20.52 tons/yr
NOx	581.71 tons/yr	21.28 tons/yr	602.99 tons/yr
VOC	13.52 tons/yr	18.43 tons/yr	31.96 tons/yr
CO	6.99 tons/yr	24.25 tons/yr	31.24 tons/yr
SAM	27.96 tons/yr	2.45 tons/yr	30.41 tons/yr
CO2e	1379368.84 tons/yr	120997.27 tons/yr	1500366.10 tons/yr

Methodology:
* Startup duration for each turbine is 10 minutes = 0.17 hour (10 min / 60 minu = 0.17 hour)
** Shutdown duration for each turbine is 9 minutes = 0.15 hour (9 min / 60 min = 0.15 jour)
*** Heat input during starup/shutdown events for the turbines was provided by the source based on vendor data.

Emission rates for PM, NOx, VOC, and CO are provided by the source based on the information provided by the equipment supplier/vendor (emissions vary by ambient temperature and turbine load using the worst case for PTE estimate)
Emission Factor for SO2 is calculated based on the maximum sulfur contentspecified for natural gas in 40 CFR § 72.2.
Unlimited PTE (tons/yr) = Worst Case Emission Factor (lb/hr) * 8760 (hrs/yr) * 1 ton/ 2000 lbs
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.0%)
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
PTE CO2e (lb/hr) = [CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (28) + N2O Potential Emission ton/yr x N2O GWP (265)] x Heat Input Capacity of the turbine.(MMbtu/hr)

Pollutants	Emission Factors	***Unlimited HAP Emissions***	***Limited HAP Emissions***
Hexane	2.50E-04 lb/MMBtu	2.65 tons/yr	1.32 tons/yr
1,3-Butadiene	4.3E-07 lb/MMBtu	0.00 tons/yr	0.00 tons/yr
Acetaldehyde	4.00E-05 lb/MMBtu	0.42 tons/yr	0.21 tons/yr
Acrolein	6.40E-06 lb/MMBtu	0.07 tons/yr	0.03 tons/yr
Benzene	1.20E-05 lb/MMBtu	0.13 tons/yr	0.06 tons/yr
Ethylbenzene	3.20E-05 lb/MMBtu	0.34 tons/yr	0.17 tons/yr
Formaledyhyde	1.10 lb/hr	4.82 tons/yr	2.41 tons/yr
Napathalene	1.30E-06 lb/MMBtu	0.01 tons/yr	0.01 tons/yr
PAH	2.20E-06 lb/MMBtu	0.02 tons/yr	0.01 tons/yr
Proplene Oxide	2.90E-05 lb/MMBtu	0.31 tons/yr	0.15 tons/yr
Toluene	1.30E-04 lb/MMBtu	1.38 tons/yr	0.69 tons/yr
Xylene	6.40E-05 lb/MMBtu	0.68 tons/yr	0.34 tons/yr
	Total HAP Emissions	**10.82 tons/yr**	**5.41 tons/yr**
	Single Worst HAP Emission	**4.82 tons/yr**	**2.41 tons/yr**

Methodology
Emission Factors from AP-42, Chapter 3.1 (Stationary Gas Turbines) - Table 3.1-3
Hexane EF from BAAQMD TAC Emission Factor Guidelines, 8/2020
Emission rates for Formaldhyde is provided by the source based on the information provided by the equipment supplier/vendor (greater than emission listed under AP-42 - Chapter 3.1 - Table 3.1-3)
For combined total HAPs compliance determination calculations, formaldehyde emission factor can be converted from lb/hr into lb/MMBtu as follows: 0.920 (lb/hr) / 519 (MMBtu/hr) = 4.55E-04
Unlimited PTE (tons/yr) = Maximum Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 8760 (hr/yr) * (1 ton / 2000 lbs)
Limited PTE (tons/yr) = Unlimited PTE (tons/yr) * Design Efficiency Based Limit (40.0%)

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (>600 HP)
Maximum Input Rate (>4.2 MMBtu/hr)
Emergency Engine EDG1

Company Name: **NIPSCO LLC- R.M. Schahfer Generating Station**
Source Address: **2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.: **073-49556-00008**
Significant Permit Modification No: **073-49651-00008**
Reviewer: **Hachem Ismaili Alaoui**

The engine has been certified to comply with the emission standards in 40 CFR 60, Subpart IIII, New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines. Therefore, the NSPS Subpart IIII emission standards for PM, NOx, VOC, and CO are used as the emission factors to determine the potential to emit (PTE).

Emissions calculated based on output rating (hp)

NSPS Subpart IIII Emission Standards based on a: 2007 model year emergency engine

Output Horsepower Rating (hp)	2922.0	
Output Horsepower Rating (kw)	2178.9	
Maximum Hours Operated per Year	500	(emergency generator or fire pump)
Potential Throughput (hp-hr/yr)	1,461,000	
Potential Throughput (kw-hr/yr)	1,089,468	
Sulfur Content (S) of Fuel (% by weight)	0.0015	(ultra low sulfur diesel with sulfur content of 15 ppm pursuant to 40 CFR 60.4207(b))

	Pollutant							
	PM	PM10*	direct PM2.5*	SO2 *(.00809S)*	NOx[1]	VOC[1]	CO	H2SO4
AP-42 Emission Factor in lb/hp-hr		4.01E-04	3.89E-04	1.21E-05		0.0006		3%
40 CFR 60 (NSPS), Subpart IIII, Emission Standard (g/kw-hr)	0.20				6.40		3.5	
Potential Emissions ton/year								
Based on AP-42 lb/hr Emission Factor		0.29	0.28	0.01				
Based on g/kw-hr Emission Factor	0.24				7.69	0.47	4.20	
Potential Emission in tons/yr	**0.24**	**0.29**	**0.28**	**0.01**	**7.69**	**0.47**	**4.20**	**2.66E-04**

*The PM10 and PM2.5 emission factors for are from AP-42 Table 3.4-2. The PM10 emission factor is the sum of filterable PM10 and condensable particulate. The PM2.5 emission factor is the sum of filterable particulate less than 3 um and condensable particulate. Emission factors in lb/hp-hr were calculated using the emission factor in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Tables 3.3-1 and 3.4-1).

Note 1: For engines that have a combined NOx + NMHC emission standard under NSPS Subpart IIII, the individual NOx emission standards were estimated from the combined NOx + NMHC emission standard assuming 80% NOx based on the equation provided in 40 CFR 1039.740(c).

SAM emission factor is based on engineering estimate

Hazardous Air Pollutants (HAPs)

	Pollutant						
	Benzene	Toluene	Xylene	Formaldehyde	Acetaldehyde	Acrolein	Total PAH HAPs**
Emission Factor in lb/hp-hr***	5.43E-06	1.97E-06	1.35E-06	5.52E-07	1.76E-07	5.52E-08	1.48E-06
Potential Emission in tons/yr	3.97E-03	1.44E-03	9.87E-04	4.03E-04	1.29E-04	4.03E-05	1.08E-03

**PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
***Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Tables 3.3-1 and 3.4-1).

Potential Emission of Total HAPs (tons/yr)	**8.05E-03**	
Worste Single HAP	**3.97E-03**	Benzene

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Greenhouse Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.16E+00	6.35E-05	9.30E-06
Potential Emission in tons/yr	8.47E+02	4.64E-02	6.79E-03

Summed Potential Emissions in tons/yr	**8.47E+02**
CO2e Total in tons/yr	**8.50E+02**

Methodology
CO2 Emission Factor is from AP 42 (Supplement B 10/96) Table 3.4-1.
CH4 and N2O Emission Factors are from 40 CFR 98 Subpart C Table C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Potential Emission (tons/yr) = [Potential Throughput (MMBtu/yr)] * [Emission Factor (lb/MMBtu)] / [2,000 lb/ton]
CO2e (tons/yr) based on 11/29/2013 federal GWPs= CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (<=600 HP)
Fire Pump FP1

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

The engine has been certified to comply with the emission standards in 40 CFR 60, Subpart IIII, New Source Performance Standards (NSPS) for Stationary Compression Ignition Internal Combustion Engines. Therefore, the NSPS Subpart IIII emission standards for PM, NOx, VOC, and CO are used as the emission factors to determine the potential to emit (PTE).

Emissions calculated based on output rating (hp)

NSPS Subpart IIII Emission Standards based on a: 2009 model year emergency engine

Output Horsepower Rating (hp)	327.0	
Output Horsepower Rating (kw)	243.8	
Maximum Hours Operated per Year	500	(emergency generator or fire pump)
Potential Throughput (hp-hr/yr)	163,500	
Potential Throughput (kw-hr/yr)	121,922	
Sulfur Content (S) of Fuel (% by weight)	0.0015	(ultra low sulfur diesel with sulfur content of 15 ppm pursuant to 40 CFR 60.4207(b))

	Pollutant							
	PM	PM10*	direct PM2.5*	SO2	NOx[1]	VOC[1]	CO	H2SO4
AP-42 Emission Factor in lb/hp-hr		0.0022	0.0022	0.00205				3%
40 CFR 60 (NSPS), Subpart IIII, Emission Standard (g/kw-hr)	0.20				4.00	0.80	3.5	
Potential Emissions ton/year								
Based on AP-42 lb/hr Emission Factor		0.18	0.18	0.17				
Based on g/kw-hr Emission Factor	0.03				0.54	0.11	0.47	
Potential Emission in tons/yr	**0.03**	**0.18**	**0.18**	**0.17**	**0.54**	**0.11**	**0.47**	**0.005**

*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.
Note 1: For engines that have a combined NOx + NMHC emission standard under NSPS Subpart IIII, the individual NOx and VOC emission standards were estimated from the combined NOx + NMHC emission standard assuming 80% NOx and 20% VOC (NMHC) based on the equation provided in 40 CFR 1039.740(c).
SAM emission factor is based on engineering estimate

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
Potential Emission in tons/yr	5.34E-04	2.34E-04	1.63E-04	2.24E-05	6.75E-04	4.39E-04	5.29E-05	9.61E-05

**PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
***Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu / hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**2.22E-03**	
Worste Single HAP	**6.75E-04**	Benzene

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.3-1 and 3.3-2.
Output Horsepower Rating (kw) = Output Horsepower Rating (hp) * (0.7457 kw/hp)
Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Throughput (kw-hr/yr) = [Output Horsepower Rating (kw)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] * [ton/2,000 lbs]
Potential Emission (tons/yr) = [Potential Throughput (kw-hr/yr)] * [Emission Factor (g/kw-hr)] * [lb / 453.592 g] * [ton/2,000 lbs]

Greenhouse Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.15E+00	4.63E-05	9.26E-06
Potential Emission in tons/yr	9.40E+01	3.78E-03	7.57E-04

Summed Potential Emissions in tons/yr	**9.40E+01**
CO2e Total in tons/yr	**9.43E+01**

Methodology
CO2 Emission Factor is from AP42 (Supplement B 10/96), Tables 3.3-1.
CH4 and N2O Emission Factors are from 40 CFR 98 Subpart C Table C-2.

Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.

Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential

Appendix A: Emission Calculations
Fugitive Equipment Leaks-Circuit Breakers - Peaker Turbines

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Proposed operations: *Circuit breakers with SF6*

Breaker Type	Breaker Count	Total SF6 per Component (lbs)	Leak Rate (% per year)	SF6 emissions (ton/yr)	CO2e Emissions (ton/yr)
500 kV		1,437	0.5%	0.000	0.00
345 kV	5	290	0.5%	0.004	85.19
345 kV SSVT		290	0.5%	0.000	0.00
230 kV		189	0.5%	0.000	0.00
145 kV		90	0.5%	0.000	0.00
69 kV		75	0.5%	0.000	0.00
			Total	**0.00**	**85.19**

SF6 GWP 23,500

Methodology
A worst-case leak rate of 0.5% per year was used from the U.S. EPA report, SF6 Leak Rates from High Voltage Circuit Breakers - EPA Investigates Potential Greenhouse Gas Emission Source, J. Blackman, Program Manager, EPA and M. Averyt, ICF Consulting, and Z. Taylor, ICF Consulting.
CO2e based on 2025 GWP in 40 CFR 98 Subpart A Table A-1
SF6 Emission Rate (tpy) = Breaker Count * Total SF6 per Component (lb) * SF_6 Leak Rate (%/yr) * 1ton/2000lb
CO_2e = SF6 Emission Rate (tpy) * Global Warming Potential for SF_6 (23,500)

Appendix A: Emission Calculations
Natural Gas Piping Systems - Peaker Turbines

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Proposed operation: *Natural Gas Piping Components*

Component Type	Component Count	Emission Factor[1] (scf/hr/component)	Natural Gas (Methane) (tons/yr)	CO2e Emissions (ton/yr)	VOC Emissions (ton/yr)
Connectors	700	0.017	2.17	60.72	0.05
Flanges	400	0.003	0.22	6.12	0.00
Valves	300	0.123	6.72	188.29	0.14
Open Ended Pipes	60	0.123	1.34	37.66	0.03
Pump/Compressor Seals	4	13.3	9.70	271.47	0.20
Relief Valves	6	0.193	0.21	5.91	0.00
		Total	**20.36**	**570.18**	**0.43**

CO2e GWP[3]	28
Specific Volume[2]	24
VOC content of NG	2.1%

Methodology

1. The emission factors are default whole gas emission factors from 40 CFR Part 98, Table W-1A for onshore natural gas production, Western U.S. In accordance with Table W-1A Footnote 1, for multi-phase flow that includes gas, use the gas service emissions factors.
2. The specific volume of methane at 68 oF is based on a specific volume of 385.5 standard cubic feet per lb-mole of gas, and a methane molecular weight of 16.0 lb/lb-mole.
3. Methane emissions are based on the worst-case assumption that natural gas is 100% methane by volume. 40 CFR 98 Subparts A 2025 GWP is used.
4. VOC emissions are based on the typical VOC content of the NG as 2.1% VOCs on a mass basis.

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr
99.9	1020	858.0

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	37.1 **see below	5.5	37.7
Potential Emission in tons/yr	0.82	3.26	3.26	0.26	15.92	2.36	16.17

*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 at 30 ppm for unit with FGR and CO at 50 ppm from vendor information.

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics					
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene	**Total - Organics**
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.50E-02	1.8E+00	3.4E-03	
Potential Emission in tons/yr	9.0E-04	5.1E-04	3.2E-02	0.77	1.5E-03	**0.81**

	HAPs - Metals					
	Lead	Cadmium	Chromium	Manganese	Nickel	**Total - Metals**
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr	2.1E-04	4.7E-04	6.0E-04	1.6E-04	9.0E-04	**2.4E-03**
Methodology is the same as above.					**Total HAPs**	**0.81**
The five highest organic and metal HAPs emission factors are provided above.					**Worst HAP**	**0.77**
Additional HAPs emission factors are available in AP-42, Chapter 1.4.						

Greenhouse Gases (GHGs)

	Greenhouse Gas		
	CO2	CH4	N2O
Emission Factor in lb/MMcf	120,000	2.3	2.2
Potential Emission in tons/yr	51,478	0.99	0.94
Summed Potential Emissions in tons/yr	51,480		
CO2e Total in tons/yr	51,784		

Methodology
The N2O Emission Factor for uncontrolled is 2.2. The N2O Emission Factor for low Nox burner is 0.64.
Emission Factors are from AP 42, Table 1.4-2 SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

Appendix A: Emission Calculations
Coal Burning - Coal Boilers #17

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)
3967	11111	1.56E+06

	Weight %		Weight %
Sulfur =	3.2	Ash =	8.90

Uncontrolled PTE	Pollutant (tons per year)						
	PM	PM10	PM2.5	SO2	NOx	VOC	CO
Uncontrolled Emission Factor in lb/ton	89.0 *(10A)*	20.47 *(2.3A)*	20.47 *(2.3A)*	121.6 *(38S)*	12.0	0.06	0.50
Limited Emission Factor in lb/MMBtu	0.03				0.60		
Uncontrolled Potential Emission in tons/yr	69,589	16,006	16,006	95,079	9,383	47	391
Limited Potential Emission in tons/yr	*521*				*10,425*		

Note:
Limited NOx will be assumed to equal the Uncontrolled Potential emission, since using the limits set in the permit of 0.6 lb/MMBtu will give a higher number than the uncontrolled PTE for boiler 17.

Methodology
The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
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; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
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)
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Limited Emission Factor in lb/MMBtu * 8760hours/1yr * 1ton/2000lbs

Uncontrolled HAP's	Pollutant					
	HCl	HF	Benzene	Benzyl Chloride	Cyanide	Isophorone
Emission Factor in lb/ton	1.2E+00	1.5E-01	1.3E-03	7.0E-04	2.5E-03	5.8E-04
Potential Emission in tons/yr	938.3	117.3	1.0	0.5	2.0	0.5

Emission Factors from AP-42, Chapter 1.1 (Controlled Coal Combustion): Table 15, Hydrogen Chloride and Hydrogen Fluoride; Table 14, Var. Org. Comp.
Methodology:
Potential Emission in tons/yr = Emission Factor in lb/ton * Potential Througput (ton/yr) * 1ton/2000lbs

Uncontrolled HAP's	Pollutant					
	As	Be	Cr	Pb	Mn	Ni
Emission Factor in lb/MMBtu	6.84E-04	8.10E-05	1.57E-03	5.07E-04	2.98E-03	1.29E-03
Potential Emission in lb/hour	2.71	0.32	6.23	2.01	11.82	5.12
Potential Emission in tons/yr	11.88	1.41	27.28	8.81	51.78	22.41

Emission Factors from AP-42, Chapter 1.1, Table 17: Trace Elements, Uncontrolled Bituminous Coal Combustion. (SCC 1-01-002-02/

Total HAPs	1211.34
Worst Single	938.3

Methodology:
Emission Factor in lb/MMBtu = Emission Factor lb/10^12Btu * 1TrillionBtu/1000000 MMBtu
Potential Emission in lb/hour = Emission Factor in lb/MMBtu * Heat Input Capacity (MMBtu/hour)
Potential Emission in tons/yr = Potential Emission in lb/hour * 8760hour/1year * 1ton/2000lbs

	Greenhouse Gases		
	CO_2	CH_4	N_2O
Emission Factor, lb/ton	4810	0.04	0.03
Potential Emission, ton/yr	3,760,956	31	23
Summed Potential Emissions, tons/yr	3,761,011		
Global Warming Potential (100 Year)	1	25	298
CO2e Total in tons/yr	3,768,728		

Methodology
Emission Factor (lb/ton) from AP 42 Tables 1.1-19 (PC-fired, dry bottom, wall fired (SCC 1-001-002-02/22)) and 1.1-20 (Subbituminous)
Pursuant to Table C-1 of 40 CFR Part 98 Subpart C, Bituminous coal has a default high heat value of 24.93 MMBtu/ton
Greenhouse Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (tons/yr) x Emission Factor (lb/ton)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential

Appendix A: Emission Calculations
Coal Burning - Coal Boilers #18

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity (MMBut/hr)	Heat Content of Coal (Btu/lb)	Potential Throughput (ton/yr)	Potential Throughput (ton/hr)
3967	11111	1.56E+06	1.79E+02

Sulfur =	Weight % 3.2	Ash =	Weight % 8.90

Uncontrolled PTE

	Pollutant (tons per year)						
	PM	PM10	PM2.5	SO2	NOx	VOC	CO
Uncontrolled Emission Factor in lb/ton	89.0 *(10A)*	20.47 *(2.3A)*	20.47 *(2.3A)*	121.6 *(38S)*	12.0	0.06	0.50
Limited Emission Factor in lb/MMBtu	0.03				0.60		
Uncontrolled Potential Emission in tons/yr	69,589	16,006	16,006	95,079	9,383	47	391
Limited Potential Emission in tons/yr	*521*	--	--	--	*10,425*	--	--

Note:
Limited NOx will be assumed to equal the Uncontrolled Potential emission, since using the limits set in the permit of 0.6 lb/MMBtu will give a higher number than the uncontrolled PTE for boiler 18.

Methodology
The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
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; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
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)
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Limited Emission Factor in lb/MMBtu * 8760hours/1year * 1ton/2000lbs

Uncontrolled HAP's

	Pollutant					
	HCl	HF	Benzene	Benzyl Chloride	Cyanide	Isophorone
Emission Factor in lb/ton	1.2E+00	1.5E-01	1.3E-03	7.0E-04	2.5E-03	5.8E-04
Potential Emission in tons/yr	938.3	117.3	1.0	0.5	2.0	0.5

Emission Factors from AP-42, Chapter 1.1 (Controlled Coal Combustion): Table 15, Hydrogen Chloride and Hydrogen Fluoride; Table 14, Var. Org. Comp.
Methodology:
Potential Emission in tons/yr = Emission Factor in lb/ton * Potential Througput (ton/yr) * 1ton/2000lbs

Uncontrolled HAP's

	Pollutant					
	As	Be	Cr	Pb	Mn	Ni
Emission Factor in lb/MMBtu	6.84E-04	8.10E-05	1.57E-03	5.07E-04	2.98E-03	1.29E-03
Potential Emission in lb/hour	2.71	0.32	6.23	2.01	11.82	5.12
Potential Emission in tons/yr	11.88	1.41	27.28	8.81	51.78	22.41

Emission Factors from AP-42, Chapter 1.1, Table 17: Trace Elements, Uncontrolled Bituminous Coal Combustion. (SCC 1-01-002-02/22)

Total HAPs	1211.34
Worst Single	938.3

Methodology:
Emission Factor in lb/MMBtu = Emission Factor lb/10^12Btu * 1TrillionBtu/1000000 MMBtu
Potential Emission in lb/hour = Emission Factor in lb/MMBtu * Heat Input Capacity (MMBtu/hour)
Potential Emission in tons/yr = Potential Emission in lb/hour * 8760hour/1year * 1ton/2000lbs

	Greenhouse Gases		
	CO_2	CH_4	N_2O
Emission Factor, lb/ton	4810	0.04	0.03
Potential Emission, ton/yr	3,760,956	31	23
Summed Potential Emissions, tons/yr	3,761,011		
Global Warming Potential (100 Year)	1	25	298
CO2e Total in tons/yr	3,768,728		

Methodology
Emission Factor (lb/ton) from AP 42 Tables 1.1-19 (PC-fired, dry bottom, wall fired (SCC 1-001-002-02/22)) and 1.1-20 (Subbituminous)
Pursuant to Table C-1 of 40 CFR Part 98 Subpart C, Bituminous coal has a default high heat value of 24.93 MMBtu/ton
Greenhouse Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Throughput (tons/yr) x Emission Factor (lb/ton)/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (21) + N2O Potential

Boilers: Pulverized Coal, Dry-Bottom, Wall-Fired Unit #18

Heat Input Capacity (MMBut/hr)	Heat Content of C	Potential Throughput (ton/yr)
3967	11111	1560000

Sulfur =	Weight % 3.2	Ash =	Weight % 8.90

Limited

	Pollutant (tons per year)					
	PM	PM10/PM2.5	SO2	NOx	VOC	CO
Emission Factor in lb/ton	0.7 (10A)	20.47 (2.3A)	3.6 *(38S)*	4.4	0.06	6.00
Potential Emission in tons/yr	524	16,006	2,852	3,475	47	4,691

Methodology
The PM emission factor is filterable PM only. The PM10 emission factor is filterable and condensable PM10 combined.
Heat content (11,111 Btu/lb) reported by source permittee as average value
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; pc, bit., dry-bot., wall-f'd., nsps: 1-01-002-02, 1-02-002-02 (9/98)
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: Emission Calculations
Natural Gas Combustion Only
Turbine 16A

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr	Sulfur Content %
1450.0	1020	12452.9	0.0036

Limited Potential Throughput MMCF/yr: 2843.1

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Uncontrolled Emission Factor in lb/MMBtu	0.0066	0.0066	0.0066	3.4E-03 *(0.94S)*	0.32	0.0021	0.0820
Uncontrolled Potential Emission in tons/yr	41.92	41.92	41.92	21.49	2032.32	13.34	520.78
Limited Potential Emission in tons/yr	*9.57*	*9.57*	*9.57*	*4.91*	*464.00*	*3.05*	*118.90*

*PM, PM10, and PM2.5 emission factors are condensable and filterable combined.
Emission Factors from AP 42, Chapter 3.1, Tables 3.1-1 and 3.1-2a

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760hours/1year x 1ton/2,000 lb
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Uncontrolled Emission Factor in lb/MMBtu * 2000hours/1year * 1ton/2000lbs

Hazardous Air Pollutants (HAPs)

	HAPs					
	Benzene	1, 3-Butadiene	Formaldehyde	Xylenes	Toluene	Propylene Oxide
Emission Factor in lb/MMBtu	1.2E-05	4.3E-07	7.10E-04	6.4E-05	1.3E-04	2.9E-05
Potential Emission in tons/yr	7.62E-02	2.73E-03	4.51E+00	4.06E-01	8.26E-01	1.84E-01
Limited Potential Emission in tons/yr	*1.74E-02*	*6.24E-04*	*1.03E+00*	*9.28E-02*	*1.89E-01*	*4.21E-02*

	HAPs						
	Acetaldehyde	Acrolein	Ethylbenzene	Naphthalene	PAH		
Emission Factor in lb/MMBtu	4.0E-05	6.4E-06	3.2E-05	1.3E-06	2.2E-06	Total HAPs	7.90
Potential Emission in tons/yr	2.54E-01	4.06E-02	2.03E-01	8.26E-03	1.40E-02	Worst Single	4.51
Limited Potential Emission in tons/yr	*5.80E-02*	*9.28E-03*	*4.64E-02*	*1.89E-03*	*3.19E-03*	*Limited Total*	*2.01*
						Limited Worst	*1.03*

Methodology is the same above.
Emission Factors from AP 42 Chapter 3.1, Table 3.1-3

Greenhouse Gases (GHGs)

	Greenhouse Gas				Limited Greenhouse Gas		
	CO2	CH4	N2O		CO2	CH4	N2O
Emission Factor in lb/MMBtu	110	0.0086	0.003	Emission Factor in lb/MMBtu	110	0.0086	0.003
Potential Emission in tons/yr	698,610	55	19	Limited Potential Emission in tons/yr	159,500	12	4
Summed Potential Emissions in tons/yr	698,684			Summed Potential Emissions in tons/yr	159,517		
CO2e Total in tons/yr	705,188			CO2e Total in tons/yr	161,002		

Methodology
Emission Factors are from AP 42, Table 3.1-2a
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) * 8760hrs/2,000 lb/ton
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (28) + N2O Potential Emission ton/yr x N2O GWP (265).

Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 200hours/yr /2000lb/ton

Appendix A: Emission Calculations
Natural Gas Combustion Only
Turbine 16B

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Heat Input Capacity MMBtu/hr	HHV mmBtu/mmscf	Potential Throughput MMCF/yr	Sulfur Content %
1450.0	1020	12452.9	0.0036

Limited Potential Throughput MMCF/yr: 2843.1

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMBtu	0.0066	0.0066	0.0066	3.4E-03 *(0.94S)*	0.32	0.0021	0.0820
Uncontrolled Potential Emission in tons/yr	41.92	41.92	41.92	21.49	2032.32	13.34	520.78
Limited Potential Emission in tons/yr	*9.57*	*9.57*	*9.57*	*4.91*	*464.00*	*3.05*	*118.90*

*PM, PM10, and PM2.5 emission factors are condensable and filterable combined.
Emission Factors from AP 42, Chapter 3.1, Tables 3.1-1 and 3.1-2a

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760hours/1year x 1ton/2,000 lb
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Emission Factor in lb/MMBtu * 2000hrs/1year * 1ton/2000lbs

Hazardous Air Pollutants (HAPs)

	HAPs					
	Benzene	1, 3-Butadiene	Formaldehyde	Xylenes	Toluene	Propylene Oxide
Emission Factor in lb/MMBtu	1.2E-05	4.3E-07	7.1E-04	6.4E-05	1.3E-04	2.9E-05
Potential Emission in tons/yr	7.62E-02	2.73E-03	4.51E+00	4.06E-01	8.26E-01	1.84E-01
Limited Potential Emission in tons/yr	*1.74E-02*	*6.24E-04*	*1.03E+00*	*9.28E-02*	*1.89E-01*	*4.21E-02*

	HAPs						
	Acetaldehyde	Acrolein	Ethylbenzene	Naphthalene	PAH		
Emission Factor in lb/MMBtu	4.0E-05	6.4E-06	3.2E-05	1.3E-06	2.2E-06	Total HAPs	7.90
Potential Emission in tons/yr	2.54E-01	4.06E-02	2.03E-01	8.26E-03	1.40E-02	Worst Single	4.51
Limited Potential Emission in tons/yr	*5.80E-02*	*9.28E-03*	*4.64E-02*	*1.89E-03*	*3.19E-03*	*Limited Total*	*2.01*
						Limited Worst	*1.03*

Methodology is the same above.
Emission Factors from AP 42 Chapter 3.1, Table 3.1-3

Greenhouse Gases (GHGs)

	Greenhouse Gas				Limited Greenhouse Gas		
	CO2	CH4	N2O		CO2	CH4	N2O
Emission Factor in lb/MMBtu	110	0.0086	0.003	Emission Factor in lb/MMBtu	110	0.0086	0.003
Potential Emission in tons/yr	698,610	55	19	Limited Potential Emission in tons/yr	159,500	12	4
Summed Potential Emissions in tons/yr	698,684			Summed Potential Emissions in tons/yr	159,517		
CO2e Total in tons/yr	705,188			CO2e Total in tons/yr	161,002		

Methodology
Emission Factors are from AP 42, Table 3.1-2a
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) * 8760hrs/yr * 1ton/2,000 lb
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (28) + N2O Potential Emission ton/yr x N2O GWP (265).
Limited Potential Emission in tons/yr = Heat Input Capacity (MMBtu/hr) * Emission Factor (lb/MMBtu) * 2000hours/1 year * 1ton/2000lbs

Appendix A: Emission Calculations
Gypsum Material Handling System
Radial Stackers

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Parameter		Value	Units	Source / Basis
New stacker throughput capacity	=	220	tons/hour	For each stacker. Information from the S&L Study 3-29-2012
New maximum throughput per stacker	=	1,927,200	tons/year	Based on 8,760 hours/year
Number of Stackers for Replacement	=	2		
Number of drop pont per stacker	=	1	Number	One drop point from stacker to pile
Moisture Content (M)	=	4.80	%	Conservative estimate
Annual Mean Wind speed (U)	=	10.00	mph	From RMS Calculations for Material Handling Emissions
PM Particle size multiplier (kP)	=	0.740	dimensionl	Ref. 1
PM10 Particle size multiplier (kP)	=	0.350	dimensionl	Ref. 1
PM2.5 Particle size multiplier (kP)	=	0.053	dimensionl	Ref. 1
PM Emission Factor	=	0.00171	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1
PM10 Emission Factor	=	0.00081	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1
PM2.5 Emission Factor	=	0.00012	lb/ton/drop	EF = (kP*0.0032)*(((U/5)^1.3)/(M/2)^1.4), Ref. 1

PTE Calculation Results

	PTE (TPY)		
Emission Unit	PM	PM10	PM2.5
Stacker 7MX04G-RS	1.65	0.78	0.12
Stacker 8MX04G-RS	1.65	0.78	0.12
Total	3.30	1.56	0.24

References:
1. EPA AP-42 Chapter 13.2.4; 11/2006.

Methodology:

PM/PM10/PM2.5 PTE (TPY) = New maximum throughput per stacker (tons/year) * Emission Factor (lb/ton/drop) * 1ton/2000lbs

Appendix A: Emission Calculations
Unit 17 & Unit 18
Activated Carbon Injection Grid

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Parameter		Value	Units	Source / Basis
Unit 17 AC Throughput Annual	=	365	tons/year	Design basis[1]
Unit 18 AC Throughput Annual	=	365	tons/year	Design basis[1]
PM Emission Factor	=	100%	fraction	AC particles in the 15 to 25 micrometer range[2]
PM10 Emission Factor	=	100%	fraction	Assumed 100% fractures to PM10[3]
PM2.5 Emission Factor	=	100%	fraction	Assumes 100% fractures to PM2.5[3]
Control Efficiency	=	99.75%		Use of ESP & Wet Scrubber[4]

PTE Calculation Results

	PTE, Controlled					
	Unit 17 (TPY)			Unit 18 (TPY)		
Emission Unit	PM	PM10	PM2.5	PM	PM10	PM2.5
ACI Stack Emissions	0.91	0.91	0.91	0.91	0.91	0.91

[1] Design basis establishes injection rate of ~2,000 pounds per day per unit.

[2] Activated Carbon Injection for Mercury Control on Industrial Coal-Fired Boilers Richard Miller Vice President Business Development ADA Environmental Solutions Co-Chairman ICAC Mercury Committee.

[3] Conservative assumption as worst case scenario.

[4] ESP design efficincies approximately 99.5%. Conservatively assumed that wet scrubber will achieve 50% additional reduction.

Appendix A: Emission Calculations
Units 17 and 18 Cooling Towers

Company Name: **NIPSCO LLC- R.M. Schahfer Generating Station**
Source Address: **2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.: **073-49556-00008**
Significant Permit Modification No: **073-49651-00008**
Reviewer: **Hachem Ismaili Alaoui**

TDS	1,150.0	ppm	
Total liquid drift	1.70	lb/1000 gal	From AP-42; Table 13.4-1
PM to PM10 ratio:	70%	% Drift PM	California SCAQMD CEIDARS Table
PM to PM2.5 ratio	42%	% Drift PM	California SCAQMD CEIDARS Table
Circulating Rate for Unit 17 Cooling Tower	145,000	gallons/minutes	
Circulating Rate for Unit 18 Cooling Tower	160,000	gallons/minutes	
Operation hours	8760	hours/year	

	Unit 17 Cooling Tower	Unit 18 Cooling Tower	Total
PM	74.50	82.20	**156.70**
PM10	52.15	57.54	**109.69**
PM2.5	31.29	34.53	**65.81**

Methodology
PM (tons/year) = Total Liquid Draft (lb/1000 gal) * (TDS (ppm) / 10^6) * Recirculation Rate (gpm) * 60 * 8760 (hour/year) * (1 ton /2000 lbs)

Appendix A: Emission Calculations
Fugitive Dust Emissions - Unpaved Roads

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Unpaved Roads at Industrial Site
The following calculations determine the amount of emissions created by unpaved roads, based on 8,760 hours of use and AP-42, Ch 13.2.2 (11/2006).

Vehicle Information (provided by source)

Type	Maximum number of vehicles	Number of one-way trips per day per vehicle	Maximum trips per day (trip/day)	Maximum Weight of Loaded Vehicle (tons/trip)	Total Weight driven per day (ton/day)	Maximum one-way distance (feet/trip)	Maximum one-way distance (mi/trip)	Maximum one-way miles (miles/day)	Maximum one-way miles (miles/yr)
Vehicle (entering plant) (one-way trip)	0.1	1.0	0.1	29.0	4.1	264	0.050	0.0	2.6
Vehicle (leaving plant) (one-way trip)	0.1	1.0	0.1	18.0	2.5	264	0.050	0.0	2.6
		Totals	**0.3**		**6.6**			**0.0**	**5.1**

Average Vehicle Weight Per Trip = 23.5 tons/trip
Average Miles Per Trip = 0.05 miles/trip

Unmitigated Emission Factor, Ef = k*[(s/12)^a]*[(W/3)^b] (Equation 1a from AP-42 13.2.2)

	PM	PM10	PM2.5	
where k =	4.9	1.5	0.15	lb/mi = particle size multiplier (AP-42 Table 13.2.2-2 for Industrial Roads)
s =	4.8	6.0	6.0	% = mean % silt content of unpaved roads (AP-42 Table 13.2.2-1 Iron and Steel Production)
a =	0.7	0.9	0.9	= constant (AP-42 Table 13.2.2-2 for Industrial Roads)
W =	23.5	23.5	23.5	tons = average vehicle weight
b =	0.45	0.45	0.45	= constant (AP-42 Table 13.2.2-2 for Industrial Roads)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor, Eext = E * [(365 - P)/365] (Equation 2 from AP-42 13.2.2)
Mitigated Emission Factor, Eext = E * [(365 - P)/365]
where P = 120 days of rain greater than or equal to 0.01 inches (see Fig. 13.2.2-1)

	PM	PM10	PM2.5	
Unmitigated Emission Factor, Ef =	6.51	2.03	0.20	lb/mile
Mitigated Emission Factor, Eext =	4.37	1.36	0.14	lb/mile
Dust Control Efficiency =				(pursuant to control measures outlined in fugitive dust control plan)

Process	Mitigated PTE of PM (Before Control) (tons/yr)	Mitigated PTE of PM10 (Before Control) (tons/yr)	Mitigated PTE of PM2.5 (Before Control) (tons/yr)
Vehicle (entering plant) (one-way trip)	0.01	0.00	0.00
Vehicle (leaving plant) (one-way trip)	0.01	0.00	0.00
Totals	**0.01**	**0.00**	**0.00**

Methodology
Total Weight driven per day (ton/day) = [Maximum Weight of Loaded Vehicle (tons/trip)] * [Maximum trips per day (trip/day)]
Maximum one-way distance (mi/trip) = [Maximum one-way distance (feet/trip) / [5280 ft/mile]
Maximum one-way miles (miles/day) = [Maximum trips per year (trip/day)] * [Maximum one-way distance (mi/trip)]
Average Vehicle Weight Per Trip (ton/trip) = SUM[Total Weight driven per day (ton/day)] / SUM[Maximum trips per day (trip/day)]
Average Miles Per Trip (miles/trip) = SUM[Maximum one-way miles (miles/day)] / SUM[Maximum trips per year (trip/day)]
Mitigated PTE (Before Control) (tons/yr) = (Maximum one-way miles (miles/yr)) * (Mitigated Emission Factor (lb/mile)) * (ton/2000 lbs)
Mitigated PTE (After Control) (tons/yr) = (Mitigated PTE (Before Control) (tons/yr)) * (1 - Dust Control Efficiency)

Abbreviations
PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
PM2.5 = Particulate Matter (<2.5 um)
PTE = Potential to Emit

Appendix A: Emission Calculations
Fugitive Dust Emissions - Paved Roads

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

Paved Roads at Industrial Site
The following calculations determine the amount of emissions created by paved roads, based on 8,760 hours of use and AP-42, Ch 13.2.1 (1/2011).

Vehicle Informtation (provided by source)

Type	Maximum number of vehicles per day	Number of one-way trips per day per vehicle	Maximum trips per day (trip/day)	Maximum Weight of Loaded Vehicle (tons/trip)	Total Weight driven per day (ton/day)	Maximum one-way distance (feet/trip)	Maximum one-way distance (mi/trip)	Maximum one-way miles (miles/day)	Maximum one-way miles (miles/yr)
Vehicle (entering plant) (one-way trip)	0.1	1.0	0.1	29.0	4.1	1056	0.200	0.0	10.2
Vehicle (leaving plant) (one-way trip)	0.1	1.0	0.1	18.0	2.5	1056	0.200	0.0	10.2
		Totals	**0.3**		**6.6**			**0.1**	**20.4**

Average Vehicle Weight Per Trip = 23.5 tons/trip
Average Miles Per Trip = 0.20 miles/trip

Unmitigated Emission Factor, Ef = [k * (sL)^0.91 * (W)^1.02] (Equation 1 from AP-42 13.2.1)

	PM	PM10	PM2.5	
where k =	0.011	0.0022	0.00054	lb/VMT = particle size multiplier (AP-42 Table 13.2.1-1)
W =	23.5	23.5	23.5	tons = average vehicle weight
sL =	9.7	9.7	9.7	g/m^2 = silt loading value for paved roads at iron and steel production facilities - Table 13.2.1-3)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor, Eext = E * [1 - (p/4N)] (Equation 2 from AP-42 13.2.1)
Mitigated Emission Factor, Eext = Ef * [1 - (p/4N)]
where p = 120 days of rain greater than or equal to 0.01 inches (see Fig. 13.2.1-2)
N = 365 days per year

	PM	PM10	PM2.5	
Unmitigated Emission Factor, Ef =	2.177	0.435	0.1069	lb/mile
Mitigated Emission Factor, Eext =	1.998	0.400	0.0981	lb/mile
Dust Control Efficiency =				(pursuant to control measures outlined in fugitive dust control plan)

Process	Mitigated PTE of PM (Before Control) (tons/yr)	Mitigated PTE of PM10 (Before Control) (tons/yr)	Mitigated PTE of PM2.5 (Before Control) (tons/yr)
Vehicle (entering plant) (one-way trip)	0.01	0.00	0.00
Vehicle (leaving plant) (one-way trip)	0.01	0.00	0.00
Totals	**0.02**	**0.00**	**0.00**

Methodology
Total Weight driven per day (ton/day) = [Maximum Weight of Loaded Vehicle (tons/trip)] * [Maximum trips per day (trip/day)]
Maximum one-way distance (mi/trip) = [Maximum one-way distance (feet/trip) / [5280 ft/mile]
Maximum one-way miles (miles/day) = [Maximum trips per year (trip/day)] * [Maximum one-way distance (mi/trip)]
Average Vehicle Weight Per Trip (ton/trip) = SUM[Total Weight driven per day (ton/day)] / SUM[Maximum trips per day (trip/day)]
Average Miles Per Trip (miles/trip) = SUM[Maximum one-way miles (miles/day)] / SUM[Maximum trips per year (trip/day)]
Unmitigated PTE (tons/yr) = [Maximum one-way miles (miles/yr)] * [Unmitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (Before Control) (tons/yr) = [Maximum one-way miles (miles/yr)] * [Mitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (After Control) (tons/yr) = [Mitigated PTE (Before Control) (tons/yr)] * [1 - Dust Control Efficiency]

Abbreviations
PM = Particulate Matter
PM10 = Particulate Matter (<10 um)
PM2.5 = Particle Matter (<2.5 um)
PTE = Potential to Emit

Appendix A: Emission Calculations
Reciprocating Internal Combustion Engines - Diesel Fuel
Output Rating (<=600 HP)
Maximum Input Rate (<=4.2 MMBtu/hr)

Company Name: NIPSCO LLC- R.M. Schahfer Generating Station
Source Address: 2723 East 1500 North, Wheatfield, IN 46392
Significant Source Modification No.: 073-49556-00008
Significant Permit Modification No: 073-49651-00008
Reviewer: Hachem Ismaili Alaoui

One (1) diesel fire pump 350 HP

Output Horsepower Rating (hp)	350.0
Maximum Hours Operated per Year	500
Potential Throughput (hp-hr/yr)	175,000

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	0.0022	0.0022	0.0022	0.0021	0.0310	0.0025	0.0067
Potential Emission in tons/yr	0.19	0.19	0.19	0.18	2.71	0.22	0.58

*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.

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
Potential Emission in tons/yr	5.71E-04	2.51E-04	1.75E-04	2.39E-05	7.23E-04	4.70E-04	5.67E-05	1.03E-04

***PAH = Polyaromatic Hydrocarbon (PAHs are considered HAPs, since they are considered Polycyclic Organic Matter)
****Emission factors in lb/hp-hr were calculated using emission factors in lb/MMBtu and a brake specific fuel consumption of 7,000 Btu/hp-hr (AP-42 Table 3.3-1).

Potential Emission of Total HAPs (tons/yr)	**2.37E-03**

Methodology
Emission Factors are from AP 42 (Supplement B 10/96) Tables 3.4-1 , 3.4-2, 3.4-3, and 3.4-4.

Potential Throughput (hp-hr/yr) = [Output Horsepower Rating (hp)] * [Maximum Hours Operated per Year]
Potential Emission (tons/yr) = [Potential Throughput (hp-hr/yr)] * [Emission Factor (lb/hp-hr)] / [2,000 lb/ton]

Green House Gas Emissions (GHG)

	Pollutant		
	CO2	CH4	N2O
Emission Factor in lb/hp-hr	1.15E+00	4.63E-05	9.26E-06
Potential Emission in tons/yr	1.01E+02	4.05E-03	8.10E-04

Summed Potential Emissions in tons/yr	**1.01E+02**
CO2e Total in tons/yr	**1.01E+02**

Methodology
Emission Factors are from AP42 (Supplement B 10/96), Tables 3.3-1 and 3.3-2
CH4 and N2O Emission Factor from 40 CFR 98 Subpart C Table C-2.
Global Warming Potentials (GWP) from Table A-1 of 40 CFR Part 98 Subpart A.
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]
CO2e (tons/yr) = CO2 Potential Emission ton/yr x CO2 GWP (1) + CH4 Potential Emission ton/yr x CH4 GWP (25) + N2O Potential Emission ton/yr x N2O GWP (298).

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100

Company Name: **NIPSCO LLC- R.M. Schahfer Generating Station**
Source Address: **2723 East 1500 North, Wheatfield, IN 46392**
Significant Source Modification No.: **073-49556-00008**
Significant Permit Modification No: **073-49651-00008**
Reviewer: **Hachem Ismaili Alaoui**

Actual Throughput for year 2023

MMCF/yr
115.0

	Pollutant							
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO	CO2e
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	37.1 **see below	5.5	37.7	119,349
Potential Emission in tons/yr	0.11	0.44	0.44	0.03	2.13	0.32	2.17	6862.56

*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 at 30 ppm for unit with FGR and CO at 50 ppm from vendor information.
CO2e from 40 CFR Part 98 Subpart A Table A-1 and Subpart C Tables C-1 and C-2.

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
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Indiana Department of Environmental Management
Office of Air Quality

Appendix B
Best Available Control Technology (BACT) Determination

Source Background and Description

Source Name:	Northern Indiana Public Services Company LLC - R.M. Schahfer Generating Station
Source Location:	2723 East 1500 North, Wheatfield, IN 46392
County:	Jasper
SIC Code:	4911 (Electric Services)
Permit No.:	073-49556-00008
Permit Reviewer:	Hachem Ismaili Alaoui

Background Information

The Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ) has performed the following Best Available Control Technology (BACT) review for the 2026 CCCT Project from Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station. The source submitted an application on January 17, 2024, relating to the construction and operation four (4) combined cycle combustion turbines, two (2) auxiliary boilers, two (2) mechanical draft cooling towers, one (1) natural gas-fired dew point heater, six (6) lube oil tanks with demister vents, two (2) diesel-fired emergency generators, two (2) diesel-fired fire pumps, and one (1) diesel storage tank.

Actual to Potential Applicability Test analysis shows VOC and GHGs exceed major source thresholds. Therefore, a PSD/BACT review is required for this source for VOC and GHGs.

Proposed New Emission Units

(a) Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a maximum rated capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a maximum rated heat input of 987 MMBtu per hour, using voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

(b) Two (2) natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, approved in 2026 for construction, each with a maximum rated capacity of 115 MMBtu per hour, using low NOx burners, and exhausting to stacks SAUX1 and SAUX2.

[Under 40 CFR 60, Subpart Db, these units are affected facilities]
[Under 40 CFR 63, Subpart DDDDD, these units are affected sources]

(c) One (1) natural gas-fired dew point heater, identified as DPH1, approved in 2026 for construction, with a maximum rated capacity of 28 MMBtu per hour, using no control, and exhausting to stack SDPH1.

[Under 40 CFR 60, Subpart Dc, this is an affected facility]
[Under 40 CFR 63, Subpart DDDDD, this is an affected source]

(d) Two (2) mechanical draft cooling towers, identified as CTH1 and CTH2, approved in 2026 for construction, each with a circulation rate of 280,000 gallons of water minute, TDS of 2,000 ppm, and total drift loss of 0.005%.

(e) Two (2) 2,500 kW diesel-fired certified emergency generators, identified as EDGCC1 and EDGCC2, approved in 2026 for construction, each with a maximum rated capacity of 3,353 hp, using no control, and exhausting to stacks SEDGCC1 and SEDGCC2.

[Under 40 CFR 60, Subpart IIII, these units are affected facilities]
[Under 40 CFR 63, Subpart ZZZZ, these units are affected sources]

(f) Two (2) 244 kW diesel-fired certified emergency fire pumps, identified as FPCC1 and FPCC2, approved in 2026 for construction, each with a maximum rated capacity of 327 hp, using no control, and to stacks SFPCC1 and SFPCC2.

[Under 40 CFR 60, Subpart IIII, these units are affected facilities]
[Under 40 CFR 63, Subpart ZZZZ, these units are affected sources]

(g) One (1) diesel storage tank, identified as TKCC1, approved in 2026 for construction, with a maximum storage capacity of 5,000 gallons and maximum throughput of 130,000 gallons per year, using no control, and exhausting outdoors.

(h) Six (6) lube oil demister vents, identified as LOV21A, LOV21B, LOV22A, LOV22B, LOV21S, and LOV22S, approved in 2026 for construction, each with a vent flow rate of 500 cfm.

(i) High Voltage Electric Switchgear Containing Sulfur Hexafluoride (SF6), identified as CCCT - Circuit Breakers, approved in 2026 for construction.

(j) Natural gas piping components, identified as CCCT - Piping Systems, approved in 2026 for construction, including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections.

Summary of the Best Available Control Technology (BACT) Process

BACT is an emissions limitation based on the maximum degree of pollution reduction of emissions, which is achievable on a case-by-case basis. BACT analysis takes into account the energy, environmental, and economic impacts on the source. These reductions may be determined through the application of available control techniques, process design, work practices, and operational limitations. Such reductions are necessary to demonstrate that the emissions remaining after application of BACT will not cause or contribute significantly to air pollution, thereby protecting public health and the environment.

Federal guidance on BACT requires an evaluation that follows a “top down” process. In this approach, the applicant identifies the best-controlled similar source on the basis of controls required by regulation or permit, or controls achieved in practice. The highest level of control is then evaluated for technical feasibility. The five (5) basic steps of a top-down BACT analysis are listed below:

Step 1: Identify Potential Control Technologies

The first step is to identify potentially "available" control options for each emission unit and for each pollutant under review. Available options should consist of a comprehensive list of those technologies with a potentially practical application to the emissions unit in question. The list should include lowest achievable emission rate (LAER) technologies, innovative technologies, and controls applied to similar source categories. Although innovative technologies may be included as a potentially available control option, there is no requirement in the State or Federal regulations to require innovative control to be evaluated in Step 1 or used as BACT.

Step 2: Eliminate Technically Infeasible Options

The second step is to eliminate technically infeasible options from further consideration. To be considered feasible, a technology must be both available and applicable. It is important in this step that any presentation of a technical argument for eliminating a technology from further consideration be clearly documented based on physical, chemical, engineering, and source-specific factors related to safe and successful use of the controls. Innovative control means a control that has not been demonstrated in a commercial application on similar units. Innovative controls are normally given a waiver from the BACT requirements due to the uncertainty of actual control efficiency. A control technology is considered available when there are sufficient data indicating that the technology results in a reduction in emissions of regulated pollutants.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern. The ranked alternatives are reviewed in terms of environmental, energy, and economic impacts specific to the proposed modification. If the analysis determines that the evaluated alternative is not appropriate as BACT due to any of the impacts, then the next most effective is evaluated. This process is repeated until a control alternative is chosen as BACT. If the highest ranked technology is proposed as BACT, it is not necessary to perform any further technical or economic evaluation, except for the environmental analyses.

Step 4: Evaluate the Most Effective Controls and Document the Results

The fourth step entails an evaluation of energy, environmental, and economic impacts for determining a final level of control. The evaluation begins with the most stringent control option and continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts.

For the technologies determined to be feasible, there may be several different limits that have been set as BACT for the same control technology. The permitting agency has to choose the most stringent limit as BACT unless the applicant demonstrates in a convincing manner why that limit is not feasible. BACT must, at a minimum, be no less stringent than the level of control required by any applicable New Source Performance Standard (NSPS) and National Emissions Standard for Hazardous Air Pollutants (NESHAP) or state regulatory standards applicable to the emission units included in the permits.

Step 5: Select BACT

The fifth and final step is to select as BACT the most effective of the remaining technologies under consideration for each pollutant of concern. For the technologies determined to be feasible, there may be several different limits that have been set as BACT for the same control technology. The permitting agency has to choose the most stringent limit as BACT unless the applicant demonstrates in a convincing manner why that limit is not feasible. The final BACT determination would be the technology with the most stringent corresponding limit that is economically feasible. BACT must, at a minimum, be no less stringent

than the level of control required by any applicable New Source Performance Standard (NSPS) and National Emissions Standard for Hazardous Air Pollutants (NESHAP) or state regulatory standards applicable to the emission units included in the permits. The Office of Air Quality (OAQ) makes final BACT determinations by following the five steps identified above.

Also, in accordance with the "Top-Down" Best Available Control Technology Guidance Document outlined in the 1990 draft U.S. EPA New Source Review Workshop Manual, BACT analyses take into account the energy, environmental, and economic impacts of the control options. Emission reductions may be determined through the application of available control techniques, process design, and/or operational limitations. Such reductions are necessary to demonstrate that the emissions remaining after application of BACT will not cause adverse environmental effects to public health and the environment.

BACT Analysis – Combined Cycle Combustion Turbines

Emission Unit Description

Four (4) natural gas fired combined cycle combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, each with a maximum rated capacity of 3,400 MMBtu per hour, each equipped with a heat recovery steam generator (HRSG) and duct burner with a maximum rated heat input of 987 MMBtu per hour, using voluntarily selective catalytic reductions (SCR21A, SCR21B, SCR22A, and SCR22B) for NOx control when operating in combined cycle mode, oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, and exhausting to stacks S21A, S21B, S22A, and S22B.

Unit 21A, Unit 21B, Unit 22A, and Unit 22B, approved in 2026 for construction, using oxidation catalysts (OXCA21A, OXCA21B, OXCA22A, and OXCA22B) for CO and VOC control, continuous emissions monitoring (CEMS) system for NOx, may also operate as simple cycle combustion turbines and exhaust to bypass stacks S21Asc, S21Bsc, S22Asc, and S22Bsc.

[Under 40 CFR 60, Subpart KKKK, these units are affected facilities]
[Under 40 CFR 60, Subpart TTTTa, these units are affected facilities]
[Under 40 CFR 63, Subpart YYYY, these units are affected sources]

VOC BACT Analysis – Combined Cycle Combustion Turbines

VOC emissions result from incomplete combustion. VOCs are released into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. VOC emissions are higher for gas turbines operating at low loads than for similar gas turbines operating at higher loads, as the former has decreased fuel combustion efficiency.

Step 1: Identify All Potentially Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable VOC control technologies for the generating units were identified based on the principles of control technology and engineering experience for general combustion units. The control technologies identified for VOC are presented below:

(1) Regenerative Thermal Oxidizer
(2) Recuperative Thermal Oxidizer
(3) Flare
(4) Oxidation Catalyst
(5) Good Combustion Practices

Regenerative Thermal Oxidizer

The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors. Upon passing through the flame, the waste gas containing VOC is heated. The mixture continues to react as it flows through the combustion chamber. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.

The required level of VOC destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000˚F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control.

A Regenerative Thermal Oxidizer incorporates heat recovery and greater thermal efficiency through the use of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords very high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the increased auxiliary fuel savings to make such a system economical.

Thermal oxidizers do not reduce emissions of VOC from properly operated natural gas combustion units without the use of a catalyst. In addition, oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases. Therefore, regenerative thermal oxidizers are not considered technically feasible.

Recuperative Thermal Oxidizer

This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1.200ºF and the waste stream inlet pollutants concentration is as low as 500 - 50,000 scfm.

Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.

Thermal oxidizers do not reduce emissions of VOC from properly operated natural gas combustion units without the use of a catalyst. Recuperative thermal oxidizers will also require additional fuel to reach the ignition temperature of the waste gas stream. In addition, oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases. Therefore, recuperative thermal oxidizers are not considered technically feasible.

Flare

Although the VOC concentration is very low, the stream flow rate is very high. The low heating value of the stream is too low for flaring. As there are insufficient organics in this vent stream to

support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NOx. Flares have not been utilized or demonstrated as a control device for VOC from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers. Therefore, flares are not considered technically feasible.

Oxidation Catalyst

Oxidation catalysts are used to increase the oxidation rate of VOCs in exhaust gases produced after fuel combustion. When the exhaust gas passes over the catalyst bed, oxygen and VOCs migrate to the catalyst surface by gas diffusion and are adsorbed onto the catalyst's active sites, where oxidation occurs. The oxidation reaction products are then desorbed from the active sites and transferred by diffusion back into the gas stream.

Effective reduction of VOC emissions in the exhaust gas depends on the temperature, flow rate, and oxidation catalyst efficiency. Oxidation catalysts work best at temperatures of 600 – 800 °F and have a maximum design exhaust temperature of 1000 – 1250 °F. The residence time required for oxidation to take place at the catalyst's active sites may not be achieved if air flow rates exceed the catalyst's design specifications, which typically range from 700 to 50,000 scfm. Particulate matter, sulfur, and other compounds may bind to the catalyst and cause fouling, which can decrease its efficiency over time.

Oxidation catalysts have been used in combustion turbines at other permitted facilities and are determined to be a technically feasible control option.

Good Combustion Practices

Good combustion practices involve operating the combustion turbines as efficiently as possible to reduce potential emissions. When operated at the appropriate oxygen range and temperature which promotes complete fuel combustion, VOC emissions will be reduced. Therefore, good combustion practices are technically feasible for the CTs.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizer Feasibility

AS discussed above, regenerative thermal oxidizers do not reduce VOC emissions from natural gas-fired units without the additional use of a catalyst. Because of this, the use of a regenerative thermal oxidizer on its own is considered to be technically infeasible. The RBLC search results concur with this finding, as none of the filtered results employ a regenerative thermal oxidizer.

Recuperative Thermal Oxidizer Feasibility

As with regenerative thermal oxidizers, recuperative thermal oxidizers must be used in conjunction with a catalyst in order to reduce VOC emissions from natural gas-fired units. Additionally, thermal oxidizers are not recommended for controlling gases that contain sulfur compounds due to the formation of corrosive gases. Therefore, a recuperative thermal oxidizer is considered to be technically infeasible for controlling VOC emissions.

Flare Feasibility

As discussed above, flares have not been used or demonstrated as a control technology for VOC from this type of combustion turbine. Additionally, a flare would have no additional control

compared to a thermal oxidizer. Therefore, a flare is considered to be technically infeasible for the combustion turbine at this source.

The remaining technologies are considered technically feasible and considered further.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The control effectiveness of all remaining control technologies are ranked below:

Control Device	VOC Control/Reduction (%)
Oxidation Catalyst	40 – 60%
Good Combustion Practices	Base Case

Step 4: Evaluate the Most Effective Controls and Document the Results

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Proposed: NIPSCO - Schahfer Generating Station	073-49556-00008 (Pending)	N/A	Four (4) Combined Cycle Combustion Turbines (3,400 MMBtu/hr, each)	**Control Method:** Oxidation Catalyst Good Combustion Practices **Emission Limit 1:** 1.0 ppmvd at 15% O2 without duct firing, excluding SU/SD for each CT 2.0 ppmvd at 15% O2 with duct firing, excluding SU/SD for each CT **Emission Limit 2:** 6.90 lb/hr in combined cycle mode without DB for each CT 15.40 lb/hr in combined cycle with DB for each CT 9.10 lb/hr in simple cycle mode for each CT **Emission Limit 3** 25.60 tons/12 months, during SU/SD
Simple Cycle Turbines				
Sycamore Riverside Energy LLC	153-47292-00062 (3/31/2025)	IN-0384	Four (4) Simple Cycle Turbine (240 MW) (GE 7FA.05 CT)	**Control Method:** Clean fuels Good Combustion Practices **Emission Limit :** 1.4 ppmvd @ 15% O2 **Short Term Limit :** 3.5 lb/hr
Energy Lone Star Station	177473, N316 (3/17/2025)	TX-0989	Simple Cycle Peaking Turbine (Mitsubishi M501JAC) (4,112 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good Combustion Practices **Emission Limit :** 1.0 ppmvd @ 15% O2
Jack County Generating Station	PSDTX1640,, GHGPSDTX240 (12/27/2024)	TX-0986	Three (3) Simple Cycle Turbine (Siemens V84.3) (180.2 MW)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 2.0 ppmvd @ 15% O2
Xcel Energy Blue Lake	13900010-105 (08/07/2024)	MN-0095	Simple Cycle Turbine 8 (174.10 MMBtu/hr)	**Control Method:** -- **Emission Limit 1:** 4.60 ppm 3-hr aveg as methane **Emission Limit 2:** 10.030 lb/hr 3-hr aveg as methane

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
FPEC, LLC Freestone Peakers Plant	173582, PSDTX1626, GHGPSDTX233 (06/13/2024)	TX-0975	Two (2) Simple Cycle Turbine (Siemens V84.3) (221 MW)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 2.0 ppmvd @ 15% O2
LBWL – Erikson Station	74-18D (12/20/2022)	MI-0454	Simple Cycle Turbine EUCTGSC1 (667 MMBtu/hr)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 5.00 lb/hr, except SU/SD, each
Nacero Penwell Facility	164137 PSDTX1594GHG PSD TX207 (11/17/2021)	TX-0933	Simple Cycle Combustion Turbine	**Control Method:** Oxidation Catalyst Good Combustion Practices use of gaseous fuel **Emission Limit 1:** 1.7 ppmvd
El Paso Electric Company - Newman Power Station	N284, PSDTX1090M1, GHGPSDTX199 (08/27/2021)	TX-0908	Simple Cycle Turbine (230 MW)	**Control Method:** Use of Natural gas Oxidation Catalyst Good Combustion Practices **Emission Limit :** 2.0 ppmvd
NRG Cedar Bayou LLC - Unit 5	160538, PSDTX1528, GHGPSDTX204 (03/17/2021)	TX-0915	Simple Cycle Turbine (1,661 MMBtu/hr)	**Control Method:** Oxidation Catalyst **Emission Limit 1:** 1.5 ppmvd 3-hr rolling
LBWL - Erickson Station	74-18A (01/07/2021)	MI-0447	Simple Cycle Combustion Turbine (667 MMbtu/hr)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 5 lb/hr, except during SU/SD
Alaska Gasoline Development - Liquefaction Plant	AQ1524CPT01 (08/13/2020)	AK-0085	Six (6) Simple Cycle Turbines (386 MMBtu/hr)	**Control Method:** Good Combustion Practices Burning Clean Fuels **Emission Limit 1:** 0.0022 lb/MMBtu (3-hr avg.)
LBWL – Erikson Station	74-18 (12/21/2018)	MI-0441	Simple Cycle Combustion Turbines (667 MMBtu/hr)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 5 lb/hr, except during SU/SD
Rio Bravo Pipeline Facility	140792, PSDTX1498, GHGPSDTX158 (12/17/2018)	TX-0851	Twelve (12) General Electric Frame 7EA (967 MMBtu/hr)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 2.00 ppmvd @ 15% O2
Venture Global - Calcasieu Pass LNG Project	PSD-LA-824 (07/10/2018)	LA-0331	Three (3) Simple Cycle Combustion Turbines (927 MMBtu/hr)	**Control Method:** Good Combustion Practices Proper Operation Proper Equipment Design **Emission Limit 1:** 1.40 ppmvd 3-hr avg.
Driftwood LNG Facility	PSD-LA-824 (07/10/2018)	LA-0349	Simple Cycle Combustion Turbines (20) (540 MMBtu/hr)	**Control Method:** Good Combustion Practices Use of low sulfur facility fuel gas **Emission Limit 1:** 0.0020 lb/MMBtu HHV
Southern Power Jackson County Generators	PSDTX1422 (01/26/2018)	TX-0833	Four (4) Simple Cycle Combustion Turbines (20) (920.0 MW)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 2.00 ppmvd

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Southwestern Public Service Company – Gaines Power Plant	135322, PSDTX1470 and GHGPSDT (04/28/2017)	TX-0819	Four (4) Simple Cycle Combustion Turbines (Siemens SGT65000F5) (227.5 MW)	**Control Method:** Good Combustion Practices Pipeline quality natural gas limited hours **Emission Limit 1:** 2.00 ppmvd @ 145% O2
Duke Energy Indiana, LLC – Vermillion Generating Station	165-36956-00022 (02/28/2017)	IN-0261	Simple Cycle Combustion Turbines (80.0 MW)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 17.60 lb/hr, each **Emission Limit 2:** 1.76 ton/12 months
Cameron LNG Facility	PSD-LA-766(M3) (02/17/2017)	LA-0316	Nine (9) Simple Cycle Combustion Turbines (1069 MMBtu/hr)	**Control Method:** Good Combustion Practices Natural Gas Fuel **Emission Limit 1:** 1.60 ppmvd @ 15% O2
Robinson Power Company LLC - Beech Hollow	63-00922D (12/27/2017)	PA-0314	Simple Cycle Turbine (2433 MMBtu/hr)	**Control Method:** -- **Emission Limit 1:** 1.30 ppmvd @15% O2
Puente Power	00013-370 (10/13/2016)	CA-1238	Gas Turbines (262.0 MW)	**Control Method:** -- **Emission Limit 1:** 2.00 ppmvd as methane 1hr @15% O2
Bayonnne Energy Center	12863-BOP150001 (08/26/2016)	NJ-0086	Simple Cycle Stationary Turbines (245 MMBtu/hr)	**Control Method:** Oxidation Catalyst Use of natural gas **Emission Limit 1:** 2.00 ppmvd @15% O2 3-hr rolling **Emission Limit 2:** 1.65 lb/hr aveg
Brazos Electric Cooperative Hill County Generating Facility	130051,PSDTX1450, GHGPSDTX131 (04/07/2016)	TX-0794	Four (4) Simple Cycle Turbine (171.0 MW)	**Control Method:** Premixing of fuel and air enhances combustion efficiency and minimizes emissions **Emission Limit 1:** 5.4 lb/hr
Apex Texas Power, LLC Neches Station	122401, PSDTX1428, GHGPSDTX111 (03/24/2016)	TX-0788	Simple Cycle Turbine (232.0 MW)	**Control Method:** Good Combustion Practices Natural Gas Fuel **Emission Limit 1:** 2.00 ppm
Magnolia LNG Facility	PSD-LA-792 (03/21/2016)	LA-0307	Eight (8) Gas Turbines (333.0 MMBtu/hr)	**Control Method:** Good Combustion Practices Natural Gas Fuel **Emission Limit 1:** --
PSEG Fossil LLC Sewaren Generating Station	18068/BOP150001 (03/10/2016)	NJ-0084	One (1) Simple Cycle Combustion Turbine without Duct burner (3219 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good Combustion Practices **Emission Limit 1:** 1.00 ppmvd @ 15% O2 3-hr rolling **Emission Limit 2:** 4.410 lb/hr aveg

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Nacogdoches Power, LLC Nacogdoches Power Electric Generating Plant	77679, PSDTX1061M1 & O-3455 (10/14/2015)	TX-0764	One (1) Simple Cycle Turbine (232 MW)	**Control Method:** Good Combustion Practices Pipeline quality natural gas limited hours **Emission Limit 1:** 2.00 ppmvd @ 15% O2
Shawnee Energy Center, LLC Shawnee Energy Center	PSDTX1442, 125963 (10/09/2015)	TX-0768	Four (4) Simple Cycle Turbines (230 MW)	**Control Method:** Good Combustion Practices Pipeline quality natural gas limited hours **Emission Limit 1:** 1.40 ppmvd
Golden Spread Electric Cooperative, INC. Antelope Elk Energy Center	109148, PSDTX1358M1 (05/12/2015)	TX-0733	Three (3) Simple Cycle Turbines (202.0 MW)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 2.00 ppmvd @ 15% O2
Combined Cycle Turbines				
Duke Energy Cayuga Station	165-47430-00001 (02/14/2025)	IN-0382	Two (2) Combined Combustion Turbines (6A and 6B) (4254 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good Combustion Practices **Emission Limit 1:** 1.00 ppmvd @ 15% O2 3-hr avg w/o DB, except SU/SD **Emission Limit 2:** 2.00 ppmvd @ 15% O2 3-hr avg with DB, except SU/SD
Maple Creek Energy LLC	T153-45909-00056 (6/19/2023)	IN-0365	Combined Cycle Combustion Turbine CTGA (Siemens Model) (3800 MMBtu/hr)	**Control Method:** Oxidation Catalyst **Emission Limit 1:** 0.0015 lbs/MMBtu **Emission Limit 2:** 1.0 ppmvd at 15% O2 3-hr avg **Emission Limit 3:** 23.00 ton/yr for duration of combined SU/SD events
			Combined Cycle Combustion Turbine CTGB (GE Model) (4200 MMBtu/hr)	**Control Method:** Oxidation Catalyst **Emission Limit 1:** 0.0013 lbs/MMBtu **Emission Limit 2:** 1.0 ppmvd at 15% O2 3-hr avg **Emission Limit 3:** 18.00 ton/yr for duration of combined SU/SD events
Entergy Texas, Inc. (Orange County Advanced Power Station)	166032 PSDTX1598 GHGPSDTX210 (03/13/2023)	TX-0939	Combined Cycle Turbines (1215 MW)	**Control Method:** Oxidation Catalyst Good Combustion Practices **Emission Limit:** 2.0 ppmvd at 15% O2, with DB, 3-hr avg
Midland Cogeneration Venture Limited Partnerhip	10-23 (02/01/2023)	MI-0455	Combined Cycle Turbine EUCTGHRSG1 (4197.6 MMBtu/hr)	**Control Method:** Oxidation Catalyst **Emission Limit 1:** 2.40 ppm ppmvd @ 15% O2 1-hr avg, except SU/SD **Emission Limit 2:** 11.40 lb/hr, except SU/SD

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
LBWL – Erikson Station	74-18D (12/20/2022)	MI-0454	Combined Cycle Turbines EUCTGHRSG1 and EUCTGHRSG2 (667 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good Combustion Practices **Emission Limit 1:** 3.00 ppm ppmvd @ 15% O2, except SU/SD, each **Emission Limit 2:** 5.00 lb/hr, except SU/SD, each
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (7/29/22)	IL-0133	Two (2) Combined Cycle Combustion Turbine (3,647 MMBtu/hr, each)	**Control Method:** Oxidation catalyst good combustion practices **Emission Limit 1:** 1.00 ppmv @ 15% O2, 3-hr, without DB **Emission Limit 2:** 2.00 ppmv @ 15% O2, 3-hr, with DB **Emission Limit 3:** 56 lb/hr, during cold start 48 lb/hr, during non-cold start 44 lb/hr during shutdown
Alaska Gasoline Development Corporation – Liquefaction Plant	AQ1539CPT01 (07/07/2022)	AK-0088	Four (4) Simple Cycle Turbines (384 MMBtu/hr, each)	**Control Method:** Oxidation Catalyst Good Combustion Practices **Emission Limit 1:** 2.00 ppmvd @ 15% O2, 3-hr
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Combined Cycle Combustion Turbine EUCTGHRSG (North Plant) (3064 MMBtu/hr; 500 MW)	**Control Method:** Oxidation Catalyst Good Combustion Practices **Emission Limit 1:** 2.00 ppmvd @ 15% O2, excluding SU/SD
Marshall Energy Center, LLC - MEC North, LLC	168-17B (06/23/2022)	MI-0452	Combined Cycle Combustion Turbine EUCTGHRSG (South Plant) (3064 MMBtu/hr; 500 MW)	**Control Method:** Oxidation Catalyst Good Combustion Practices **Emission Limit 1:** 2.00 ppmvd @ 15% O2, excluding SU/SD
Magnolia Power LLC - Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Combined Cycle Combustion Turbine EQT001 (5081 MMBtu/hr; 730 MW)	**Control Method:** Oxidation Catalyst Good Combustion Practices **Emission Limit 1:** 1.00 ppmvd @ 15% O2, 3 1-hr avg without DB **Emission Limit 2:** 2.00 ppmvd @ 15% O2, 3 1-hr avg
Mountain State Clean Energy, LLC - Maidsville	R14-0038 (1/05/2022)	WV-0033	Two (2) Combined Combustion Turbine & Duct Burner (CT-01/HRSG1 and CT-02/HRSG2) (1275 MW)	**Control Method:** Oxidation catalyst Good combustion practices **Emission Limit 1:** 1.00 ppmdv @ 15% O2, 3 & 1-hr without DB, excluding SU/SD) **Emission Limit 2:** 2.00 ppmdv at 15% O2, 3 & 1-hr with DB, excluding SU/SD **Emission Limit 3:** 11.19 lb/hr avg of 3 & 1-hr

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Renovo Energy Center LLC - Renovo Plant	18-00033B (04/29/2021)	PA-0334	Two (2) Combined Combustion Turbines & Duct Burners (4546 MMBtu/hr, each)	**Control Method:** Oxidation catalyst SCR **Emission Limit 1:** 1.60 ppmdv @ 15% O2, 1-h rolling, without DB, each **Emission Limit 2:** 9.3 lb/hr, each
NRG Cedar bayou LLC - Unit 5	160538, PSDTX1528, GHGPSDTX204 (03/17/2021)	TX-0915	Combined Combustion Turbine	**Control Method:** Oxidation catalyst **Emission Limit 1:** 1.00 ppmdv @ 15% O2, without DB, 3-h rolling
Lansing Board of Water and Light LBWL - Erickson Station	74-18A (01/07/2021)	MI-0447	Two (2) Combined Combustion Turbines EUCTGHRSG1 and EUCTGHRSG2 (667 MMBtu/hr, each)	**Control Method:** Oxidation catalyst Good combustion practices **Emission Limit 1:** 3.00 ppmdv @ 15% O2, 1-hr rolling, with DB, excluding SU/SD, each **Emission Limit 2:** 5.00 lb/hr 1-hr rolling, during SU/SD, each
Panda Stonewall LLC	73826-6 (12/18/2020)	VA-0335	Two (2) Combined Combustion Turbines	**Control Method:** Oxidation catalyst **Emission Limit 1:** 1.50 ppmdv @ 15% O2 during normal operation, without DB
Alabama Power Company - Plant Barry	503-1001 (11/09/2020)	AL-0328	Two (2) Combine Combustion Turbines (744 MW)	**Control Method:** SCR Oxidation Catalyst **Emission Limit:** 13.6 lb/hr, 3-hr average **Emission Limit 2:** 0.003 lb/MMBtu, 3-hr average
Nemadji Trail Energy Center	18-MMC-168 (09/01/2020)	WI-0300	Natural Gas Combined CycleTurbine (P01) (4,671 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 2.7 ppm @ 15% O2 with DB **Emission Limit 2:** 0.60 ppm @ 15% O2 without DB **Emission Limit 3:** 950.00 lb/start up **Emission Limit 4:** 40.00 lb/shutdown
	While the proposed combustion turbine at Nemadji Trail Energy Center has been determined to meet a VOC limit of 0.60 ppm @ 15% O2 without duct burner using an oxidation catalyst, this source has not been constructed. This permit has been revoked and this source has not been constructed. Therefore, this limit has not been demonstrated in practice.			
FG LA Complex	PSD-LA-812 (01/06/2020)	LA-0364	Cogeneration Units (2222 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 4.00 ppmvd @ 15% O2
Indeck Niles, LLC	75-16B (11/26/2019)	MI-0445	Combined Cycle Turbines (3,421 MMBtu/hr)	**Control Method:** Good combustion practices Inlet air conditioning

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
				Pipeline quality natural gas **Emission Limit 1:** 4.0 ppm ppmvd @15% O2, each
Thomas Township Energy, LLC	210-18 (8/21/2019)	MI-0442	Combined Cycle Turbine (625 MW; 4,200 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 0.0040 lb/MMBtu, without DB, except during SU/SD **Emission Limit 2:** 377 tons/12 months
Cogen Tech Linden Venture LP	41809 / BOP170001 (07/30/2019)	NJ-0088	Combined Cycle Turbine (21042 MMBtu/yr; 250 MW)	**Control Method:** Oxidation Catalyst Use of natural gas **Emission Limit 1:** 3.20 lb/hr **Emission Limit 2:** 1.00 ppmvd @ 15% O2, without DB, 3-hrs rolling
Chickahominy Power LLC	52610-1 (6/24/2019)	VA-0332	Three (3) Combined Cycle Combustion Turbines (4,066 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 0.70 ppmvd @ 15% O2, w/o DB **Emission Limit 2:** 68.10 tons/12 months **Emission Limit 3:** 216.00 lb/turbine/event, cold start **Emission Limit 4:** 216.00 lb/turbine/event, warm start
	The Chickahominy Power project in Virginia has a permitted VOC BACT limit of 0.70 ppmvd @ 15% O2 without duct firing. While this limit is less than the proposed BACT limit for NIPSCO, the Chickahominy project has been cancelled.			
Lansing Board of Water and Light LBWL - Erickson Station	74-18 (12/21/2018)	MI-0441	Two (2) Combined Cycle Combustion Turbines (667 MMBtu/hr, each)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 3.00 ppmvd @ 15% O2 in combined mode, except during SU/SD **Emission Limit 2:** 5.00 lb/hr in HRSG bypass mode, except during SU/SD
Venture Global Calcasieu Pass LNG Project	PDS-LA-805 (09/21/2018)	LA-0331	Five (5) Combined Cycle Combustion Turbines (CCCT1 to CCCT5) (921 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good combustion practices Proper Equipment Design **Emission Limit 1:** 1.10 ppmvd @ 15% O2 3-hr avg during normal operations w/o DB
ESC Brooke County Power I, LLC Brooke County Power Plant	R14-0035 (9/18/2018)	WV-0032	Combined-cycle Turbine (2,737.7 MMBtu/hr; 462.5 MW)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 8.10 lb/hr **Standard Emission Limit:** 2.00 ppmvd @ 15% O2, with DB

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
APV Renaissance Partners Renaissance Energy Center	30-00235A (8/27/2018)	PA-0319	Combined Cycle Combustion Turbine (2,665.9 MMBtu/hr)	**Control Method:** Oxidation Catalyst **Emission Limit 1:** 1.00 ppmdv @ 15% O2 w/o DB **Emission Limit 2:** 55.240 tons/yr without DB
New Covert Generating Facility	186-17 (07/30/2018)	MI-0432	Three (3) Combined Cycle Combustion Turbines (1230 MW)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 1.00 ppmdv @ 15% O2, without DB, excluding SU/SD **Emission Limit 2:** 48.00 ton/12 months
DTE Electric Company Belle River Combined Cycle Power Plant	19-18 (07/16/2018)	MI-0435	Two (2) Combined Cycle Combustion Turbines	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 0.0026 lb/MMBtu, each, except during SU/SD **Emission Limit 2:** 0.0026 lb/MMBtu without DB, each, except during SU/SD
Marshall Energy Central LLC - MEC North, LLC and MEC South, LLC	167-17 AND 168-17 (06/29/2018)	MI-0433	Two (2) Combined Cycle Combustion Turbines (South Plant and North Plant) (500 MW)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 4.00 ppmvd @ 15% O2, except SU/SD, each.
Novi Energy C4GT, LLC	52588 (04/26/2018)	VA-0328	GE Combustion Turbine with HRSG (3,482 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 0.70 ppmvd at 15% O2 3-hr avg, without DB **Emission Limit 2:** 1.40 ppmvd at 15% O2 3-hr avg, with DB **Emission Limit SU/SD 1:** 60.00 lb/event cold start 60 min or less
			Siemens Combustion Turbine with HRSG (3,116 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 1.00 ppmvd at 15% O2 3-hr avg, without DB **Emission Limit 2:** 2.00 ppmvd at 15% O2 3-hr avg, with DB **Emission Limit SU/SD 1:** 37.00 lb/event cold start 55 min or less **Emission Limit SU/SD 2:** 34.00 lb/event cold start 55 min or less

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
	The Novi Power project in Virginia proposed to use an oxidation catalyst and has two proposed turbine vendors, GE and Siemens. The GE turbine has VOC limits of 1.40 ppmvd without duct firing and 0.70 ppmvd with duct firing. The Siemens turbine has VOC limits of 1.00 ppmvd without duct firing and 2.00 ppmvd with duct firing. This illustrates that the same control technology (oxidation catalyst) can result in two different emission rates due to differences in turbine technology. It is not unusual to have small differences in emissions for different turbine technologies, and for turbine vendors to adjust their estimated emissions as 25 more of their turbines come into service. As such, the Novi Power BACT determination is consistent with the proposed BACT limit proposed by NIPSCO.			
Harrison Power	P0122266 (4/19/2018)	OH-0377	GE Combustion Turbines (P005 and P006) (3459.6 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 4.36 lb/hr with DB, except SU/SD **Emission Limit 2:** 49.10 ton/ 12 months, including SU/SD **Standard Emission Limit:** 2.00 ppmvd @ 15% O2, without DB
			Mitsubishi/Hitachi Combustion Turbines (P007 and P008) (3231 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 9.80 lb/hr with DB, except SU/SD **Emission Limit 2:** 84.70 ton/ 12 months, including SU/SD **Standard Emission Limit:** 2.00 ppmvd @ 15% O2, without DB
Entergy Texas Inc - Montgomery County Power Station	N256, PSDTX1510, and GHGPSDTX1 (03/30/2018)	TX-0834	Combined Cycle Turbine (2,635 MMBtu/hr)	**Control Method:** Oxidation Catalyst **Emission Limit 1:** 2.0 ppmvd at 15% O2, without DB, 3-hr average
ESC Harrison County Power Plant	R14-0036 (03/27/2018)	WV-0029	Combined Cycle Turbine (3,496.2 MMBtu/hr; 640 MW)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 11.40 lb/hr with DB **Emission Limit 2:** 54.80 ton/ 12 months **Standard Emission Limit:** 2.00 ppmvd @ 15% O2, with DB
Seminole Electric Cooperative, Inc - Seminole Generating Station	1070025-028-AC / PSD-FL-443 (03/21/2018)	FL-0364	Combined Cycle Turbine (3,514 MMBtu/hr; 415 MW)	**Control Method:** Oxidation Catalyst **Emission Limit 1:** 1.00 ppmvd @ 15% O2 without DB **Emission Limit 2:** 2.00 ppmvd @ 15% O2 with DB
Renovo Energy Center, LLC	18-00033A (01/26/2018)	PA-0316	Combined Cycle Turbine (500 MW)	**Control Method:** -- **Emission Limit 1:** 1.00 ppmvd @ 15% O2, without DB **Emission Limit 2:** 31.050 ton/yr

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Florida Power and Light Company Dania Beach Energy Center	0110037-017-AC (12/04/2017)	FL-0363	Combined Cycle Turbine Unit (GE 7HA) (4000 MMBtu/hr)	**Control Method:** Use of clean fuels **Emission Limit 1:** 1.00 ppmvd @ 15% O2, without DB
Long Ridge Energy Generation LLC - Hannibal Power Long Ridge Energy	P0122829 (11/07/2017)	OH-0375	GE Combustion Turbine (P004) (3,544 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 4.54 lb/hr excluding SU/SD **Emission Limit 2:** 26.40 ton/12 months, including SU/SD **Standard Emission Limit:** 1.00 ppmvd at 15% O2, without DB 78.1 lb/hr during cold startup. 11.5 lb/hr during hot startup, 12.0 lb/hr during warm startup, 29.6 lb/hr during shutdown.
			Mitsubishi Combustion Turbine (P005) (3320 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 8.80 lb/hr with DB excluding SU/SD **Emission Limit 2:** 79.30 ton/12 months, including SU/SD **Standard Emission Limit:** 2.00 ppmvd at 15% O2, with DB 224.7 lb/hr during cold startup. 185.9 lb/hr during hot startup, 225.1 lb/hr during warm startup, 97.0 lb/hr during shutdown.
			Siemens Combustion Turbine (P006) (3602 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 9.50 lb/hr with DB excluding SU/SD **Emission Limit 2:** 50.80 ton/12 months, including SU/SD **Standard Emission Limit:** 2.00 ppmvd at 15% O2, with DB 40.4 lb/hr during cold startup. 40.7 lb/hr during hot startup, 40.2 lb/hr during warm startup, 39.4 lb/hr during shutdown.
Guernsey Power Station LLC	P0122594 (10/23/2017)	OH-0374	Three (3) Combined Cycle Combustion Turbines (P001 - P002) (3,516 MMBtu/hr; 1,650 MW)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 11.73 lb/hr with DB, excluding SU/SD **Emission Limit 2:** 4.92 lb/hr without DB, excluding SU/SD **Standard Emission Limit:** 2.00 ppmvd at 15% O2, with DB 55.9 lb/cold startup,

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
				13.7 lb/hot startup, 16.5 lb/warm startup, 34.9 lb/shutdown, 146.91 ton/12 months for 3 turbines
Oregon Energy Center	P0121049 (09/27/2017)	OH-0372	Combined Cycle Combustion Turbines (P001 and P002) (3,055 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 8.80 lb/hr with DB, excluding SU/SD **Emission Limit 2:** 50.28 ton/12 months, normal operation including SU/SD **Standard Emission Limit:** 2.00 ppmvd at 15% O2, with DB 64.4 lb/hr during cold startup, 60.1 lb/hr during hot startup, 59.6 lb/hr during warm startup, 62.8 lb/hr during shutdown
Trumbull Energy Center	P0122331 (09/07/2017)	OH-0370	Combined Cycle Turbine (P001 and P002) (3025 MMBtu/hr; 940 MW)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 8.80 lb/hr with DB, except SU/SD 4.10 lb/hr without DB, except SU/SD **Emission Limit 2:** 50.30 ton/12 months, normal operation including SU/SD **Standard Emission Limit:** 2.00 ppmvd at 15% O2, with DB 64.4 lb/hr during cold startup, 60.1 lb/hr during hot startup, 59.6 lb/hr during warm startup, 67.9 lb/hr during shutdown
NTE Connecticut, LLC Killingly Energy Center	089-0107 (06/30/2017)	CT-0161	Combustion Turbine with DB (2639 MMBtu/hr)	**Control Method:** Oxidation Catalyst **Emission Limit 1:** 1.60 ppmvd @ 15% O2, with DB
			Combustion Turbine without DB (2969 MMBtu/hr)	**Control Method:** Oxidation Catalyst **Emission Limit 1:** 0.70 ppmvd @ 15% O2, without DB
	The Killingly Energy Center in Connecticut proposed to use an oxidation catalyst and has a VOC limit of 0.70 ppmvd without duct firing and a VOC limit of 1.60 ppmvd with duct firing. The project is proposed to be located in a non-attainment area for ozone; therefore, this is a LAER determination and should not be considered BACT.			
Southwestern Public Service Company Gaines County Power Plant	135322, PSDTX1470, AND GHGPSDT (04/28/2017)	TX-0819	Combined Cycle Turbine with HRSG (426 MW)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 3.50 ppmvd @ 15% O2
Hilltop Energy Center, LLC	30-00233B (04/12/2017)	PA-0315	Combustion Cycle Turbine with duct burner (4,367 MMBtu/hr)	**Control Method:** -- **Emission Limit 1:** 2.00 ppmvd @ 15% O2, with DB

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
			Combustion Cycle Turbine without duct burner (4,367 MMBtu/hr)	**Control Method:** -- **Emission Limit 1:** 1.00 ppmvd @ 15% O2, without DB **Emission Limit 2:** 59.31 ton/yr
INEOS USA LLC - Chocolate Bayou Steam Generating (CBSG) Station	123117, PSDTX1460, GHGPSDTX135 (02/17/2017)	TX-0817	Combustion Cycle Cogeneration (50 MW)	**Control Method:** Oxidation Catalyst **Emission Limit 1:** 1.00 ppmvd @ 15% O2, without DB
Indeck Niles, LLC	75-16 (01/04/2017)	MI-0423	Two (2) Combustion Cycle Turbine (3421 MMBtu/hr, each)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 4.00 ppmvd @ 15% O2
Holland Board of Public Works - East 5th Street	107-13C (12/05/2016)	MI-0424	Two (2) Combustion Cycle Turbine (554 MMBtu/hr, each)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 4.00 ppmvd @ 15% O2 635 hrs/yr for SU/SD
South Field Energy, LLC	P0119495 (09/23/2016)	OH-0367	Two (2) Combined Cycle Combustion Turbines (3,131 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 10.64 lb/hr with DB, except SU/SD 4.35 lb/hr without DB, except SU/SD **Emission Limit 2:** 50.60 ton/yr, including SU/SD **Standard Emission Limit:** 2.00 ppmvd @ 15% O2 with DB 1.00 ppmvd @ 15% O2 w/o DB 21.4 lb/hr during startup, 55.2 lb/hr during shutdown
CPV Fairview Energy Center	11-00536A (09/02/2016)	PA-0310	Combustion Turbine and HRSG without DB	**Control Method:** -- **Emission Limit 1:** 1.00 ppmvd @ 15% O2 w/o DB
			Combustion Turbine and HRSG with DB (3338 MMBtu/hr)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 1.50 ppmvd @ 15% O2 w/o DB **Emission Limit 2:** 64.20 ton/ 12 months
Energy Louisiana, LLC - St. Charles Power Station	PSD-LA-804 (08/31/2016)	LA-0313	Two (2) Combined Cycle Combustion Turbines (3625 MMBtu/hr; 980 MW)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 61.27 lb/hr **Emission Limit 2:** 226.16 ton/yr **BACT Limit:** 2.00 ppmvd @ 15% O2, with DB, except SU/SD

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Stonegate Power, LLC - Middlesex Energy Center, LLC	19149/PCP150001 (07/19/2016)	NJ-0085	Combined Cycle Combustion Turbine with Duct Burner (633 MW)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 2.00 ppmvd @ 15% O2, with DB **Emission Limit 2:** 10.30 lb/hr
			Combined Cycle Combustion Turbine without Duct Burner (633 MW)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 1.00 ppmvd @ 15% O2, w/o DB **Emission Limit 2:** 4.37 lb/hr
Virginia Electric and Power Company - Greensville Power Station	52525 (06/17/2016)	VA-0325	Three (3) Combined Cycle Combustion Turbines with Duct Burner (3227 MMBtu/hr; 1,600 MW)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 1.40 ppmvd @ 15% O2, w/o DB **Emission Limit 2:** 214.80 ton/12 months
Apex Texas Power LLC - Neches Station	122401, PSDTX1428, GHGPSDTX111 (03/24/2016)	TX-0788	Two (2) Combustion Turbines (231 MW)	**Control Method:** Oxidation Catalyst **Emission Limit 1:** 2.00 ppmvd @ 15% O2, with DB
Florida Power & Light Okeechobee Clean Energy Center	0930117-001-AC (03/09/2016)	FL-0356	Three (3) Combined Cycle Combustion Turbine (3096 MMBtu/hr; 1,600 MW)	**Control Method:** Complete Combustion Minimizes VOC **Emission Limit 1:** 1.00 ppmvd @ 15% O2, w/o DB **Emission Limit 2:** 2.00 ppmvd @ 15% O2, with DB
Decordova II Power Company, LLC - Decordova Steam Electric Station	107569 AND PSDTX1432 (03/08/2016)	TX-0789	Two (2) Combined Cycle Combustion Turbines (231 MW)	**Control Method:** Oxidation Catalyst **Emission Limit 1:** 2.00 ppmvd @ 15% O2, with DB
Tenaska PA Partners, LLC - Westmoreland Generating Station	65-00990 C/E (02/12/2016)	PA-0306	Two (2) Combined Cycle Combustion Turbines (930 MW)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 2.40 ppmvd @ 15% O2 with DB **Emission Limit 2:** 9.4 lb/hr with DB
Lackawanna Energy Center, LLC - CTR/Jessup	35-00069A (12/23/2015)	PA-0309	Three (3) Combustion Turbines with duct burner (1,500 MW)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 1.50 ppmvd @ 15% O2, w/o DB **Emission Limit 2:** 24.6 ton/yr
			Three (3) Combustion Turbines without duct burner (1,500 MW)	**Control Method:** Oxidation Catalyst Good combustion practices **Emission Limit 1:** 1.00 ppmvd @ 15% O2
CPV Towantic, LLC	144-0023 (11/30/2015)	CT-0157	Combined Cycle Combustion Turbine (805 MW)	**Control Method:** Oxidation Catalyst **Emission Limit 1:** 1.00 ppmvd @ 15% O2 without DB

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
				Emission Limit 2: 2.00 ppmvd @ 15% O2 with DB
CPV Towantic, LLC	144-0024 (11/30/2015)	CT-0158	Combined Cycle Combustion Turbine (805 MW)	**Control Method:** Oxidation Catalyst **Emission Limit 1:** 1.00 ppmvd @ 15% O2 without DB **Emission Limit 2:** 2.00 ppmvd @ 15% O2 with DB
FGE Eagle Pines, LLC - Project	131316, PSDTX1454, And GHGPSDT (11/04/2015)	TX-0773	Three (3) Combined Cycle Turbines (321 MW)	**Control Method:** Oxidation Catalyst **Emission Limit 1:** 2.00 ppmvd @ 15% O2, with DB
Lon C. Hill, L.P. - Power Station	114911 AND PSDTX1380 (10/02/2015)	TX-0767	Two (2) Combined Cycle Turbines (195 MW)	**Control Method:** Oxidation Catalyst **Emission Limit 1:** 2.00 ppmvd @ 15% O2, with DB

Table above is a summary of last ten (10) years VOC emission limits for large natural gas-fired electric generating simple cycle and combined cycle *CTs* from the U.S. EPA's RACT/BACT/LAER ("RBLC") database and from recently issued permits. Emission limits include limits stated in pounds per hour, pounds per million Btu of heat input, and parts per million on a dry volume basis, corrected to 15% excess oxygen (ppmvd @ 15% O2).

The proposed generating units are not subject to any NSPS or NESHAP standard for VOC that could serve as a floor of allowable VOC BACT limits. The most stringent RBLC and permit entries for VOC control are provided in table above. The emission limits determined to constitute BACT for natural gas-fired combustion turbines generating units within the last ten (10) years vary both in emission levels and averaging periods. As shown, the VOC BACT emission limit varies from a minimum of 0.70 ppmvd at 15 percent O2 without duct firing and to 4.00 ppmvd at 15 percent O2 with and without duct firing, with the majority VOC BACT limits range from 1.00 to 2.00 ppmvd at 15 percent O2. The majority of the facilities have installed oxidation catalysts for VOC control.

It is important to note that the achievable VOC emission rate for combustion turbines is not simply based on the use of CO oxidation catalysts as a post combustion control system, but also on the overall design of the entire combustion turbine, the heat recovery steam generator, and the operating conditions of the CT. General Electric has stated that the expected VOC emission rate for NIPSCO proposed GE Model 7HA.02 CTs in simple cycle and combined cycle modes is 1.00 ppmvd and 2.0 ppmvd @ 15% O2, respectively, when operating outside of startup and shutdown (SU/SD) conditions.

Except for Chickahominy Power project in Virginia, Novi Power Project in Virginia, and Killingly Energy Center project in Connecticut with lower VOC limits, the most recent BACT determinations for VOCs in the RBLC are greater than or equal to 1.0 ppmvd correct to 15% excess oxygen.

The CT air pollution control systems including the dry low NOx combustion systems and oxidation catalyst systems are not functional during periods of SU/SD because the burners cannot operate in the full premix mode during startup and shutdown, and because the CT exhaust gas temperatures are too low for the CO oxidation catalyst systems to function as designed. As a result, VOC emissions may be elevated during periods of SU/SD. Because these systems are not functional during startup and shutdown, the only method to minimize VOC emissions during these periods is by the use of good combustion practices designed to expeditiously startup and shut down the CTs as quickly as possible to minimize VOC emissions.

Step 5: Select BACT

Based on a review of the emission limits achievable and recent BACT determinations for similar facilities, NIPSCO has proposed that the use of good combustion practices in combination with the use of CO oxidation catalysts represents BACT for the control of VOC emissions from the proposed CTs during normal operation. Further, NIPSCO has proposed the use of good combustion practices designed to expeditiously start up and shutdown the CTs as quickly as possible to minimize VOC emissions represents BACT during periods of startup and shutdown.

Based on this analysis, NIPSCO proposes the following BACT limits for control of VOC emissions from the combustion turbines:

(a) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 1.00 ppmvd @ 15% O_2 on 3-hour average basis, excluding during periods of startup and shutdown for the combustion turbines for both simple cycle and combined cycle operations.

(b) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 2.00 ppmvd @15% O_2 on 3-hour average basis, excluding during periods of startup and shutdown when the combined cycle turbines are operated with duct burners.

(c) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 9.60 lb/hr on a 3-hour average basis, excluding during periods of startup and shutdown, when operating in combined cycle mode without duct burner.

(d) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 15.40 lb/hr on a 3-hour average basis, excluding during periods of startup and shutdown, when operating in combined cycle mode with duct burner.

(e) VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 9.10 lb/hr on a 3-hour average basis, excluding during periods of startup and shutdown, when operating in simple cycle mode.

(f) Total VOC emissions from each combustion turbine, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, during any periods of startup and shutdown operation shall not exceed 25.60 tons per 12-month rolling.

(g) VOC emissions from the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall be controlled using an oxidation catalyst and conducting good combustion practices.

GHG BACT Analysis – Combined Cycle Combustion Turbines

The PSD definition of GHG includes six (6) constituents: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). USEPA regulations and guidance establish a process to equate each individual GHG to a common CO_2e metric by equating the ability of each individual GHG to trap heat in the atmosphere to the same ability of one unit mass of CO_2. Aggregating all GHGs on a CO_2e basis allows evaluation of all GHGs using a single metric.

The combustion of natural gas in the generating units results in emissions of CO_2, CH_4, and N_2O. Nearly one hundred percent (100%) of combustion-related GHG emissions are in the form of CO_2 on a mass basis, since each carbon atom combusted in the fuel stream results in nearly one molecule of CO_2 emissions. CH_4 and N_2O form as the result of incomplete combustion and are formed in much lower quantities. Even when scaling CH_4 and N_2O by their relative global warming potentials (GWPs), these constituents combined contribute approximately one percent (1%) of the total GHG emissions (on CO_2e basis) resulting from the combustion of natural gas. Therefore, BACT assessment for the combustion turbine generating units is focused on CO_2. And, using CO_2 as a surrogate for a CO_2e BACT analysis is consistent with federal regulations. The following section presents a GHG BACT evaluation for the proposed combustion turbine generating units.

The proposed combustion turbines are subject to CO2 emission limits under the standards of performance for stationary combustion turbines under 40 CFR 60, Subpart TTTTa. Each of the proposed new natural gas-fired combustion turbines, when operating in simple cycle mode, will be 'intermediate load' category subject to CO2 limit of 1,170 lb/MWh (gross). When operating in combined cycle mode, new natural gas-fired combustion turbines will be subject to CO2 limit of 800 lb/MWh (gross). Therefore, the applicable standard in 40 CFR 60, Subpart TTTTa, Table 2 are the baseline CO2 rates for the proposed combustion turbines. There is no BACT baseline for CH4 and N2O emissions from the combustion turbines.

Step 1: Identify All Potentially Available Control Technologies

Based on a review of available information, the control strategies that may be considered to be potentially available for reducing GHGs emissions associated with the proposed combustion turbines include:

(1) Carbon capture and sequestration ("CCS")
(2) Efficiency Combustion Turbine design
(3) Fuel selection
(4) Good combustion practices ("GCP")

Carbon Capture and Sequestration (CCS)

Carbon Capture and Sequestration (CCS) involves separation and capture of nearly pure CO_2 stream from the combustion turbine exhaust gases using physical or chemical adsorption step. Thereafter, captured CO_2 is compressed for transportation via pipeline. Finally pure CO_2 is injected underground for long-term geologic storage of the captured CO_2. At this point, implementation of CCS technology, specifically post-combustion CO_2 capture technology, is not commercially available as it has not yet been successfully implemented on a large-scale basis such as a natural gas-fired combustion turbine-based power plant.

According to the CCS task force report, CO_2 capture technology is being operated at a small scale at several coal-fired power plants and there are plans to implement this technology on a larger scale at several coal-fired power plants in the coming years. However, CCS technology, specifically post-combustion CO_2 capture technology, is not commercially available and has not yet been successfully implemented on a large-scale basis for natural gas-fired combustion turbines. The combustion of natural gas and large turbine airflows results in exhaust streams with dilute concentrations of CO_2, 3-4%, versus 13-15% for coal-fired systems. As outlined in US EPA's GHGs permitting guidance, a control technology would not be applicable if it can be shown there are significant differences that preclude the successful operation of the control device. For example, the temperature, pressure, pollutant concentration, or volume of the exhaust stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review. Given this significant difference in exhaust CO_2 concentration and volume, it is uncertain that the CO_2 capture technologies currently

being investigated for coal-fired power plants can also be applied to natural gas-fired combustion turbines. Therefore, the use of CCS technology is not technically feasible.

Efficient Combustion Turbine Design

In general, combustion turbines which operate at higher temperatures (i.e., larger turbines) have the highest efficiencies. Increasing the efficiency of the turbines directly decreases GHGs emissions as less fuel is combusted per unit output. Therefore, efficient combustion turbines design is a technically feasible option for the combined cycle combustion turbines at this source.

Fuel Selection

Fuels containing less carbon have lower potential CO_2 and CH_4 emissions. Choosing a less carbonaceous fuel will decrease CO_2 and CH_4 emissions from the generation process as fewer carbon atoms are available. Natural gas is already the best choice in terms of possible fuels for reducing GHG emissions and natural gas is also part of the defined project. Therefore, fuel selection is technically feasible.

Good Combustion Practices (GCP)

Good combustion and operating practices (GCPs) are a potential control option by improving the fuel efficiency of the combustion turbine units. GCPs also include proper maintenance and tune-up of the combustion turbine units as recommended by the manufacturer and/or vendor. Good combustion practices are essential for the operation and life-span of the proposed combustion turbines. Therefore, good combustion practices are technically feasible.

Step 2: Eliminate Technically Infeasible Options

Carbon Capture and Sequestration (CCS)

As previously discussed under Step 1 above, according to the Interagency CCS Task Force Report, CO_2 capture technology is yet to be applied to natural gas-fired combustion turbines for separation of CO_2 from exhaust. Therefore, the use of CO_2 capture, and by extension CCS technology, is not technically feasible.

Fuel Selection

Selecting a low-carbon fuel is a technically feasible method of controlling GHG emissions from a combustion turbine unit. NIPSCO is proposing to burn natural gas in the proposed combustion turbines. Natural gas has relatively low carbon content compared to other possible fuels. Other typical fuels for use in a combustion turbine unit include fuel oil and synthetic natural gas (SNG). The combustion of fuel oil creates nearly 40 percent more CO_2 per MMBtu than combustion of natural gas, as well as 3 times and 6 times as much CH_4 and N_2O, respectively.

Synthetic gas is relatively equivalent to natural gas in terms of GHG emissions; however, switching to other fuels such as synthetic gas is not feasible for operations at NIPSCO - R.M. Schahfer Generating Station due to non-availability in the area. Furthermore, natural gas is already the best choice in terms of possible fuels for reducing GHG emissions and natural gas is also part of the defined project.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

As discussed above, CCS and fuel selection are deemed technically infeasible for controlling GHG emissions from the combustion turbines. All other control technologies discussed above are technically feasible.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Proposed: NIPSCO - Schahfer Generating Station	073-49556-00008 (Pending)	N/A	Four (4) Combined Cycle Combustion Turbines (3,400 MMBtu/hr, each)	**Control Method:** Good combustion practices Energy Efficiency Design **Emission Limit 1:** 1,170.0 lb/MW-hr (gross) during simple cycle mode, each (=116.98 lb/MMBtu) 863,649 tons/12 months period **Emission Limit 2:** 800.0 lb/MW-hr (gross) during combined cycle mode, each (=116.98 lb/MMBtu) 1,751,087 tons/12 months period
Simple Cycle Turbines				
Sycamore Riverside Energy LLC	153-47292-00062 (3/31/2025)	IN-0384	Simple Cycle Turbine (240 MW) (GE 7FA.05 CT)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 15,420.0 BTU KWH **Emission Limit 2:** 1,899.0 lb/MW-hr Entire source CO2e emissions shall not exceed 1,115,606 tons/yr
Jack County Generating Station	PSDTX1640,, GHGPSDTX240 (12/27/2024)	TX-0986	Simple Cycle Turbine (Siemens V84.3) (180.2 MW)	**Control Method:** Energy efficiency design Use of low carbon fuels **Emission Limit 1:** 1,400 lb/MW-hr; or 120 lb CO2/MMBtu
LBWL – Erikson Station	74-18D (12/20/2022)	MI-0454	Simple Cycle Turbine EUCTGSC1 (667 MMBtu/hr)	**Control Method:** Good Combustion Practices Low carbon fuel Energy efficiency measures **Emission Limit 1:** 318,404.0 ton/12 months rolling
Nacero Penwell Facility	164137 PSDTX1594GHGP SD TX207 (11/17/2021)	TX-0933	Simple Cycle Combustion Turbine	**Control Method:** Good Combustion Practices Use of gaseous fuel **Emission Limit 1:** --
El Paso Electric Company - Newman Power Station	N284, PSDTX1090M1, GHGPSDTX199 (08/27/2021)	TX-0908	Simple Cycle Turbine (230 MW)	**Control Method:** Good Combustion Practices Use of gaseous fuel **Emission Limit :** --
NRG Cedar Bayou LLC - Unit 5	160538, PSDTX1528, GHGPSDTX204 (03/17/2021)	TX-0915	Simple Cycle Turbine (1,661 MMBtu/hr)	**Control Method:** Low sulfur natural gas fuel **Emission Limit 1:** --

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Alaska Gasoline Development - Gas Treatment Plant	AQ1524CPT01 (08/13/2020)	AK-0085	Six (6) Simple Cycle Turbines (386 MMBtu/hr)	**Control Method:** Good Combustion Practices Clean Burning Fuels **Emission Limit 1:** 117.10 lb/MMBtu
Rio Bravo Pipeline Facility	140792, PSDTX1498, GHGPSDTX158 (12/17/2018)	TX-0851	Twelve (12) General Electric Frame 7EA (967 MMBtu/hr)	**Control Method:** Good Combustion Practices Use of pipeline quality natural gas **Emission Limit 1:** --
Venture Global - Calcasieu Pass LNG Project	PSD-LA-805 (09/21/2018)	LA-0331	Aeroderivative Simple Cycle Combustion Turbine (263.00 MMBtu/hr)	**Control Method:** Good Combustion Practices Combust low carbon fuel gas Good operation and maintenance practices and insulation **Emission Limit 1:** 134,907.0 ton/yr
			Simple Cycle Combustion Turbines (SCCT1 to SCCT3) (927 MMBtu/hr)	**Control Method:** Good Combustion Practices Combust low carbon fuel gas Good operation and maintenance practices and insulation **Emission Limit 1:** 1,426,146.0 ton/yr
Driftwood LNG Facility	PSD-LA-824 (07/10/2018)	LA-0349	Simple Cycle Combustion Turbines (20) (540 MMBtu/hr)	**Control Method:** Use of low carbon fuel Energy efficiency measures Good Combustion Practices **Emission Limit 1:** --
Southwestern Public Service Company – Gaines Power Plant	135322, PSDTX1470 and GHGPSDT (04/28/2017)	TX-0819	Four (4) Simple Cycle Combustion Turbines (Siemens SGT65000F5) (227.5 MW)	**Control Method:** Good Combustion Practices Pipeline quality natural gas limited hours **Emission Limit 1:** 1,300.0 lb/MW-h
Cameron LNG Facility	PSD-LA-766(M3) (02/17/2017)	LA-0316	Nine (9) Simple Cycle Combustion Turbines (1069 MMBtu/hr)	**Control Method:** Good Combustion Practices Natural Gas Fuel Use high thermal efficiency turbines **Emission Limit 1:** --
Brazos Electric Cooperative Hill County Generating Facility	130051,PSDTX1450, GHGPSDTX131 (04/07/2016)	TX-0794	Four (4) Simple Cycle Turbine (171.0 MW)	**Control Method:** -- **Emission Limit 1:** 1,434.0 lb/MW-hr
Apex Texas Power, LLC Neches Station	122401, PSDTX1428, GHGPSDTX111 (03/24/2016)	TX-0788	Simple Cycle Turbine (232.0 MW)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 1,341.0 lb/MW-hr

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Magnolia LNG Facility	PSD-LA-792 (03/21/2016)	LA-0307	Eight (8) Gas Turbines (333.0 MMBtu/hr)	**Control Method:** Good Combustion Practices Natural Gas Fuel Use intake air chiller **Emission Limit 1:** --
Combined Cycle Turbines				
Duke Energy Cayuga Station	165-47430-00001 (02/14/2025)	IN-0382	Two (2) Combined Combustion Turbines (6A and 6B) (4254 MMBtu/hr)	**Control Method:** Good Combustion Practices Efficiency turbine design **Emission Limit 1:** 850.0 lb/MW-hr (gross) 12 months rolling average
Maple Creek Energy LLC	T153-45909-00056 (6/19/2023)	IN-0365	Siemens Combined Cycle Combustion Turbine (CTGA) (3800 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** 726.0 lb/MW-hr (gross) **Emission Limit 2:** 2,040,335.0 ton/ 12 month rolling period
			GE Model 7HA.03 Combined Cycle Combustion Turbine (CTGB) (4200 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** 826.0 lb/MW-hr (gross) **Emission Limit 2:** 2,292,966.0 ton/ 12 month rolling period
	Maple Creek Energy LLC proposed a GHG limit of 726.0 lb/MW-h for its Siemens model turbine and a GHG limit of 826.0 lb/MW-h for its GE model turbine. While NIPSCO proposed to construct similar GE model turbines and proposed a limit of 800 lb/MW-h, the proposed BACT limit proposed by NIPSCO is consistent with BACT determination for GE model turbine proposed by Male Creek Energy LLC.			
Entergy Texas, Inc. (Orange County Advanced Power Station)	166032 PSDTX1598 GHGPSDTX210 (03/13/2023)	TX-0939	Combined Cycle Turbines (1215 MW)	**Control Method:** Good Combustion Practices Clean fuel **Emission Limit 1:** --
Midland Cogeneration Venture Limited Partnership	10-23 (02/01/2023)	MI-0455	Combined Cycle Turbine EUCTGHRSG1 (4197.6 MMBtu/hr)	**Control Method:** Good Combustion Practices Low carbon fuel Energy efficiency measures **Emission Limit 1:** 2,375,313.0 ton/12 months period **Emission Limit 2:** 1,000.0 lb/MW-h (gross) 12 months period average
LBWL – Erikson Station	74-18D (12/20/2022)	MI-0454	Combined Cycle Turbines EUCTGHRSG1 and EUCTGHRSG2 (667 MMBtu/hr)	**Control Method:** Low carbon fuel Good Combustion Practices Energy efficiency measures **Emission Limit 1:** 430,349.0 ton/ 12 months period **Emission Limit 2:** 1,000.0 lb/MW-h (gross), 12 months period average

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (7/29/22)	IL-0133	Two (2) Combined Cycle Combustion Turbine (3,647 MMBtu/hr, each)	**Control Method:** Inherently lower polluting design Good combustion practices Operational energy efficiency **Emission Limit 1:** 850.0 lb/MW-hr (gross), 12 months period
Alaska Gasoline Development Corporation – Liquefaction Plant	AQ1539CPT01 (07/07/2022)	AK-0088	Four (4) Simple Cycle Turbines (384 MMBtu/hr, each)	**Control Method:** Good Combustion Practices Burning clean fuels **Emission Limit 1:** 117.10 lb/MMBtu, 3-hrs
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Combined Cycle Combustion Turbine EUCTGHRSG (North Plant) (3064 MMBtu/hr; 500 MW)	**Control Method:** Energy efficiency measures Use of low carbon fuels **Emission Limit 1:** 2,001,019.0 ton/yr, 12 months period **Emission Limit 2:** 806.0 lb/MW-h, 12 months period average
Marshall Energy Center, LLC - MEC North, LLC	168-17B (06/23/2022)	MI-0452	Combined Cycle Combustion Turbine EUCTGHRSG (South Plant) (3064 MMBtu/hr; 500 MW)	**Control Method:** Energy efficiency measures Use of low carbon fuels **Emission Limit 1:** 2,001,019.0 ton/yr, 12 months period **Emission Limit 2:** 806.0 lb/MW-h, 12 months period average
Magnolia Power LLC - Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Combined Cycle Combustion Turbine EQT001 (5081 MMBtu/hr; 730 MW)	**Control Method:** Use of gaseous fuel (pipeline quality natural gas) Thermally efficient turbines Good combustion practices **Emission Limit 1:** 875.0 lb/MW-h annual average
Mountain State Clean Energy, LLC - Maidsville	R14-0038 (1/05/2022)	WV-0033	Two (2) Combined Combustion Turbine & Duct Burner (CT-01/HRSG1 and CT-02/HRSG2) (1275 MW)	**Control Method:** Thermally efficient turbines Combustion air cooling Use of lower carbon fuels **Emission Limit 1:** 852.0 lb/MW-h (gross) 12 months rolling average **Emission Limit 2:** 2,563,571.0 ton/12 months rolling total **Standard Emission Limit:** 1,000.0 lb/MW-h (gross) 12 months rolling average
NRG Cedar bayou LLC - Unit 5	160538, PSDTX1528, GHGPSDTX204 (03/17/2021)	TX-0915	Combined Combustion Turbine	**Control Method:** Low sulfur natural gas fuel **Emission Limit 1:** --

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Lansing Board of Water and Light LBWL - Erickson Station	74-18A (01/07/2021)	MI-0447	Two (2) Combined Combustion Turbines EUCTGHRSG1 and EUCTGHRSG2 (667 MMBtu/hr, each)	**Control Method:** Low carbon fuel (pipeline quality natural gas) Good combustion practices Energy efficiency measures **Emission Limit 1:** 430,349.0 ton/12 months period **Emission Limit 2:** 1,000.0 lb/MW-h, 12 months period average
Alabama Power Company - Plant Barry	503-1001 (11/09/2020)	AL-0328	Two (2) Combine Combustion Turbines (744 MW)	**Control Method:** Efficiency design **Emission Limit 1:** 1,000.0 lb/MW-h **Emission Limit 2:** 2,445,022.0 ton/yr
Nemadji Trail Energy Center	18-MMC-168 (09/01/2020)	WI-0300	Natural Gas Combined CycleTurbine (P01) (4,671 MMBtu/hr)	**Control Method:** Efficiency turbine design Combust pipeline quality NG Oxidation catalyst **Emission Limit 1:** 850.0 lb/MW-h 12 months rolling average
FG LA Complex	PSD-LA-812 (01/06/2020)	LA-0364	Cogeneration Units (2222 MMBtu/hr)	**Control Method:** Use of natural gas as fuel Energy efficient design operational/maintenance practices **Emission Limit 1:** 1,096,666.0 ton/yr
Indeck Niles, LLC	75-16B (11/26/2019)	MI-0445	Combined Cycle Turbines (3,421 MMBtu/hr)	**Control Method:** Good combustion practices Inlet air conditioning Pipeline quality natural gas **Emission Limit 1:** 1,911,481.0 ton/12 months rolling period, each 802 lb/MW-hr
Thomas Township Energy, LLC	210-18 (8/21/2019)	MI-0442	Combined Cycle Turbine (625 MW; 4,200 MMBtu/hr)	**Control Method:** Energy efficiency measures **Emission Limit 1:** 2,739,722.0 ton/12 months rolling period
Chickahominy Power LLC	52610-1 (6/24/2019)	VA-0332	Three (3) Combined Cycle Combustion Turbines (4,066 MMBtu/hr)	**Control Method:** Energy efficiency combustion practices Low GHG fuels **Emission Limit 1:** 812.0 lb/MW-hr 12 months rolling period total **Emission Limit 2:** 6,452.0 BTU/KW-h Net HHV
Lansing Board of Water and Light LBWL - Erickson Station	74-18 (12/21/2018)	MI-0441	Two (2) Combined Cycle Combustion Turbines (667 MMBtu/hr, each)	**Control Method:** Low carbon fuel (pipeline quality natural gas) Good combustion practices Energy efficiency measures **Emission Limit 1:** 430,349.0 ton/12 months period

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Venture Global Calcasieu Pass LNG Project	PDS-LA-805 (09/21/2018)	LA-0331	Five (5) Combined Cycle Combustion Turbines (CCCT1 to CCCT5) (921 MMBtu/hr)	**Control Method:** Combust low carbon fuel gas Good combustion practices **Emission Limit 1:** 2,602,275.0 ton/yr annual total (5 turbines)
Brooke County Power Plant	R14-0035 (9/18/2018)	WV-0032	Combined-cycle Turbine (2,737.7 MMBtu/hr; 462.5 MW)	**Control Method:** Use of natural gas Turbine Model GE7HA **Emission Limit 1:** 417,382.0 lb/hr **Standard Emission Limit:** 829.0 lb/MW-hr
New Covert Generating Facility	186-17 (07/30/2018)	MI-0432	Three (3) Combined Cycle Combustion Turbines (1230 MW)	**Control Method:** Energy efficiency measures Use of natural gas **Emission Limit 1:** 1,425,081.0 t/12 months rolling period, each **Emission Limit 2:** 7,978.0 BTU/ KW-h 12 months rolling period, each
Marshall Energy Central LLC - MEC North, LLC and MEC South, LLC	167-17 AND 168-17 (06/29/2018)	MI-0433	Two (2) Combined Cycle Combustion Turbines (South Plant and North Plant) (500 MW)	**Control Method:** Energy efficiency measures Use of low carbon fuel (pipeline quality natural gas) **Emission Limit 1:** 1,978,297.0 ton/12 months rolling period, each unit **Emission Limit 2:** 806.0 ton/12 months rolling period, each unit
Novi Energy C4GT, LLC	52588 (04/26/2018)	VA-0328	GE Combustion Turbine with HRSG (3,482 MMBtu/hr)	**Control Method:** Energy efficiency combustion practices Low GHG fuels **Emission Limit 1:** 883.0 lb/MW-h 12 months rolling total **Emission Limit 2:** 6,745.0 BTU/KW-h NET HHV
			Siemens Combustion Turbine with HRSG (3,116 MMBtu/hr)	**Control Method:** Energy efficiency combustion practices Low GHG fuels **Emission Limit 1:** 883.0 lb/MW-h 12 months rolling total **Emission Limit 2:** 6,625.0 BTU/KW-h NET HHV
Harrison Power	P0122266 (4/19/2018)	OH-0377	GE Combustion Turbines (P005 and P006) (3459.6 MMBtu/hr)	**Control Method:** High efficiency combustion technology **Emission Limit 1:** 1,000.0 lb/MW-h with DB **Emission Limit 2:** 1,012.40 lb/MW-h without DB

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
			Mitsubishi/Hitachi Combustion Turbines (P007 and P008) (3231 MMBtu/hr)	**Control Method:** High efficiency combustion technology **Emission Limit 1:** 1,000.0 lb/MW-h with DB **Emission Limit 2:** 976.0 lb/MW-h without DB
Entergy Texas Inc - Montgomery County Power Station	N256, PSDTX1510, and GHGPSDTX1 (03/30/2018)	TX-0834	Combined Cycle Turbine (2,635 MMBtu/hr)	**Control Method:** Pipeline quality natural gas Good combustion practices **Emission Lim it 1:** 884.0 lb/MW-h
ESC Harrison County Power Plant	R14-0036 (03/27/2018)	WV-0029	Combined Cycle Turbine (3,496.2 MMBtu/hr; 640 MW)	**Control Method:** Use of natural gas Turbine Model GE7HA **Emission Limit 1:** 528,543.0 lb/hr **Emission Limit 2:** 2,315,020.0 ton/yr **Standard Emission Limit:** 826.0 lb/MW-hr
Robinson Power Company LLC - Beech Hollow	63-00922D (12/27/2017)	PA-0314	Combustion Turbine (2433 MMBtu/hr)	**Control Method:** -- **Emission Limit 1:** 2,930,740.0 ton/yr with DB **Emission Limit 2:** 404,917.0 lb/hr without DB 1,465,370.0 ton/yr without DB
Florida Power and Light Company Dania Beach Energy Center	0110037-017-AC (12/04/2017)	FL-0363	Combined Cycle Turbine Unit (GE 7HA) (4000 MMBtu/hr)	**Control Method:** Low emitting fuels **Emission Limit 1:** 850.00 lb/MW-h 12 months period
Guernsey Power Station LLC	P0122594 (10/23/2017)	OH-0374	Three (3) Combined Cycle Combustion Turbines (P001 - P002) (3,516 MMBtu/hr; 1,650 MW)	**Control Method:** High efficiency combustion practices as recommended by the manufacturer **Emission Limit 1:** 846.0 lb/MW-h (gross) without DB **Emission Limit 2:** 1,000.0 lb/MW-h (gross) with DB 7,056,798 ton/12 months for all three turbines
Oregon Energy Center	P0121049 (09/27/2017)	OH-0372	Combined Cycle Combustion Turbines (P001 and P002) (3,055 MMBtu/hr)	**Control Method:** High efficiency combustion design **Emission Limit 1:** 833.0 lb/MW-h (gross) without DB **Emission Limit 2:** 401,921.0 lb/hr with DB 1,689,461 ton/12 months period, including SU/SD

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Trumbull Energy Center	P0122331 (09/07/2017)	OH-0370	Combined Cycle Turbine (P001 and P002) (3025 MMBtu/hr; 940 MW)	**Control Method:** High efficiency combustion design **Emission Limit 1:** 833.0 lb/MW-h (gross) without DB **Emission Limit 2:** 401,921.0 lb/hr with DB 1,683,213 ton/12 months period, including SU/SD
NTE Connecticut, LLC Killingly Energy Center	089-0107 (06/30/2017)	CT-0161	Combustion Turbine without DB (2969 MMBtu/hr)	**Control Method:** Use of low carbon fuel **Emission Limit 1:** 7,273.0 BTU/KW-hr 12 months rolling **Emission Limit 2:** 816.0 lb/MW-hr
Southwestern Public Service Company Gaines County Power Plant	135322, PSDTX1470, AND GHGPSDT (04/28/2017)	TX-0819	Combined Cycle Turbine with HRSG (426 MW)	**Control Method:** Pipeline quality natural gas **Emission Limit 1:** 960.0 lb/MW-h
Hilltop Energy Center, LLC	30-00233B (04/12/2017)	PA-0315	Combustion Cycle Turbine without duct burner (4,367 MMBtu/hr)	**Control Method:** -- **Emission Limit 1:** 879.0 lb/MW-h (gross) **Emission Limit 2:** 298,774.0 ton/yr
INEOS USA LLC - Chocolate Bayou Steam Generating (CBSG) Station	123117, PSDTX1460, GHGPSDTX135 (02/17/2017)	TX-0817	Combustion Cycle Cogeneration (50 MW)	**Control Method:** -- **Emission Limit 1:** 1000.0 lb/MW-h
Indeck Niles, LLC	75-16 (01/04/2017)	MI-0423	Two (2) Combustion Cycle Turbine (3421 MMBtu/hr, each)	**Control Method:** Energy efficiency measures Use of low carbon fuel **Emission Limit 1:** 2,097,001.0 ton/ 12 months rolling period **Emission Limit 2:** 802 lb/MW-h
Holland Board of Public Works - East 5th Street	107-13C (12/05/2016)	MI-0424	Two (2) Combustion Cycle Turbine (554 MMBtu/hr, each)	**Control Method:** Energy efficiency measures Use of low carbon fuel **Emission Limit 1:** 312,321.0.0 ton/ 12 months rolling period **Emission Limit 2:** 992.0 lb/MW-h
South Field Energy, LLC	P0119495 (09/23/2016)	OH-0367	Two (2) Combined Cycle Combustion Turbines (3,131 MMBtu/hr)	**Control Method:** Energy efficiency measures **Emission Limit 1:** 481,301.0 lb/hr with DB **Emission Limit 2:** 2,045,634.0 ton/ 12 months rolling period
CPV Fairview Energy Center	11-00536A (09/02/2016)	PA-0310	Combustion Turbine and HRSG with DB (3338 MMBtu/hr)	**Control Method:** Low sulfur fuel Good combustion practices **Emission Limit 1:**

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
				3,352,086.0 ton/ 12 months rolling period
Energy Louisiana, LLC - St. Charles Power Station	PSD-LA-804 (08/31/2016)	LA-0313	Two (2) Combined Cycle Combustion Turbines (3625 MMBtu/hr; 980 MW)	**Control Method:** Thermally efficient combustion turbines Good combustion practices **Emission Limit 1:** 1,000.0 lb/MW-h
Stonegate Power, LLC - Middlesex Energy Center, LLC	19149/PCP150001 (07/19/2016)	NJ-0085	Combined Cycle Combustion Turbine with Duct Burner (633 MW)	**Control Method:** Use of natural gas clean burning fuel **Emission Limit 1:** 888.0 lb/MW-h (gross) based on 12 months rolling period
Virginia Electric and Power Company - Greensville Power Station	52525 (06/17/2016)	VA-0325	Three (3) Combined Cycle Combustion Turbines with Duct Burner (3227 MMBtu/hr; 1,600 MW)	**Control Method:** -- **Emission Limit 1:** 890.0 lb/MW-h **Emission Limit 2:** 1,911,596.0 ton/yr
Apex Texas Power LLC - Neches Station	122401, PSDTX1428, GHGPSDTX111 (03/24/2016)	TX-0788	Two (2) Combustion Turbines (231 MW)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 924.0 lb/MW-h
PSEG Fossil LLC Sewaren Generating Station	18068/BOP150001 (03/10/2016)	NJ-0084	One (1) Simple Cycle Combustion Turbine without Duct burner (3219 MMBtu/hr)	**Control Method:** -- **Emission Limit 1:** 888.0 lb/MW-h (gross) on 12 months rolling period
Florida Power & Light Okeechobee Clean Energy Center	0930117-001-AC (03/09/2016)	FL-0356	Three (3) Combined Cycle Combustion Turbine (3096 MMBtu/hr; 1,600 MW)	**Control Method:** Use of low emitting fuels and technologies **Emission Limit 1:** 850.0 lb/MW-h on 12 months rolling period
Tenaska PA Partners, LLC - Westmoreland Generating Station	65-00990 C/E (02/12/2016)	PA-0306	Two (2) Combined Cycle Combustion Turbines (930 MW)	**Control Method:** Good combustion practices **Emission Limit 1:** 1,881,905.0 ton/yr
Lackawanna Energy Center, LLC - CTR/Jessup	35-00069A (12/23/2015)	PA-0309	Three (3) Combustion Turbines with duct burner (1,500 MW)	**Control Method:** -- **Emission Limit 1:** 1,629,115.0 ton/yr
CPV Towantic, LLC	144-0024 (11/30/2015)	CT-0158	Combined Cycle Combustion Turbine (805 MW)	**Control Method:** -- **Emission Limit 1:** 809.0 lb/MW-h without DB **Emission Limit 2:** 7720.0 BTU/KW-h on 12 months rolling period
Mattawoman Energy LLC Center	PSC CASE. NO. 9330 (1/13/2015)	MD-0045	Two (2) Combined Cycle Combustion Turbine (286 MW, each)	**Control Method:** -- **Emission Limit 1:** 865.0 lb/MW-h on 12 months rolling period

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
FGE Eagle Pines, LLC - Project	131316, PSDTX1454, And GHGPSDT (11/04/2015)	TX-0773	Three (3) Combined Cycle Turbines (321 MW)	**Control Method:** Low carbon fuel good combustion efficiency combined cycle design **Emission Limit 1:** 886.0 lb/MW-h without DB **Emission Limit 1:** 816.0 lb/MW-h with DB

The most stringent RBLC and permit entries for GHG control are provided. GHG BACT determinations are expressed in varying units, including mass emission rates (tons or pounds per unit time), pounds of CO2e emitted per megawatt-hour of energy produced (lb CO2e per MW-hr), and/or “heat rate” (British thermal units per kilowatt-hour [Btu/kW-hr]). The energy-based limits are expressed as either “gross” or “net,” with gross reflecting the output from the CTGs and net reflecting the output to the transmission grid. Energy units (MW-hr or kilowatt-hour) are more meaningful than mass emission limits since they relate directly to the efficiency of the equipment, which is the primary GHG BACT technology currently available (in addition to low-carbon fuel). The mass emissions are specific to the fuel firing rate of a given facility and the carbon content of the fuel, but do not incorporate facility efficiency.

The lowest limit provided in the table when operating in simple cycle mode is 1,300 lb/MW-hr, 12-month rolling average. There are other new and clean permit limits listed in the table between 1,300 and 1,899 lb/MW-hr that are limited to full operating load for various CTG technologies. The limits for GHG BACT determinations when operating in simple cycle mode are also expressed in units of mass emission rates and heat rates; however, limits in terms of energy units are more meaningful as they relate directly to the efficiency of the equipment.

The lowest limits provided in the table when operating in combined cycle mode are 726 lb/MW-hr, which was determined for a Siemens models turbine. There are other new and clean permit limits listed in the table between 726 and 1,012.4 lb/MW-hr that are limited to full operating load for various CTG technologies. The most recent BACT determination has a GHG limit greater 800 lb/MW-hr gross, 12-month rolling average. The majority of the BACT limits when operating in combined cycle mode are ranged from 850 lb/MW-h to 1,000 lb/MW-h, which take into account all modes of operation. The limits for GHG BACT determinations operating in combined cycle mode are also expressed in units of mass emission rates and heat rates; however, limits in terms of energy units are more meaningful as they relate directly to the efficiency of the equipment.

NIPSC - R.M. Schahfer Generating Station is proposing a GHG BACT limit of 1,170.0 lb/MW-hr (gross) when operating in simple cycle mode and a GHG BACT limit of 800.0 lb/MW-h when operating in combined cycle mode. Additionally, NIPSCO proposed the use of good combustion practices and energy efficient design as BACT for the control of GHGs emissions from the proposed CTs during normal operation.

Step 5: Select BACT

Based on a review of the emission limits achievable and recent BACT determinations for similar facilities, the proposed GHG BACT limits by NISCO - R.M. Schahfer Generating Station are lower than or within the range of the other GHG BACT limits in the RBLC.

NIPSCO - R.M. Schahfer Generating Station proposes to meet these limits through the use of good combustion practices and energy efficient design. Further, NIPSCO - R.M. Schahfer Generating Station has concluded that the use of good combustion practices designed to

expeditiously startup and shutdown the combustion turbines as quickly as possible to minimize GHGs emissions represents BACT during periods of startup and shutdown.

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for GHG for the combustion turbines shall be as follows:

(a) CO_2 emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 1,170 lb/MW-hr (gross) per twelve (12) operating month period average when operating in simple cycle mode.

(b) CO_2 emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall not exceed 800 lb/MW-hr (gross) per twelve (12) operating month period average when operating in combined cycle mode.

(c) CO_2e emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, shall be limited through the use of good combustion practices and energy efficient design.

(d) The total GHGs (CO2, CH4, and N2O) emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, when operating in simple cycle mode, including steady state operation and operation during any periods of startup and shutdown, shall not exceed 863,649 tons per twelve (12) consecutive month period with compliance determined at the end of each month (GWPs per 78 FR 71948).

(e) The total GHGs (CO2, CH4, and N2O) emissions from each of the combustion turbines, identified as Unit 21A, Unit 21B, Unit 22A, and Unit 22B, when operating in combined cycle mode, including steady state operation and operation during any periods of startup and shutdown, shall not exceed 1,751,087 tons per twelve (12) consecutive month period with compliance determined at the end of each month (GWPs per 78 FR 71948).

BACT Analysis – Auxiliary Boiler

Emission Unit Description

Two (2) natural gas-fired auxiliary boilers, identified as AUX1 and AUX2, approved in 2026 for construction, each with a maximum rated capacity of 115 MMBtu per hour, using low NOx burners, and exhausting to stacks SAUX1 and SAUX2..

[Under 40 CFR 60, Subpart Db, these units are affected facilities]
[Under 40 CFR 63, Subpart DDDDD, these units are affected sources]

VOC BACT Analysis – Auxiliary Boiler

VOC are emitted from natural gas-fired auxiliary boilers because of incomplete combustion of gaseous fuel.

Step 1: Identify Potential Control Technologies

Emissions of Volatile Organic Compounds (VOCs) are generally controlled by oxidation. Oxidation technologies include regenerative thermal oxidation, catalytic oxidation, and flares.

(1) Regenerative thermal oxidation;
(2) Recuperative thermal oxidizer
(3) Catalytic oxidation;
(4) Good Combustion Controls; and

(5) Flares.

If add-on control technology is not feasible, an alternate method of control may be implemented.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers

The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors. Upon passing through the flame, the waste gas containing VOCs is heated. The mixture continues to react as it flows through the combustion chamber.

The required level of VOCs destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000°F. Once the unit is designed and built, the residence time is not easily changed, so that the required reaction temperature becomes a function of the particular gaseous species and the desired level of control.

A Regenerative Thermal Oxidizer incorporates heat recovery and greater thermal efficiency through the use of direct contact heat exchangers constructed of a ceramic material that can tolerate the high temperatures needed to achieve ignition of the waste stream.

The inlet gas first passes through a hot ceramic bed thereby heating the stream (and cooling the bed) to its ignition temperature. The hot gases then react (releasing energy) in the combustion chamber and while passing through another ceramic bed, thereby heating it. The process flows are then switched, feeding the inlet stream to the hot bed. This cyclic process affords very high energy recovery (up to 95%). The higher capital costs associated with these high-performance heat exchangers and combustion chambers may be offset by the increased auxiliary fuel savings to make such a system economical.

Based on this information, the use of a regenerative thermal oxidizer is not a technically feasible option for the auxiliary boilers at this source.

Recuperative Thermal Oxidizers

This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1.200°F and the waste stream inlet pollutants concentration is as low as 500-50,000 scfm.

Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases. Thermal oxidizers do not reduce emissions of VOC from properly operated natural gas combustion units without the use of a catalyst.

Based on this information, the use of a recuperative thermal oxidizer is not a technically feasible option for the auxiliary boilers at this source.

Catalytic Oxidizers

Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers operate at 600°F to 800°F and approximately require 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate.

Like thermal oxidation, waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures. Typical waste stream inlet flow rate ranges from 700 - 50,000 scfm and waste stream inlet pollutant concentration is as low as 1ppmv.

Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.

Catalytic oxidizer control is not implemented for small boilers such the one proposed by NIPSCO - R.M. Schafer Generating Station. In addition, these technologies may not provide consistent CO and VOC control efficiencies and may be difficult to operate when used to reduce CO and VOC emissions from sources that operate for short periods of time and that experience frequent starts/stops

Based on this information, the use of a catalytic oxidizer is not a technically feasible option for the small auxiliary boilers at this source.

Flare

Although the VOC concentration is very low, the stream flow rate is very high. The low heating value of the stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NOx. Flares have not been utilized or demonstrated as a control device for VOCs from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on this information, the use of a flare is not a technically feasible option for the auxiliary boilers at this source.

Good Combustion Controls

Good combustion controls is a continued operation of the boilers at the appropriate oxygen range and temperature to promote complete combustion and minimize VOC formation. Because VOC is essentially a by-product of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of VOC emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. VOC emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting VOC emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of good combustion practices is a technically feasible option for the auxiliary boilers at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The remaining technically feasible controls are:

(1) good combustion practices.

Step 4: Evaluate Top Control Alternatives

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Proposed: NIPSCO - Schahfer Generating Station	073-49556-00008 (Pending)	N/A	Auxiliary Boilers (115 MMBtu/hr, each)	**Control Method:** Good combustion practices Use of natural gas fuel **Emission Limit:** 5.5 lb/MMcf (0.005 lb/MMBtu), each
Duke Energy Indiana, LLC - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	Auxiliary Boiler (225 MMBtu/hr)	**Control Method:** Good combustion practices **VOC Emission Limit:** 0.005 lbs/MMBtu
Midwest Fertilizer Company LLC	129-44510-00059 05/06/2022	IN-0324	Auxiliary Boilers (218.60 MMBtu/hr)	**Control Method:** Combust natural gas **Emission Limit 1:** 5.5 lb/MMcf 3-hr average **Emission Limit 2:** 1877.39 MMcf/ 12 month rolling period
Nemadji Trail Energy Center	18-MMC-168 (09/01/2020)	WI-0300	Auxiliary Boiler (100 MMBtu/hr)	**Control Method:** Oxidation Catalyst and operate and maintain boiler according to manufacturer's recommendations **Emission Limit 1:** 0.0027 lb/MMBtu
	While the proposed auxiliary boiler at Nemadji Trail Energy Center has been determined to meet a VOC limit of 0.0027 lb/MMBtu with the use of an oxidation catalyst, this source has not been constructed. This permit has been revoked and this source has not been constructed. Therefore, this limit has not been demonstrated in practice.			
Chickahominy Power, LLC	52610-1 (06/24/2019)	VA-0332	Auxiliary Boiler (721 MMcf/yr)	**Control Method:** Good combustion practices Operator training Proper unit design **Emission Limit 1:** 0.005 lb/MMBtu **Emission Limit 2:** 1.90 ton/ 12 month rolling average
ESC Brooke County Power I, LLC Brooke County Power Plant	R14-0035 (9/18/2018)	WV-0032	Auxiliary Boiler (111.9 MMBtu/hr)	**Control Method:** Use of natural gas Good combustion practices **Emission Limit 1:** 0.90 lb/hr **Emission Limit 2:** 2.05 ton/yr

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
				Emission Limit 3: 0.008 lb/MMBtu
Duke Energy Indiana, LLC - Edwardsport Generating Station	083-38023-00003 (07/10/2018)	IN-0287	Auxiliary Boiler (213.0 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** 0.005 lb/MMBtu, Startup and shutdown emissions only
Novi Energy C4GT, LLC	52588 (04/26/2018)	VA-0328	Auxiliary Boiler (902 MMcf/yr)	**Control Method:** Good combustion practices **Emission Limit 1:** 0.005 lb/MMBtu **Emission Limit 2:** 2.30 ton/ 12 month rolling average
IGP Methanol, LLC - Gulf Coast Methanol Complex	PSD-LA-820 (01/04/2018)	LA-0346	Auxiliary Boiler (773.0 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** --
Guernsey Power Station, LLC	P0122594 (10/23/2017)	OH-0374	Auxiliary Boiler (182.0 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** 0.930 lb/hr **Emission Limit 2:** 2.330 ton/yr per 12 month rolling period **Standard Emission Limit:** 0.005 lb/MMBtu
Midwest Fertilizer Company	129-36943-00059 (03/23/2017)	IN-0263	Auxiliary Boiler (218.60 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** 5.50 lb/MMcf, 3-hr average **Emission Limit 2:** 1,877.39 MMcf/ 12 month rolling average
Virginia Electric and Power Company - Greensville Power Station	52525 (06/17/2016)	VA-0325	Auxiliary Boiler (185.0 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** 0.50 ton/ 12 month rolling total
Magnolia LNG Facility	PSD-LA-792 (03/21/2016)	LA-0307	Auxiliary Boiler (171.0 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** --
Tenaska Partners - Westmoreland Generating Facility	65-00990 C/E 02/12/2016	PA-0306	Auxiliary Boiler (245.0 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** 0.0054 lb/MMBtu **Emission Limit 2:** 2.89 ton/yr

Based on the RBLC search results, the majority of VOC BACT limits range from 0.005 lb/MMBtu to 0.008 lb/MMBtu. The only remaining technology is good design and operating practices. A properly designed and operated boiler minimizes VOC formation by ensuring that the boiler temperature and oxygen availability are adequate for complete combustion. Good design and operating practices is considered BACT for VOC emissions for the proposed boiler. The BACT limits proposed NIPSCO for the auxiliary boilers are consistent with the other proposed BACT limits determined in the RBLC.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the auxiliary boilers shall be as follows:

(a) VOC emissions from each auxiliary boiler, identified as AUX1 and AUX2, shall not exceed 5.5 lb/MMcf, each.

(b) VOC emissions from the auxiliary boilers, identified as AUX1 and AUX2, shall be controlled through the use of good combustion practices.

GHGs BACT Analysis – Auxiliary Boiler

Step 1: Identify Potential Control Technologies

Based on a review of available information, the control strategies that may be considered to be potentially available for reducing GHGs emissions associated with the proposed auxiliary boilers include:

(1) Carbon Capture and Sequestration (CCS)
(2) Selection of Efficient Auxiliary Boiler
(3) Low Carbon Fuel Selection
(4) Good Combustion Practices
(5) Alternative Fuels- Biomass/Cofiring
(6) Fuel Switching
(7) Operating and Maintenance Practices
(8) Improved Combustion Measures: Combustion Tuning
(9) Improved Combustion Measures: Optimization & Digital Control System
(10) Air Preheat & Economizers
(11) Turbulators for Firetube Boilers
(12) Boiler Insulation
(13) Minimization of Air Infiltration
(14) Boiler Blowdown Heat Exchange
(15) Condensation Return System
(16) Minimization of Gas-side heat Transfer Surface Deposits
(17) Steam Line Maintenance

Step 2: Eliminate Technically Infeasible Options

Carbon Capture and Sequestration (CCS)

Carbone capture and sequestration (CCS) is not feasible solely for small combustion units such as the 115 MMBtu per hour natural gas-fired auxiliary boilers proposed with this project. However, since the proposed project also includes large combustion sources (i.e., CCCTs), it is potentially feasible to capture and transfer CO_2 emissions from these units. As discussed above, CCS is eliminated as a control technology for the combustion turbines units. Therefore, this option is not evaluated in the subsequent analysis. In addition, the RBLC data and prior permits do not include CCS as control option for any of the listed auxiliary boilers sources.

Selection of Efficient Auxiliary Boiler

New efficient burner designs for all types of boilers and fuels are commercially available to help minimize fuel combustion and GHG emissions. Burners with single and multiple fuel capability, low and ultra-low NOx models, and sizes ranging from very small to very large are widely

deployed in industry. Further, the burner size and turndown capability (i.e., ability to operate and/or efficiency of operation at less than full load) are also key aspects of burner design as they will impact the losses associated with inefficient low load and on/off cycling duty. A higher turndown ratio reduces burner startups, provides better load control, saves wear-and-tear on the burner, and reduces purge-air requirements, all resulting in better overall efficiency. Therefore, site-specific conditions and objectives may favor one model over the other. The emission reduction is up to a 6% reduction of CO_2 emissions.

Efficient boiler design is technically feasible, taking into account the size, fuel flexibility, operating loads, and other site-specific conditions and objectives.

Low Carbon Fuel Selection

Selecting a low-carbon fuel is a technically feasible method of controlling GHG emissions from a combustion unit. NIPSCO is proposing to burn natural gas in the auxiliary boilers. Natural gas has a relatively low carbon content compared to other possible fuels, such as fuel oil and synthetic natural gas (SNG). The combustion of fuel oil creates nearly 40 percent more CO_2 than combustion of natural gas, as well as 3 times and 6 times as much CH_4 and N_2O, respectively. SNG is relatively equivalent to natural gas in terms of GHG emissions; however, natural gas is much more readily available near the proposed project site making natural gas a more logistically feasible option. Use of low-carbon fuel such as natural gas is technically feasible for this operation.

Good Combustion Practices

Good combustion practices (GCPs) are a potential control option by improving the fuel combustion efficiency of the auxiliary boilers. GCPs also include proper maintenance and tune-up of the boilers as recommended by the manufacturer/vendor. Therefore, this option is also technically feasible.

Alternative Fuels-Biomass/Co-firing

The potential on-site reduction in CO_2 emissions that may be realized by switching from a traditional fossil fuel to a biomass fuel is based on the specific emission factor for the fuel as related to its caloric value. Pure biomass fuels include animal meal, waste wood products and sawdust, and sewage sludge. It may also be possible to use biomass materials that are specifically cultivated for fuel use, such as wood, grasses, green algae, and other quick growing species.

Gas co-firing involves modification of the combustion system to accommodate the introduction of natural gas or biomass-derived gas. The co-fired fuel is injected directly into the combustion zone. Co-firing of natural gas or biofuels does not present any technical issues which cannot be addressed through appropriate design. In most cases, the issues associated with these fuels relate to economic attractiveness, availability of biofuels, and availability of natural gas at the plant site.

Availability of gaseous biomass-based fuels is limited such that a consistent supply of fuel cannot be assured over the life of the boiler. In addition, the combustion of biomass-based fuels can affect compliance with BACT limits for other pollutants, such as NOx and CO. The boiler will be initially constructed and operated to utilize only natural gas. Should a consistent, reliable source of gaseous biomass-based fuels become available, use of these fuels will be evaluated on an individual basis. Therefore, the use of co-firing with a biomass-based fuel is technically infeasible.

Fuel Switching

Fuel switching refers to a change in the plant hardware to accommodate complete replacement of one fuel with another fuel. Coal could be switched to oil, natural gas, or coal-derived gas; and oil could be switched to natural gas or coal-derived gas to achieve emissions reductions. This does not apply to natural gas combustion units; therefore, it is technically infeasible.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of fuel switching is not technically feasible option for the auxiliary boilers AUX1 and AUX2 at this source.

Operating and Maintenance Practices

Boiler efficiency decreases over time; however, the rate of deterioration can be curbed by proper Operating and Maintenance (O&M) practices. A well operated and maintained plant will experience less deterioration of boiler efficiency.

Deterioration results in higher heat rate, CO_2 emissions, and operating costs; in lower reliability; and in some cases, reduced output. After a few years of neglect, it may reach the point where significant investment is required to rehabilitate the plant and bring it as close as possible to the design performance.

Operation and maintenance according to the manufacturer's emission-related instructions (in a manner consistent with safety and good air pollution control practices for minimizing emissions) will prevent generation of additional GHG emissions due to efficiency losses over the lifetime of each piece of combustion equipment. Therefore, operation and maintenance practices is a technically feasible option for the auxiliary boilers AUX1 and AUX2 at this source.

Improved Combustion Measures: Combustion Tuning

Tuning of the combustion system requires a visual check by an experienced boiler engineer to ensure that everything is in good working condition and set according to the manufacturer’s recommendations or the optimum settings developed for the particular boiler. Simple parametric testing may be required, which may involve changes in the key control variables of the combustion system and observation of key parameters such as CO emissions, steam outlet conditions, flue gas outlet (stack) temperature, and NOx emissions. Up to a 3% reduction in CO_2 emissions.

As part of the O&M practices, combustion tuning of boilers will be conducted on an as-needed basis to address any decreases in boiler efficiency over time.

Based on this information, the use of Improved Combustion Measures: Combustion Tuning is a technically feasible option for the auxiliary boilers at this source.

Improved Combustion Measures: Optimization & Digital Control System

Optimization can be accomplished through parametric testing, analysis of the results, parameter estimation, periodic testing, and/or manual tuning. Software-based optimization systems may be cost effective for large boilers.

Digital control systems are generally necessary to achieve the greatest improvement in performance through tuning and optimization. Temperature sensors, oxygen monitors, oxygen trim controls, and other instrumentation may be required to maximize boiler efficiency.

The addition of optimization systems, modern control systems, and instrumentation has resulted in efficiency improvements of 0.5 to 5%.

The selected boiler will be equipped with oxygen trim control and oxygen analyzers. Therefore, this option is technically feasible for the auxiliary boilers at this source.

Air Preheat & Economizers

Energy efficiency can be increased by using waste heat gas recovery systems to capture and utilize heat in the flue gas. The most commonly used waste heat recovery methods are preheating combustion air and water heating via economizer. Economizers and air preheaters often occupy a substantial physical footprint.

There are two general types of air preheaters: recuperators and regenerators. Recuperators are gas-to-gas heat exchangers usually placed on the boiler stack. Internal tubes or plates transfer heat from the outgoing exhaust to the incoming combustion air. Regenerators include two or more separate heat storage sections. The hot flue gas heats the heating plates which in turn heat the incoming combustion air. General benefits include improved efficiency and faster startup. Efficiency typically increases by 1% for each 40°F reduction in flue gas temperature.

In an economizer, tubular heat transfer surfaces preheat the boiler feedwater before it enters the steam drum or furnace surfaces. Economizers also reduce the potential of thermal shock and strong water temperature fluctuations as the feedwater enters the drum or waterwalls. Economizers are typically installed on larger units. Air preheaters typically increase efficiency by 1% for each 40°F reduction in flue gas temperature. Economizers typically operate at a thermal efficiency of 5%.

Air preheaters are not widely used for industrial, commercial, or institutional boilers as the resulting increases in combustion temperature contribute to elevated emissions of NOx. The auxiliary boiler will be equipped with an economizer.

Based on this information, the use of this control option is technically feasible for the auxiliary boilers at this source.

Turbulators for Firetube Boilers

Turbulators create turbulence within the firetubes to improve heat transfer characteristics. An array of baffles, blades, or coiled wires disturbs the laminar boundary layer within the firetubes, resulting in increased convective heat transfer. Turbulators are often considered a more economical alternative to economizers or air preheaters. Turbulators are typically installed on older firetube boilers operating with fewer tube passes than newer boilers given that multi-pass boilers utilize a greater heat transfer area and are inherently more efficient. Efficiency typically increases by 1% for each 40°F reduction in flue gas temperature. Turbulators are substitutes for more costly economizers or air preheaters. As the selected boiler will already come equipped with an economizer, the turbulator was not considered to be necessary.

Based on this information, the use of turbulators for firetube boiler is a technically feasible option for the auxiliary boilers at this source.

Boiler Insulation

Significant heat losses can occur through the boiler shell. Proper insulation is used to minimize such losses. The refractory material handling inside the boiler is the primary insulating material, but properly applied insulation on the outer boiler surface can also reduce heat loss.

Insulation is categorized as either mass or reflective type depending on whether it is intended to reduce conductive or radiative heat transmission, respectively. Radiation losses tend to increase with decreasing load and can be as high as 7% for small units or for larger units operating at

reduced loads. The Thermal Insulation Manufacturers' Association provides guidance for determining the optimum insulation thickness for various applications. Up to 7%, varying by boiler load. Energy efficient refractory will be installed.

Based on this information, the use of boiler insulation is a technically feasible option for the auxiliary boilers at this source.

Minimization of Air Infiltration

Air infiltration occurs as a result of the large temperature difference between the hot combustion gases and the ambient air; the resulting pressure differential draws ambient air into the system through leaks such as warped doors or cracked casings/ductwork. Indications of excessive air leakage include elevated oxygen levels at the boiler outlet, elevated fuel consumption, and elevated gas temperatures.

The severity and source of the leaks determines whether the issue may be addressed as part of routine maintenance (e.g., door seal adjustments) or as part of planned outages (e.g., cracked casing repairs). Maintenance of boiler systems to minimize air leakage is a universally applicable approach.

The opportunity for improvement is a function of the leakage reduction and associated reduction in excess air. For example, a 3% change in oxygen levels in a gas-fired boiler represents efficiency improvements of approximately 4%. The expected efficiency improvements from reducing air leakage problems in industrial, commercial, and institutional boilers range from 1 to 4%. As part of the O&M practices, the air handling systems for each boiler will be periodically inspected for leaks.

Based on this information, the use of minimization of air infiltration is a technically feasible option for the auxiliary boilers at this source.

Boiler Blowdown Heat Exchange

Waste heat from the boiler blowdown stream can be recovered with a heat exchanger, a flash tank, or flash tank in combination with a heat exchanger. The resulting low pressure steam is most typically used in deaerators. Cooling the blowdown has the additional advantage of reducing the temperature of the liquids released into the sewer system.

Blowdown can be either intermittent bottom blowdown or continuous blowdown. Intermittent bottom blowdown may be sufficient if the feedwater is exceptionally pure. Intermittent blowdown is performed manually and therefore may result in wide fluctuations in blowdown patterns. Use of continuous rather than intermittent blowdown saves treated boiler water and can result in significant energy savings.

Expected efficiency improvements vary based on boiler blowdown rate and boiler pressure. The proposed natural gas boiler is a stand-by, auxiliary unit that is not intended to operate a significant number of hours. As such, a blowdown heat exchanger is not economically feasible.

Based on this information, the use of boiler blowdown heat exchange is not a technically feasible option for the auxiliary boilers at this source.

Condensation Return System

Hot condensate that is not returned to the boiler represents a corresponding loss of energy. Other benefits associated with an efficient condensate return system include reduced make-up water usage, water related treatment costs, boiler blowdown, and disposal costs. Energy savings

originate from the fact that most condensate is returned at relatively high temperatures (typically 130 to 225°F) compared to the cold makeup water (50 to 60°F) that must be heated, but must also account for the “steam flash loss” - the amount of saturated condensate that flashes off to steam when reduced to a lower pressure. Operation of the return condensate system depends on the specific boiler and water/condensate quality. Site-specific conditions and economic considerations must be addressed to determine whether it would be applicable, and, therefore, it is necessary to consider its viability on a case-by-case basis.

A further improvement on recovering the available energy of the condensate may be to use a heat exchanger (vent condenser) where the flashing steam is typically vented. Site-specific evaluation is necessary before determining the viability of this approach.

Expected efficiency improvements vary based on condensate temperature and percent recovery. The selected boiler will be equipped with a condensate return system.

Based on this information, the use of condensation return system is a technically feasible option for the auxiliary boilers at this source.

Minimization of Gas-side heat Transfer Surface Deposits

To minimize deposition on boiler heat transfer surfaces, the boiler must be operated within its design parameters. In practice, this may include the application of restrictions for fuel quality and firing rates. Boilers firing ash-laden fuels may be equipped with soot blowers to periodically remove the unavoidable deposition on the boiler walls and tubes and may utilize fuel treatment to mitigate the deposition propensity of the ash and combustion products.

Natural gas-fired boilers do not typically employ soot blowing systems given the reduced ash content of gaseous fuels.

Based on this information, the use of minimization of gas-side heat transfer surface deposits is a technically feasible option for the auxiliary boilers at this source.

Steam Line Maintenance

Heat losses through uninsulated lines and fittings can be significant. For example, 250 ft of uninsulated, 4-inch line with 300 psig steam would yield 2,800 MMBtu/yr, the equivalent of about 0.3 to 1.2% heat loss for boiler sizes between 25 and 100 MMBtu/hr. Similarly, the penalties for leaky valves/traps can represent measurable losses. General experience suggests that steam systems that do not include steam trap maintenance over a period of 3 to 5 years can result in 15 - 30% steam trap failures. Leaking traps should account for less than 5% of the trap population at plants with regular inspection and maintenance programs for steam traps.

Energy audits and maintenance procedures should highlight common maintenance items such as uninsulated steam distribution and condensate return lines and other fittings. Ensuring that all steam/condensate lines are properly insulated will yield measurable efficiency gains. Common practice suggests that surfaces over 120°F (steam and condensate return piping, fittings) should be insulated. Insulating jackets are available for valves, traps, flanges and other fittings. Leaky steam traps should be fixed as they represent another potentially significant source of wasted energy. Energy efficiency gains and cost depend on length and type of insulation required. Steam and hot water lines will be insulated. As part of the O&M practices, the steam system components and insulation will be periodically inspected for leaks.

Based on this information, the use of stream line maintenance is a technically feasible option for the auxiliary boilers at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Boiler Insulation	7% CO_2 Reduction
Efficient Burner Design	6% CO_2 Reduction
Air Preheat & Economizers	5% CO_2 Reduction
Improved Combustion Measures: optimization & Digital Control System	0.5-5% CO_2 Reduction
Minimization of Air Infiltration	4% CO_2 Reduction
Improved Combustion Measures: Combustion Tuning	3% CO_2 Reduction
Minimization of Gas-side heat Transfer Surface Deposits	1-3% CO_2 Reduction
Turbulators for Firetube Boilers	1% CO_2 Reduction
Steam Line Maintenance	
Operating and Maintenance Practices	
Condensation Return System	

Step 4: Evaluate Top Control Alternatives

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Proposed: NIPSCO - Schahfer Generating Station	073-49556-00008 (Pending)	N/A	Auxiliary Boilers (115 MMBtu/hr, each)	**Control Method:** Use of natural gas fuel Implement efficient boiler design Good combustion practices **Emission Limit:** 119,438 lb/MMcf (=117.10 lb/MMBtu)
Duke Energy Indiana, LLC	165-47430-00001 (02/14/2025)	IN-0382	Auxiliary Boiler (225 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** 115,400 ton/12 month period (=117.1 lb/MMBtu)
Wabash Valley Resources, LLC	167-45208-00091 (01/11/2024)	IN-0371	Auxiliary Boiler (217.65 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** 117.10 lb/MMBtu **Emission Limit 1:** 1183.50 MMcf/ 12 month period
Midwest Fertilizer Company LLC	129-44510-00059 05/06/2022	IN-0324	Auxiliary Boilers (218.60 MMBtu/hr)	**Control Method:** The boiler auxiliary boilers shall combust natural gas; shall be designed to achieve a minimum 80% thermal efficiency (HHV); shall be equipped with the following energy efficient design features: air inlet controls, heat recovery, condensate recovery, and blow down heat recovery **Emission Limit 1:** 59.71 ton/ MMcf, 3-hr average (= 119,420 lb/MMBtu = 117.1 lb/MMBtu) **Emission Limit 2:** 1877.39 MMcf/ 12 month rolling period
Nemadji Trail Energy Center	18-MMC-168 (09/01/2020)	WI-0300	Auxiliary Boiler (100 MMBtu/hr)	**Control Method:** Ultra-low NOx burners and flue gas recirculation Operate and maintain boiler according to manufacturer's recommendations Use pipeline quality natural gas **Emission Limit 1:** 160.0 lb/MMBtu, 12 month rolling average

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Chickahominy Power, LLC	52610-1 (06/24/2019)	VA-0332	Auxiliary Boiler (721 MMcf/yr)	**Control Method:** Use of natural gas High efficiency design and operation **Emission Limit 1:** 43,827 ton per 12 month rolling total (= 119.19 lb/MMBtu)
ESC Brooke County Power I, LLC - Brooke County Power Plant	R14-0035 (9/18/2018)	WV-0032	Auxiliary Boiler (111.9 MMBtu/hr)	**Control Method:** Use of natural gas **Emission Limit 1:** 14,768 lb/hr (=124.03lb/MMBtu) **Emission Limit 2:** 33,790 ton/yr
Novi Energy C4GT, LLC	52588 (04/26/2018)	VA-0328	Auxiliary Boiler (902 MMcf/yr)	**Control Method:** Good Combustion practices **Emission Limit 1:** 53,863 ton per 12 month rolling period (= 117.1 lb/MMBtu)
Tennessee Valley Authority TVA - Johnsonville Cogeneration	972969 (02/01/2018)	TN-0164	Auxiliary Boiler (450.0 MMBtu/yr)	**Control Method:** Efficiency design Good Combustion practices Good operation and maintenance practice **Emission Limit 1:** 117.1 lb/MMBtu, 12 month average
Filer City Station Limited Partnership - Filer City Station	66-17 (11/17/2017)	MI-0427	Auxiliary Boiler (182.0 MMBtu/hr)	**Control Method:** Good Combustion practices **Emission Limit 1:** 93,346 ton per 12 month rolling period (= 117.1 lb/MMBtu)
Midwest Fertilizer Company	129-36943-00059 (03/23/2017)	IN-0263	Auxiliary Boiler (218.60 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** 59.71 ton/ MMcf, 3-hr average (= 119,420 lb/MMBtu = 117.1 lb/MMBtu) **Emission Limit 2:** 1877.39 MMcf/ 12 month rolling period
Indeck Niles, LLC	75-16 (01/04/2017)	MI-0423	Auxiliary Boiler (182.0 MMBtu/hr)	**Control Method:** Energy efficiency measures Use of low carbon fuel **Emission Limit 1:** 93,346 ton per 12 month rolling period (=117.1 lb/MMBtu)
Lake Charles Methanol Facility	PSD-LA-803(M1) 06/30/2016	LA-0305	Auxiliary Boiler (225 MMBtu/hr)	**Control Method:** Good Combustion practices Good equipment design **Emission Limit 1:** --
Virginia Electric and Power Company - Greensville Power Station	52525 (06/17/2016)	VA-0325	Auxiliary Boiler (185.0 MMBtu/hr)	**Control Method:** Natural gas fuel High efficiency design and operation **Emission Limit 1:** 117.10 lb/MMBtu
Tennessee Valley Authority - Johnsonville Cogeneration	970816F (04/19/2016)	TN-0162	Auxiliary Boiler (450.0 MMBtu/hr)	**Control Method:** High design Good combustion practices Good operation and maintenance practices **Emission Limit 1:** 117.10 lb/MMBtu

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Magnolia LNG Facility	PSD-LA-792 (03/21/2016)	LA-0307	Auxiliary Boiler (171.0 MMBtu/hr)	**Control Method:** Good combustion, operation, and maintenance practices Use of natural gas fuel **Emission Limit 1:** --
Golden Pass LNG Export Terminal	116055, PSDTX1386, GHGPSDTX100 (09/11/2015)	TX-0766	Auxiliary Boiler (240.0 MMBtu/hr)	**Control Method:** Equipment specification & work practices Good combustion practices Use of low carbon fuel **Emission Limit 1:** 1,440.0 hr/yr

The most stringent RBLC and permit entries for GHG control are provided above. The majority of the auxiliary boilers have an annual ton per year limit (based on annual gas use) or pounds per MMBtu.

The proposed BACT limit for GHGs for each of the auxiliary boilers AUX1 and AUX2 is 119,438 lb/MMscf (= 117.10 lb/MMBtu), which is in line with the lowest BACT limits for other recent RBLC similar sources.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the auxiliary boilers AUX1 and AUX2 shall be as follows:

(1) CO_2e emissions from each of the auxiliary boilers AUX1 and AUX2 shall not exceed 119,438 lb/MMcf (GWPs per July 29, 2025).

(2) CO_2e emissions from each of the auxiliary boilers AUX1 and AUX2 shall be controlled through the use of natural gas fuel, implement efficient boiler design, and good combustion practices.

BACT Analysis – Diesel Emergency Generators

Emission Unit Description

Two (2) 2,500 kW diesel-fired certified emergency generators, identified as EDGCC1 and EDGCC2, approved in 2026 for construction, each with a maximum rated capacity of 3,353 hp, using no control, and exhausting to stacks SEDGCC1 and SEDGCC2.

[Under 40 CFR 60, Subpart IIII, these units are affected facilities]
[Under 40 CFR 63, Subpart ZZZZ, these units are affected sources]

VOC BACT Analysis – Diesel Emergency Generators

This section addresses VOC emissions from combustion of diesel fuel in the proposed RICE units. In ultra-low sulfur diesel (“ULSD”) emergency engines, VOC emissions are a result of incomplete combustion of carbon contained within the fuel. Properly designed and operated engines typically emit low levels of VOC. High levels of VOC emissions could result from poor design or sub-optimal firing conditions.

The emergency generator engines will be ‘affected facilities’ subject to the standards for emergency engines under 40 CFR Part 60 Subpart IIII. The emergency generator engine,

pursuant to 40 CFR § 60.4205(b), will be required to meet the NOx + NMHC emission standard established for nonroad engines of the same model year 40 CFR § 60.4202. Per 40 CFR §60.4202 (b)(2), specific limitations in 40 CFR Part 1039 are applicable to the emergency engine that is not a fire pump. The emission standard is a specification of 6.4 g/kW-hr (specified for NOX + NMOC), as determined by the engine manufacturer.

Step 1: Identify All Potentially Available Control Technologies

Using RBLC search and permit review results, the following potentially available control technologies for controlling VOC emissions were identified:

(1) Nonselective Catalytic Reduction
(2) Lean NOx Catalyst
(3) Diesel Oxidation Catalyst (DOC)
(4) Diesel Particulate Filters
(5) Usage Limitation
(6) Good Combustion Practices

Step 2: Eliminate Technically Infeasible Options

Nonselective Catalytic Reduction

Nonselective Catalytic Reduction (NSCR) involves placing a catalyst in the exhaust stream of the engine and can simultaneously reduce NOx, CO, and VOCs. The reaction requires that the oxygen levels be kept low and that the engine be operated at fuel-rich air-to-fuel ratios. Under this condition, in the presence of the catalyst, NOx is reduced by the CO, resulting in nitrogen and CO_2. CO is oxidized to CO_2 and hydrocarbons are oxidized to CO_2 and water vapor. The catalyst used is generally a mixture of platinum and rhodium, with optimal catalyst operating temperatures between 800 and 1,200°F. CO can be reduced by 50-90% under rich-burn conditions.

The application of NSCR requires fuel-rich engine operation and is, therefore, limited to rich-burn engines (gasoline). Diesel engines tend to operate under lean-burn conditions. Therefore, NSCR is not technically feasible.

All other control technologies are considered to be technically feasible.

Lean NOx Catalyst

Lean NOx catalysts use a porous material made of zeolite with a precious metal or base metal catalyst. NOx emissions are controlled by injecting a small amount of diesel fuel or other hydrocarbon reductant into the exhaust upstream of the catalyst, which reduces NOx to N2. The zeolites provide sites to attract the hydrocarbons to facilitate the NOx reduction reactions. Lean NOx catalyst are also capable for reducing VOC emissions around 60%.

Diesel Oxidation Catalyst (DOC)

Diesel oxidation catalysts usually consist of a stainless steel canister that contains a honeycomb structure onto which catalytic metals such as platinum or palladium are coated. The diesel oxidation catalyst can reduce particulate, VOC and CO emissions by oxidizing them at an adequate exhaust temperature to become CO2 and water. VOC emissions can be reduced by 60 - 99%.

Diesel Particulate Filters

Diesel particulate filters consist of a filter in the exhaust stream designed to collect a significant fraction of the particulate emissions while allowing the exhaust gases to pass through. After a pre-established pressure drop is reached, the buildup of particulate is often incinerated through the use of heat provided by a variety of sources such as fueled burners, electric heaters, engine intake and throttling. The filter is then clean and regenerated for further use. Catalytic coatings on diesel particulate filters can also reduce CO and VOC emissions. VOCs can be reduced by 60 - 80%.

Usage Limitation

Restrictions on the amount of fuel or hours of operation can assist in limiting all emissions.

Good Combustion Practices

VOC emissions are generated through incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form where fuel will partially combust, resulting in VOC and unburned hydrocarbons that exit with the exhaust. Maintaining optimum combustion efficiency or implementing appropriate maintenance procedures are examples of good combustion practices.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the technical feasibility analysis above, the remaining control technologies may be ranked as follows for controlling VOC emissions from the emergency generator:

Diesel Oxidation Catalyst	60-99% VOC Reduction
Diesel Particulate Filter	60-80% VOC Reduction
Lean NOx Catalyst	60% VOC Reduction
Good Combustion Practices	Reduction Varies

To be considered technically feasible, a control technology must either be successfully demonstrated on a unit or, if not demonstrated, then be "available and applicable". A technology is considered "available" if it can be obtained by the applicant through commercial channels. An available technology is considered "applicable" if it can reasonably be installed and operated on the unit in question.

The feasibility of each of the potentially applicable control options identified is evaluated below:

(1) Diesel oxidation catalysts (DOC) have been applied in diesel engine applications where engines are operated primarily at high capacity for extended periods of time for industrial and power generation purposes, such as “demand response” or “peak shaving” programs with revenue incentives, in large installations, or in non-attainment areas. DOCs effectiveness is limited in applications requiring quick startups and short operating durations, such as the required routine readiness testing and maintenance, because the practice is to minimize the length of these periods. Therefore, the application of DOC technology can be considered to be not technically feasible due to the sporadic nature of the emergency engines and is not considered further in this analysis.

(2) Diesel particulate filters are not considered technically feasible because engines that are operating intermittently for testing and maintenance purposes are unlikely to achieve and sustain the necessary exhaust temperatures to achieve consistent reductions. The filters will clog, reduce engine power, and may cause a malfunction.

Step 4: Evaluate Top Control Alternatives

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as IDEM, OAQ permits issued to date.

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Proposed: NIPSCO - Schahfer Generating Station	073-49556-00008 (Pending)	N/A	Emergency Generators (3,353 hp, each; 2,500 kW)	**Control Method:** Use of equipment design standard; Comply with 40 CFR 60, Subpart IIII **Emission Limit 1:** 6.4 g/kW-hr (4.8 g/hp-hr)
Corpus Christi Liquification, LLC - Stage 3	PSDTX1496M1, GHGPSDTX157M1 (05/30/2025)	TX-0976	Emergency Generators	**Control Method:** EPA Tier 2, limited to 100 hours per year of non-emergency operation, engine design and certification in accordance with standards, limited operational hours, and proper operation and maintenance. **Emission Limit:** --
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	4 Black Start Emergency Generators (3000 kWe, each)	**Control Method:** Good combustion practices Low sulfur fuel **Emission Limit 1:** 0.24 g/hp-hr **Emission Limit 2:** 2.29 lb/hr (4 engines)
			Plant Emergency Generator (1500 kWe)	**Control Method:** Good combustion practices Low sulfur fuel **Emission Limit 1:** 0.24 g/hp-hr **Emission Limit 2:** 1.06 lb/hr
Duke Energy Indiana, LLC	165-47430-00001 (02/14/2025)	IN-0382	Emergency Generators (2,000-hp)	**Control Method:** -- **Emission Limit 1:** 6.40 g/kW-hr, 3-hr average
Shintech Louisiana, LLC - Shintech Plaquemine Plant 4	PSD-LA-857 (12/16/2024)	LA-0403	Emergency Generator (2346 hp)	**Control Method:** Compliance with 40 CFR 60 Subpart IIII **Emission Limit 1:** 6.27 lb/hr **Emission Limit 2:** 6.40 g/kW-hr
			Emergency Generator (2012 hp)	**Control Method:** Compliance with 40 CFR 60 Subpart IIII **Emission Limit 1:** 5.38 lb/hr **Emission Limit 2:** 0.17 ton/yr **Standard Emission Limit :** 6.40 g/kW-hr
Shintech Louisiana, LLC - Shintech Plaquemine Plant 2	PSD-LA-856 (12/16/2024)	LA-0405	Emergency Generator (535 hp)	**Control Method:** Compliance with 40 CFR 60 Subpart IIII

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
				Emission Limit 1: 6.40 g/kW-h
XCEL Energy Blue Lake	13900010-105 (08/07/2024)	MN-0095	Emergency Generators (1049 hp, each)	**Control Method:** Emergency classification, Hourly restriction, Good combustion practices, NSPS compliance **Emission Limit 1:** 4.80 g/hp-h, 24 hr rolling average (=6.40 g/kW-h) **Emission Limit 1:** 11.03 lb/hr, 3-hr average
			Emergency Generators (772 hp, each)	**Control Method:** Emergency classification, Hourly restriction, Good combustion practices, NSPS compliance **Emission Limit 1:** 4.80 g/hp-h, 24 hr rolling average (=6.40 g/kW-h) **Emission Limit 1:** 8.12 lb/hr, 3-hr average
Mitsubishi Chemical America, Inc - MCA Geimar Site	PSD-LA-850 (07/24/2024)	LA-0406	Emergency Generator (1140 hp)	**Control Method:** Proper equipment design Good combustion practices Use ultra-low sulfur diesel fuel Compliance with 40 CFR 60, Subpart IIII **Emission Limit 1:** 4.80 g/hp-hr, NMEHC + NOx (=6.40 g/kW-h)
Lansing Board of Water and Light-Delta Energy Park	71-24 (06/27/2024)	MI-0459	Emergency Generator (762 hp)	**Control Method:** Good combustion practices **Emission Limit 1:** 6.40 g/kW-hr, NMEHC + NOx
Cronus Chemicals, LLC	19110020 (12/21/2023)	IL-0134	Emergency Generator (3985 hp)	**Control Method:** -- **Emission Limit 1:** 6.40 g/kW-hr, 3-hr average, NMHC + NOx **Emission Limit 2:** 75.0 hr/yr, operating limit
Koch Methanol (KME) Facility	PSD-LA-851 (12/20/2023)	LA-0401	Emergency Generator (2923 hp)	**Control Method:** Compliance with 40 CFR 60, Subpart IIII **Emission Limit 1:** 2.06 lb/hr
			Emergency Generator (3634 hp)	**Control Method:** Compliance with 40 CFR 60, Subpart IIII **Emission Limit 1:** 2.29 lb/hr
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Emergency Generator (1490 hp)	**Control Method:** Good combustion practices include operational and design elements **Emission Limit 1:** 0.32 g/hp-hr

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
				Standard Emission Limit: 500.0 hours per year
Nucor Steel	107-45480-00038 (03/30/2023)	IN-0359	Emergency Generator (3000 hp)	**Control Method:** Certified engine **Emission Limit 1:** 0.32 g/hp-hr
Commonwealth LNG Facility	PSD-LA-841 (03/28/2023)	LA-0324	Emergency Generator (4290 kW)	**Control Method:** Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage **Emission Limit 1:** 0.322 g/hp-h
Energy Texas, Inc Orange County Advanced Power Station	166032 PSDTX1598 GHGPSDTX210 (03/13/2023)	TX-0939	Emergency Generator (18.70 MMBtu/hr)	**Control Method:** Good combustion practices Limited to 100 hours per year **Emission Limit 1:** 0.0010 lb/hp hr (= 0.46 g/hp)
Nucor Corporation - Nucor Steel Arkansas	1139-AOP-R27 (11/21/2022)	AR-0177	Emergency Generator (3634 hp)	**Control Method:** -- **Emission Limit 1:** 0.80 g/kW-hr (=0.6 g/hp)
Kronospan, LLC	301-0079 (09/21/2022)	AL-0337	Emergency Generator	**Control Method:** Catalyst **Emission Limit 1:** 1.33 lb/hr
Intel Ohio Site	P0132323 (09/20/2022)	OH-0387	Emergency Generator (5051 hp)	**Control Method:** Certified Tier 2 engines Good combustion practices **Emission Limit 1:** 0.40 g/kW-h (=0.3 g/hp) **Emission Limit 2:** 0.30 lb/hr 0.06 tons per 12-month rolling period
Marshall Energy Center - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Emergency Generator (1341 hp)	**Control Method:** Good combustion practices **Emission Limit 1:** 0.86 lb/hr
Marshall Energy Center - MEC North, LLC	168-17B (06/23/2022)	MI-0452	Emergency Generator (1341 hp)	**Control Method:** Good combustion practices **Emission Limit 1:** 0.86 lb/hr
Magnolia Power - Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Emergency Generator (2937 hp)	**Control Method:** Good combustion practices Compliance with 40 CFR 60 Subpart IIII standards Use of ultra-low sulfur diesel fuel **Emission Limit 1:** 4.80 g/hp-h (NMHC + NOx) (=6.40 g/kW-h)
Midwest Fertilizer Company LLC	129-44510-00059 (05/06/2022)	IN-0324	Emergency Generator (3600 hp)	**Control Method:** Good combustion practices **Emission Limit 1:** 0.35 g/hp-hr (= 0.47 g/kW-h)

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
				Emission Limit 2: 500 hour per year
Mountain State Clean Energy, LLC Maidsville	R14-0038 (01/05/2022)	WV-0033	Emergency Generator (2100 hp)	**Control Method:** Good combustion practices **Emission Limit 1:** 0.46 lb/hr **Emission Limit 2:** 6.40 g/kW (NMHC + NOx)
NRG Cedar Bayou LLC - Unit 5	160538, PSDTX1528, GHGPSDTX204 (03/17/2021)	TX-0915	Emergency Generator	**Control Method:** Limited 500 hrs/yr operation **Emission Limit 1:** 0.50 g/hp-h (= 0.67 g/kW-h)
Lake Charles LNG Export Terminal	PSD-LA-838 (09/03/2020)	LA-0383	Emergency Generator	**Control Method:** Comply with 40 CFR 60, Subpart IIII **Emission Limit 1:** --
Nemadji Trail Energy Center	18-MMC-168 (09/01/2020)	WI-0300	Emergency Generator (1,490 hp)	**Control Method:** Operation limited to 500 hours/year and operate and maintain generator according to the manufacturer's recommendations **Emission Limit 1:** 0.32 g/hp-h (= 0.43 g/kW-h)
Riverview Energy Corporation	T147-39554-00065 (06/11/2019)	IN-0317	Emergency Generator (2800 hp)	**Control Method:** Tier II diesel engine Good combustion practices **Emission Limit 1:** 6.40 g/kWh-h (NMHC + NOx)
DTE Electric Company - Belle River Combined Cycle Power Plant	19-18 (07/16/2018)	MI-0435	Emergency Generator (2.00 MW)	**Control Method:** State of the art combustion design **Emission Limit 1:** 1.80 lb/hr
SIO International Wisconsin, Inc - Energy Plant	18-JJW-022 (04/24/2018)	WI-0286	Emergency Generator (2346 hp)	**Control Method:** Good combustion practices **Emission Limit 1:** 0.56 g/kWh (= 0.42 g/hp-h)
Harrison Power	P0122266 (04/19/2018)	OH-0377	Emergency Generator (1,860 hp) (1,387 kW)	**Control Method:** Good compliance practices Compliance with 40 CFR Part 60, Subpart IIII **Emission Limit 1:** 19.68 lb/hr (NMHC + NOx) **Emission Limit 2:** 0.98 ton/yr **Standard Emission Limit :** 4.80 g/hp-h (=6.40 g/kW-h) all emissions limits are for Non-methane hydrocarbon (NMHC) + NOx emissions. 0.98 ton/yr

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Long Ridge energy Generation LLC - Hannibal Power	P0122829 (11/7/2017)	OH-0375	Emergency Generator (2,206 hp) (1,645 kW)	**Control Method:** Good combustion design **Emission Limit 1:** 24.71 lb/hr (NMHC + NOx) **Emission Limit 2:** 1.24 ton/yr (NMHC + NOx) **Standard Emission Limit :** 4.80 g/hp-h (NMHC + NOx) (=6.40 g/kW-h)
Guernsey Power Station LLC	P0122594 (10/23/2017)	OH-0374	Emergency Generator (2206 hp)	**Control Method:** Good combustion practices **Emission Limit 1:** 23.21 lb/hr (NMHC + NOx) **Emission Limit 2:** 1.16 ton/yr (NMHC + NOx) **Standard Emission Limit :** 4.8 g/hp-h (NMHC + NOx) (=6.40 g/kW-h)
Oregon Energy Center	P0121049 (09/27/2017)	OH-0372	Emergency Generator (1529 hp)	**Control Method:** State of art combustion design **Emission Limit 1:** 2.00 lb/hr **Emission Limit 2:** 0.05 ton/12 month rolling period **Standard Emission Limit :** 0.79 g/kW-hr (0.59 g/b-hp-h) (NMHC) + NOX emissions shall not exceed 6.40 g/kW-hr
Trumbull Energy center	P0122331 (09/07/2017)	OH-0370	Emergency Generator (1529 hp)	**Control Method:** State of art combustion design **Emission Limit 1:** 2.00 lb/hr **Emission Limit 2:** 0.05 ton/12 month rolling period **Standard Emission Limit :** 0.79 g/kW-hr (0.59 g/b-hp-h) (NMHC) + NOX emissions shall not exceed 6.40 g/kW-hr
South Field Energy LLC	P0119495 (09/23/2016)	OH-0367	Emergency Generator (2,947 hp)	**Control Method:** State of the art combustion design **Emission Limit 1:** 3.84 lb/hr **Emission Limit 2:** 0.96 ton/yr (12 month rolling) Standard limit (metric) is 0.79 g/kW-hr. NSPS: (NMHC) + NOx emissions shall not exceed 6.40 g/kW-hr
Entergy Louisiana, LLC St. Charles Power Station	PSD-LA-804 (08/31/2016)	LA-0313	Emergency Generator (2,584 hp)	**Control Method:** Good combustion practices **Emission Limit 1:** 27.34 lb/hr **Emission Limit 2:** 6.84 ton/yr **BACT Limit**: 4.80 g/Bhp-hr (NMHC + NOx) (=6.40 g/kW-h)

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Virginia Electric and Power Company Greensville Power Station	52525 (06/17/2016)	VA-0325	Emergency Generator (3000 kW)	**Control Method:** Good combustion practices **Emission Limit 1:** 6.40 g/kW-hr (NMHC + NOx)
Cricket Valley Energy Center	3-1326-00275/00009 (02/03/2016)	NY-0130	Emergency Generator (3000 kW)	**Control Method:** Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations **Emission Limit 1:** 0.11 g/bhp-hr (= 0.15 g/kW-h)

No add-on controls were seen in the review of other similar BACT determinations. Additionally, the EPA determined in 40 CFR Part 60, Subpart IIII that controls were not necessary for emergency engines with a displacement less than 30 liters per cylinder.

All of the emergency generator engines listed in the RBLC have BACT specified as compliance with the 40 CFR 60 Subpart IIII limits. None of the emergency engines have any post-combustion controls. NIPSCO is proposing compliance with the 40 CFR 60 Subpart IIII limits.

The emergency engines to be installed at the NIPSCO facility will be certified by the equipment manufacturer to meet the applicable emission standards for nonroad, compression-ignition engines, as codified in 40 CFR Part 60 Subpart IIII and at 40 CFR Part 1039.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the emergency generator shall be as follows:

(a) VOC emissions from each emergency generators (EDGCC1 and EDGCC2) shall be controlled good combustion practices including the installation of an equipment design standard and compliance with the requirements of 40 CFR 60, Subpart IIII.

(b) NMHC + NOx emissions from each emergency generator (EDGCC1 and EDGCC2) shall not exceed 6.4 g/ kW-hr.

GHG BACT Analysis – Diesel Emergency Generators

Step 1: Identify Potential Control Technologies

The available GHG emission control strategies for emergency generator that were analyzed as part of this BACT analysis include:

(a) Carbon Capture and Storage (CCS)
(b) Good Engineering Design and fuel Efficiency Design
(c) Fuel selection
(d) Good Combustion, Operating, and Maintenance Practices

Step 2: Eliminate Technically Infeasible Options

Carbon Capture and Storage (CCS)

Carbone Capture and Storage (CCS) involves separation and capture of CO2 from the combustion exhaust gases using physical or chemical adsorption, pressurization of the captured CO2, transportation of the captured CO2 via pipeline, and injection and long-term geologic storage of the captured CO2. CCS technology, specifically post-combustion CO2 capture technology, is not commercially available as it has not yet been successfully implemented on a large scale basis.

According to the CCS task force report, CO2 capture technology is being operated at a small scale at several coal-fired power plants and there are plans to implement this technology on a larger scale at several coal-fired power plants in the coming years. However, CCS technology, specifically post-combustion CO2 capture technology, is not commercially available and has not yet been successfully implemented on a large-scale basis.

For large projects, off-site CO2 storage generally relies upon a third-party CO2 pipeline system in order to transport the CO2 to a repository. Pipelines are the most common and theoretically feasible method for transporting large quantities of CO2. Specialized designs may be required for CO2 pipelines, particularly if supercritical CO2 is being transported. Transport of CO2 by pipeline is a demonstrated technology. Constructing such a pipeline for dedicated use by a single facility often will make a project economically infeasible. However, such an option may be effective if both adequate storage capacities exist in close proximity to the source, and reasonable transportation prices can be arranged with the pipeline operator.

Based on the information reviewed for this BACT determination, CCS has been considered technically infeasible for potential CO2 (GHG) control.

Good Engineering Design and Fuel Efficient Design

NIPSCO will install an engine meeting the latest efficiency and pollutant performance standards specified in NSPS Part 60 Subpart IIII and NESHAP Part 63 Subpart ZZZZ. The diesel engines are built with automatic control of the air to fuel ratio that ensures that these operate when needed and meet the applicable standards.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of good engineering design and fuel-efficient design is a technically feasible option for the emergency engines under the project.

Fuel Selection

The only technically feasible fuel for the emergency generators is diesel fuel. While a natural gas-fired emergency generators may provide lower GHG emissions per unit of power output, natural gas is not considered a technically feasible fuel for the emergency generators since it will need to be used in the event of fire, when natural gas supplies may be interrupted.

Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option for maintaining the combustion efficiency of the emergency equipment. Good combustion practices include proper maintenance and tune-up of the generator per the manufacturer’s specifications.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Good engineering design and fuel-efficient design are the only technically feasible technologies to minimize GHG emissions.

Step 4: Evaluate Top Control Alternatives

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Proposed: NIPSCO - Schahfer Generating Station	073-49556-00008 (Pending)	N/A	Emergency Generators (3,353 hp, each; 2,500 kW)	**Control Method:** Use of equipment design standards Comply with 40 CFR 60, Subpart IIII **Emission Limit 1:** 163.6 lb/MMBtu
Corpus Christi Liquification, LLC - Stage 3	PSDTX1496M1, GHGPSDTX157M 1 (05/30/2025)	TX-0976	Emergency Generators	**Control Method:** EPA Tier 2, limited to 100 hours per year of non-emergency operation, engine design and certification in accordance with standards, limited operational hours, and proper operation and maintenance. Emission Limit: --
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	4 Black Start Emergency Generators (3000 kWe, each)	**Control Method:** -- **Emission Limit:** CO2e emissions from the entire source shall not exceed 1,115,606 tons per twelve (12) months
			Plant Emergency Generator (1500kWe)	**Control Method:** good engineering design, Fuel efficient design, Limited operating hours **Emission Limit:** CO2e emissions from the entire source shall not exceed 1,115,606 tons per twelve (12) months
Duke Energy Indiana, LLC	165-47430-00001 (02/14/2025)	IN-0382	Emergency Generators (2,000-hp)	**Control Method:** Good combustion practices **Emission Limit 1:** --
Shintech Louisiana, LLC - Shintech Plaquemine Plant 4	PSD-LA-857 (12/16/2024)	LA-0403	Emergency Generator (2346 hp)	**Control Method:** energy efficiency measures: Improved Combustion Measures, Insulation, and Minimization of Air Infiltration **Emission Limit 1:** --
			Emergency Generator (2012 hp)	**Control Method:** energy efficiency measures: Improved Combustion Measures, Insulation, and Minimization of Air Infiltration **Emission Limit** 1**:** **--**

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Cronus Chemicals, LLC	19110020 (12/21/2023)	IL-0134	Emergency Generator (3985 hp)	**Control Method:** -- **Emission Limit 1:** 160.0 ton/yr **Emission Limit 2:** 75.0 hr/yr, operating limit
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Emergency Generator (1490 hp)	**Control Method:** Selection of the most efficient reciprocating internal combustion engine and minimizing the hours of operation limits greenhouse gas emissions. EPA Tier 2 certified reciprocating internal combustion engine and limiting its hours of operation to 500 hours per each 12 consecutive calendar months **Emission Limit 1:** 500.0 hours per year
Maple Creek Energy LLC	T153-45909-00056 (06/19/2023)	IN-0365	Emergency generator (2,012 hp)	**Control Method:** -- **Emission Limit:** 625 ton/yr
Nucor Steel	107-45480-00038 (03/30/2023)	IN-0359	Emergency Generator (3000 hp)	**Control Method:** Good engineering design and manufacturer's recommended operating and maintenance procedures **Emission Limit 1:** 163.60 lb/MMBtu **Emission Limit 1:** 920.0 ton/yr
Energy Texas, Inc Orange County Advanced Power Station	166032 PSDTX1598 GHGPSDTX210 (03/13/2023)	TX-0939	Emergency Generator (18.70 MMBtu/hr)	**Control Method:** Good combustion practices Limited to 100 hours per year **Emission Limit 1:** --
Lansing Board of Water and Light - LBWL Erickson Station	74-18D (12/20/2022)	MI-0454	Emergency Generator EUEMGD (4474 kW)	**Control Method:** Low carbon fuel (pipeline quality natural gas) Good combustion practices and energy efficiency measures. **Emission Limit:** 590 ton/12 month rolling average
Nucor Corporation - Nucor Steel Arkansas	1139-AOP-R27 (11/21/2022)	AR-0177	Emergency Generator (3634 hp)	**Control Method:** -- **Emission Limit 1:** 163.6 lb/MMBtu
Intel Ohio Site	P0132323 (09/20/2022)	OH-0387	Emergency Generator (5051 hp)	**Control Method:** Good combustion practices proper maintenance and operation **Emission Limit 1:** 163.6 lb/MMBtu of actual heat input
Lincoln Land Energy Center (A/K/A Ember clear)	18040008 (07/29/2022)	IL-0133	Emergency Engines (1250 kW)	**Control Method:** -- **Emission Limit:** 508.0 ton/yr

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Marshall Energy Center - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Emergency Generator (1341 hp)	**Control Method:** Good combustion practices **Emission Limit 1:** 383.0 ton/ 12 month rolling period
Marshall Energy Center - MEC North, LLC	168-17B (06/23/2022)	MI-0452	Emergency Generator (1341 hp)	**Control Method:** Good combustion practices **Emission Limit 1:** 383.0 ton/ 12 month rolling period
Magnolia Power - Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Emergency Generator (2937 hp)	**Control Method:** Good combustion practices Compliance with 40 CFR 60 Subpart IIII standards Use of ultra-low sulfur diesel fuel **Emission Limit 1:** 163.61 lb/MMBtu (74.21 kg/MMBtu)
Midwest Fertilizer Company LLC	129-44510-00059 (05/06/2022)	IN-0324	Emergency Generator (3600 hp)	**Control Method:** Good combustion practices **Emission Limit 1:** 1044.0 ton/12 month period **Emission Limit 2:** 500 hour per year
NRG Cedar Bayou LLC - Unit 5	160538, PSDTX1528, GHGPSDTX204 (03/17/2021)	TX-0915	Emergency Generator	**Control Method:** Limited 500 hrs/yr operation **Emission Limit 1:** --
Lansing Board of Water and Light	74-18A (01/07/2021)	MI-0447	Emergency Engine (EUEMGD) (2,206 HP)	**Control Method:** Low carbon fuel (pipeline quality natural gas) Good combustion practices and energy efficiency measures. **Emission Limit 1:** 590 ton/12 month rolling average
Lake Charles LNG Export Terminal	PSD-LA-838 (09/03/2020)	LA-0383	Emergency Generator	**Control Method:** Comply with 40 CFR 60, Subpart IIII **Emission Limit 1:** --
Nemadji Trail Energy Center	18-MMC-168 (09/01/2020)	WI-0300	Emergency Generator (1490 hp)	**Control Method:** Certified to at least meet EPA's criteria for Tier 2 reciprocating internal combustion engines and the 40 CFR 60, Subpart IIII emission limitations, operation limited to 500 hours/year, and operate and maintain generator according to the manufacturer's recommendations **Emission Limit 1:** --
Alaska Gasline Development Corporation	AQ1524CPT01 (08/13/2020)	AK-0085	Emergency Generator (186.60 gph)	**Control Method:** Good combustion practices and limit operation to 500 hours per year **Emission Limit 1:** 163.6 lb/MMBtu, 3 hours average

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
FG LA LLC	PSD-LA-812 (01/06/2020)	LA-0364	Emergency Generator (550 hp)	**Control Method:** Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage. **Emission Limit 1:** --
Indeck Niles, LLC	75-16B (11/26/2019)	MI-0445	Emergency Generator (22.68 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** 928 ton/12 month rolling period
Chickahominy Power LLC	52610-1 (06/24/2019)	VA-0332	Emergency Generator (300 kW)	**Control Method:** Good combustion practices, High efficiency design, Use of ultra-low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw. **Emission Limit 1:** 1203 ton/12 month rolling total
Riverview Energy Corporation	T147-39554-00065 (06/11/2019)	IN-0317	Emergency Generator (2800 hp)	**Control Method:** Tier II diesel engine Good combustion practices **Emission Limit 1:** 811.0 ton/12 month rolling period
Jackson Generation, LLC	17040013 (12/31/2018)	IL-0130	Emergency Generator (1500 kW)	**Control Method:** -- **Emission Limit:** 225 ton/yr
Lansing Board of Water and Light - LBWL Erickson Station	74-18 (12/21/2018)	MI-0441	EUEMGD1-A emergency engine (1500 hp)	**Control Method:** Good combustion practices and energy efficiency measures. **Emission Limit 1:** 406 ton/12 month rolling period
			EUEMGD2-A Emergency Generator (6000 hp)	**Control Method:** Good combustion practices and energy efficiency measures. **Emission Limit 1:** 1590 ton/12 month rolling period
			EUFPRICE-A Emergency Generator (315 hp)	**Control Method:** Good combustion practices and energy efficiency measures. **Emission Limit 1:** 20 ton/12 month rolling period
Marshall Energy Center LLC - MEC North, LLC and MEC South, LLC	167-17 and 168-17 (06/29/2018)	MI-0433	(North Plant): Emergency Generator (1341 hp)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 383 ton/12 month rolling period
			(South Plant): Emergency Generator (1341 hp)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 383 ton/12 month rolling period

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Novi Energy C4GT, LLC	52588 (04/26/2018)	VA-0328	Emergency Diesel GEN	**Control Method:** Use of S15 ULSD and high efficiency design and operation **Emission Limit:** 981 ton/12 month rolling total
SIO International Wisconsin, Inc - Energy Plant	18-JJW-017 (04/24/2018)	WI-0284	Emergency Generator (2346 hp)	**Control Method:** Good combustion practices Use of ultra-low sulfur fuel **Emission Limit 1:** --
SIO International Wisconsin, Inc - Energy Plant	18-JJW-022 (04/24/2018)	WI-0286	Emergency Generator (2346 hp)	**Control Method:** Good combustion practices Use of ultra-low sulfur fuel **Emission Limit 1:** --
Harrison Power	P0122266 (04/19/2018)	OH-0377	Emergency Generator (1860 hp)	**Control Method:** Efficient design and proper maintenance and operation **Emission Limit:** 109.2 tpy (12 month rolling average)
Long Ridge Energy Generation LLC - Hannibal Power	P0122829 (11/07/2017)	OH-0375	Emergency Generator (2206 hp)	**Control Method:** Efficient design **Emission Limit 1:** 116.8 ton/yr (12 month rolling average)
Guernsey Power Station LLC	P0122594 (10/23/2017)	OH-0374	Emergency Generator (2206 hp)	**Control Method:** Good operating practices (proper maintenance and operation) **Emission Limit 1:** 120 ton/12 month rolling period
Oregon Energy Center	P0121049 (09/27/2017)	OH-0372	Emergency Generator (1529 hp)	**Control Method:** State of the art combustion design **Emission Limit:** 445.0 ton/12 month rolling period
Trumbull Energy center	P0122331 (09/07/2017)	OH-0370	Emergency Generator (1529 hp)	**Control Method:** Efficiency design **Emission Limit 1:** 445.0 ton/12 month rolling period
Massachusetts Institute of Technology MIT Central Utility Plant	NE-15-018 (06/21/2017)	MA-0043	Emergency Generator (19.04 MMBtu/hr)	**Control Method:** -- **Emission Limit 1:** 163.61 lb/MMBtu **Emission Limit 1:** 3115.0 lb/hr CO2e shall not exceed 467.3 ton/12 month rolling period
Indeck Niles, LLC	75-16 (01/04/2017)	MI-0423	EUEMENGINE Emergency Generator (2922 hp)	**Control Method:** Good combustion practices **Emission Limit 1:** 928 ton/12 month rolling period
South Field Energy LLC	P0119495 (09/23/2016)	OH-0367	Emergency Generator (2947 hp)	**Control Method:** Efficient design **Emission Limit:** 858 ton/yr (12 month rolling average)

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Entergy Louisiana, LLC St. Charles Power Station	PSD-LA-804 (08/31/2016)	LA-0313	Emergency Generator (2,584 hp)	**Control Method:** Good combustion practices **Emission Limit:** --
Virginia Electric and Power Company Greensville Power Station	52525 (06/17/2016)	VA-0325	Emergency Generator (3000 kW)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 163.6 lb/MMBtu **Emission Limit 2:** 1178 ton/12 month rolling period
Lackawanna Energy Center, LLC	35-00069A (12/23/2015)	PA-0309	Emergency Generator (2000 kW)	**Control Method:** -- **Emission Limit:** 81 ton/12 month rolling period

No add-on controls were seen in the review of other similar BACT determinations. Additionally, the EPA determined in 40 CFR Part 60, Subpart IIII that controls were not necessary for emergency engines with a displacement less than 30 liters per cylinder.

All of the emergency engines listed in the RBLC have BACT specified as compliance with the 40 CFR 60 Subpart IIII limits. None of the emergency engines have any post-combustion controls. NIPSCO is proposing compliance with the 40 CFR 60 Subpart IIII limits.

NIPSCO proposes an emission limit of 163.6 lb/MMBtu of fuel burned established for GHGs emissions from each emergency generator, on a CO2e basis, with compliance to be demonstrated using the procedures of 40 CFR § 98.33.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the emergency generator shall be as follows:

(1) The CO_2e emissions from each emergency generator (EDGCC1 and EDGCC2) shall be controlled through the use of good combustion practices including the installation of an equipment design standard and the compliance of the 40 CFR Part 60 Subpart IIII.

(2) The CO_2e emissions from each emergency generator (EDGCC1 and EDGCC2) shall not exceed 163.6 lb/MMBtu (GWPs per July 29, 2025).

BACT Analysis – Emergency Fire Pumps

Emission Unit Description

Two (2) 244 kW diesel-fired certified emergency fire pumps, identified as FPCC1 and FPCC2, approved in 2026 for construction, each with a maximum rated capacity of 327 hp, using no control, and to stacks SFPCC1 and SFPCC2.

[Under 40 CFR 60, Subpart IIII, these units are affected facilities]
[Under 40 CFR 63, Subpart ZZZZ, these units are affected sources]

VOC BACT Analysis – Diesel Emergency Fire Pumps

In ultra-low sulfur diesel (ULSD) emergency fire pump, VOC emissions are a result of incomplete combustion of carbon contained within the fuel. Properly designed and operated engines typically

emit low levels of VOC. High levels of VOC emissions could result from poor design or sub-optimal firing conditions.

Step 1: Identify All Potentially Available Control Technologies

Using RBLC search and permit review results, potentially applicable VOC control technologies for ICE were identified. These technologies include:

(1) Nonselective Catalytic Reduction
(2) Diesel Oxidation Catalyst
(3) Diesel Particulate Filters
(4) Lean NOx Catalyst
(5) Good Combustion Practices
(6) Usage Limitation

Step 2: Eliminate Technically Infeasible Options

Nonselective Catalytic Reduction

Nonselective Catalytic Reduction (NSCR) involves placing a catalyst in the exhaust stream of the engine and can simultaneously reduce NOx, CO, and VOCs. The reaction requires that the oxygen levels be kept low and that the engine be operated at fuel-rich air-to-fuel ratios. Under this condition, in the presence of the catalyst, NOx is reduced by the CO, resulting in nitrogen and CO_2. CO is oxidized to CO_2 and hydrocarbons are oxidized to CO_2 and water vapor. The catalyst used is generally a mixture of platinum and rhodium, with optimal catalyst operating temperatures between 800 and 1,200°F. CO can be reduced by 90-99% under rich-burn conditions.

The application of NSCR requires fuel-rich engine operation and is therefore limited to rich-burn engines (gasoline). Diesel engines tend to operate under lean-burn conditions. Therefore, NSCR is not considered to be technically feasible for the emergency fire pump.

All other control technologies are considered technically feasible.

Diesel Oxidation Catalyst

Diesel oxidation catalysts usually consist of a stainless steel canister that contains a honeycomb structure onto which catalytic metals such as platinum or palladium are coated. The diesel oxidation catalyst can reduce particulate, VOC and CO emissions by oxidizing them at an adequate exhaust temperature to become CO2 and water. VOC emissions can be reduced by 60-99%.

Diesel Particulate Filters

Diesel particulate filters consist of a filter in the exhaust stream designed to collect a significant fraction of the particulate emissions while allowing the exhaust gases to pass through. After a pre-established pressure drop is reached, the buildup of particulate is often incinerated through the use of heat provided by a variety of sources such as fueled burners, electric heaters, engine intake and throttling. The filter is then clean and regenerated for further use. Catalytic coatings on diesel particulate filters can also reduce CO and VOC emissions. VOCs can be reduced by 6080%.

Lean NOx Catalyst

NOx catalysts use a porous material made of zeolite with a precious metal or base metal catalyst. NOx emissions are controlled by injecting a small amount of diesel fuel or other hydrocarbon

reductant into the exhaust upstream of the catalyst, which reduces NOx to N2. The zeolites provide sites to attract the hydrocarbons to facilitate the NOx reduction reactions. Lean NOx Catalysts are also capable of reducing VOC emissions around 60%.

Good Combustion Practices

Good combustion practices are implemented in the design of the engine. Typical design features include electronic fuel-to-air ratio and timing controllers, pre-chamber ignition, intercoolers, and lean burn fuel mix. Good combustion practices are standard on new engines.

Usage Limitation

Restrictions on the amount of fuel or hours of operation can assist in limiting all emissions.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the technical feasibility analysis above, the remaining control technologies may be ranked as follows for controlling VOC emissions from the fire pump:

Diesel Oxidation Catalyst	60-99% VOC Reduction
Diesel Particulate Filter	60-80% VOC Reduction
Lean NOx Catalyst	60% VOC Reduction
Good Combustion Practices	Reduction Varies

To be considered technically feasible, a control technology must either be successfully demonstrated on a unit or, if not demonstrated, then be "available and applicable". A technology is considered "available" if it can be obtained by the applicant through commercial channels. An available technology is considered "applicable" if it can reasonably be installed and operated on the unit in question.

The feasibility of each of the potentially applicable control options identified is evaluated below:

(1) Based on this information reviewed for this BACT determination, diesel oxidation catalyst has been applied in diesel engine applications where engines are operated primarily at high capacity for extended periods of time for industrial and power generation purposes, such as “demand response” or “peak shaving” programs with revenue incentives, in large installations such as data centers, or in non-attainment areas. diesel oxidation catalyst effectiveness is limited in applications requiring quick startups and short operating durations, such as the required routine readiness testing and maintenance, because the practice is to minimize the length of these periods. Therefore, the application of diesel oxidation catalyst technology can be considered to be not technically feasible due to the sporadic nature of the emergency engines and is not considered further in this analysis.

(2) Based on the information reviewed for this BACT determination, diesel particulate filters are not considered technically feasible because engines that are operating intermittently for testing and maintenance purposes are unlikely to achieve and sustain the necessary exhaust temperatures to achieve consistent reductions. The filters will clog, reduce engine power, and may cause a malfunction.

Step 4: Evaluate Top Control Alternatives

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Proposed: NIPSCO - Schahfer Generating Station	073-49556-00008 (Pending)	N/A	Emergency Fire Pump (327 hp)	**Control Method:** Use of equipment design standards; Comply with 40 CFR 60, Subpart IIII **Emission Limit 1:** 6.4 g/kW-hr (4.8 g/hp-hr)
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	Emergency Fire Pump (282 hp)	**Control Method:** Good combustion practices Use of low sulfur fuel **Emission Limit 1:** 0.15 g/hp-hr **Emission Limit 2:** 0.090 lb/hr
Duke Energy Indiana, LLC - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	Emergency Fire Pump (300 hp)	**Control Method:** Engine certified to meet emission standards with 40 CFR 60, Subpart IIII **Emission Limit:** 4.00 g/kW-hr (equivalent to 3.0 g/hp-hr)
Shin tech Plaquemine Plant 4	PSD-LA-857 (12/16/2024)	LA-0403	Emergency Fire Pump (200 hp)	**Control Method:** Compliance with 40 CFR 60 Subpart IIII **Emission Limit 1:** 0.33 lb/hr **Emission Limit 2:** 4.00 g/kW-hr
Two Rivers Lumber- Alexander City	306-0018 (07/02/2024)	AL-0336	Emergency Fire Pump (321 hp)	**Control Method:** -- **Emission Limit 1:** 500.0 hours per year
Lansing Board of Water and Light- Delta Energy Park	71-24 (06/27/2024)	MI-0459	Emergency Fire Pump (500 hp)	**Control Method:** Good combustion practices **Emission Limit 1:** 4.00 g/kW-hr
Cronus Chemicals, LLC	19110020 (12/21/2023)	IL-0134	Emergency Fire Pump (369 hp)	**Control Method:** Compliance with 40 CFR 60 Subpart IIII **Emission Limit 1:** 4.00 g/kW-hr, 3-hrs average (NMHC + NOx) **Emission Limit 2:** 100.0 hrs/yr operational limit
Koch Methanol (KME) Facility	PSD-LA-851 (12/20/2023)	LA-0401	Emergency Fire Pump (422 hp)	**Control Method:** Compliance with 40 CFR 60 Subpart IIII **Emission Limit 1:** 1.47 lb/hr
			Emergency Fire Pump (237 hp)	**Control Method:** Compliance with 40 CFR 60 Subpart IIII **Emission Limit 1:** 0.61 lb/hr

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Destrehan Oil Processing Facility	PSD-LA-855 (12/13/2023)	LA-0402	Emergency Fire Pump (200 hp)	**Control Method:** Compliance with 40 CFR 60 Subpart IIII **Emission Limit 1:** 0.14 lb/hr hourly maximum **Emission Limit 2:** 0.010 ton/yr annual maximum
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Emergency Fire Pump (282 hp)	**Control Method:** Good combustion practices Combusting clean fuels **Emission Limit 1:** 1.10 g/hp-hr **Emission Limit 2:** 500.0 hours per year
Norfolk Crush, LLC	CP22-017 (11/21/2022)	NE-0064	Emergency Fire Pump (510 hp)	**Control Method:** Compliance with 40 CFR 60 Subpart IIII **Emission Limit 1:** 0.62 g/hp-hr
Kronospan, LLC	301-0079 (09/21/2022)	AL-0337	Emergency Fire Pump (460 hp)	**Control Method:** -- **Emission Limit 1:** 0.79 lb/hr
Intel Ohio Site	P0132323 (09/20/2022)	OH-0387	Emergency Fire Pump (275 hp)	**Control Method:** Good combustion practices Compliance with 40 CFR 60 Subpart IIII **Emission Limit 1:** 0.70 lb/hr **Emission Limit 1:** 0.20 ton/12 month rolling period
Alaska Gasline Development Corporation	AQ1539CPT01 (07/07/2022)	AK-0088	Emergency Fire Pump (300 hp)	**Control Method:** Oxidation Catalyst; Limited Operation; 40 CFR 60 Subpart IIII **Emission Limit 1:** 0.22 g/hp-hr **Emission Limit 2:** 500 hrs/yr
Marshall Energy Center, LLC	167-17B (06/23/2022)	MI-0451	(North Plant): Emergency Fire Pump (300 hp)	**Control Method:** Good combustion practices **Emission Limit:** 0.75 lb/hr
Marshall Energy Center, LLC	168-17B (06/23/2022)	MI-0452	(South Plant): Emergency Fire Pump (300 hp)	**Control Method:** Good Combustion Practices **Emission Limit:** 0.75 lb/hr
Magnolia Power LLC	PSD-LA-839 (06/03/2022)	LA-0391	Emergency Fire Pump (355 hp)	**Control Method:** Compliance with 40 CFR 60 Subpart IIII, Good combustion practices, Use of ultra-low sulfur diesel fuel. **Emission Limit:** 3.0 g/hp-hr

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Mountain State Clean Energy, LLC	R14-0038 (01/05/2022)	WV-0033	Emergency Fire Pump (240 hp)	**Control Method:** Good Combustion Practices w/ OxCat. Applicant did not justify why an oxcat is infeasible for an emergency engine **Emission Limit 1:** 1.59 lb/hr **Emission Limit 2:** 4.0 g/kW-h
Nemadji Trail Energy Center	18-MMC-168 (09/01/2020)	WI-0300	Emergency Fire Pump (282 hp)	**Control Method:** Operation limited to 500 hours/year Operate and maintain according to the manufacturer's recommendations. **Emission Limit:** 1.1 g/hp-hr
FG LA LLC	PSD-LA-812 (01/06/2020)	LA-0364	Emergency Fire Pump (550 hp)	**Control Method:** Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.
Chickahominy Power LLC	52610-1 (06/24/2019)	VA-0332	Emergency Fire Pump (500 hp)	**Control Method:** Good combustion practices, High efficiency design, Use of ultra-low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw. **Emission Limit:** 0.11 g/hp-hr
Venture Global Calcasieu Pass, LLC	PDS-LA-805 (09/21/2018)	LA-0331	Emergency Fire Pump (634 kW)	**Control Method:** Good combustion and operating practices. **Emission Limit:** 0.44 g/hp-hr
DTE Electric Company	19-18 (07/16/2018)	MI-0435	Emergency Fire Pump (399 hp)	**Control Method:** State of the art combustion design **Emission Limit:** 0.13 lb/hr
Marshall Energy Center LLC	167-17 AND 168-17 (06/29/2018)	MI-0433	(South Plant): Emergency Fire Pump (300 hp)	**Control Method:** Good combustion practices **Emission Limit:** 0.75 lb/hr
			(North Plant): Emergency Fire Pump (300 hp)	**Control Method:** Good combustion practices **Emission Limit:** 0.75 lb/hr
Novi Energy	52588 (04/26/2018)	VA-0328	Emergency Fire Pump (315 hp)	**Control Method:** Good combustion practices, Use of ultra-low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Harrison Power	P0122266 (04/19/2018)	OH-0377	Emergency Fire Pump (320 hp)	**Control Method:** Good combustion practices (ULSD), Compliance with 40 CFR Part 60, Subpart IIII **Emission Limit 1:** 2.12 lb/hr **Emission Limit 2:** 0.11 ton/yr
Guernsey Power Station LLC	P0122594 (10/23/2017)	OH-0374	Emergency Fire Pump (410 hp)	**Control Method:** Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturer's operating manual. **Emission Limit 1:** 2.7 lb/hr **Emission Limit 2:** 0.14 ton/yr
Oregon Energy Center	P0121049 (09/27/2017)	OH-0372	Emergency Fire Pump (300 hp)	**Control Method:** State-of-the-art combustion design **Emission Limit 1:** 0.24 lb/hr **Emission Limit 2:** 0.06 ton/12 months rolling period
Trumbull Energy Center	P0122331 (09/07/2017)	OH-0370	Emergency Fire Pump (300 hp)	**Control Method:** State-of-the-art combustion design **Emission Limit 1:** 0.24 lb/hr **Emission Limit 2:** 0.06 ton/12 months rolling period
Indeck Niles, LLC	75-16 (01/04/2017)	MI-0423	Emergency Fire Pump (260 hp)	**Control Method:** Good combustion practices **Emission Limit:** 0.64 lb/hr
Holland Board of Public Works	107-13C (12/05/2016)	MI-0424	Emergency Fire Pump (500 hp)	**Control Method:** Good combustion practices **Emission Limit:** 0.47 lb/hr
South Field Energy LLC	P0119495 (09/23/2016)	OH-0367	Emergency Fire Pump (311 hp)	**Control Method:** State-of-the-art combustion design **Emission Limit 1:** 0.25 lb/hr **Emission Limit 2:** 0.06 ton/12 months rolling period
Entergy Louisiana, LLC	PSD-LA-804 (08/31/2016)	LA-0313	Emergency Fire Pump (282 hp)	**Control Method:** Good combustion practices **Emission Limit 1:** 1.87 lb/hr (hourly maximum) **Emission Limit 2:** 0.47 ton/yr
Stonegate Power, LLC	19149/PCP150001 (07/19/2016)	NJ-0085	Emergency Fire Pump (100 hp)	**Control Method:** Use of ultra-low sulfur diesel (ULSD) oil as clean burning fuel and limited hours of operation **Emission Limit:** 0.117 lb/hr

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Virginia Electric and Power Company	52525 (06/17/2016)	VA-0325	Emergency Fire Pump (376 hp)	**Control Method:** Good Combustion Practices/Maintenance **Emission Limit:** 3.0 g/hp-hr
Lackawanna Energy Center, LLC	35-00069A (12/23/2015)	PA-0309	Emergency Fire Pump (15 gal/hr)	**Control Method:** -- **Emission Limit 1:** 0.12 g/hp-hr **Emission Limit 2:** 0.002 ton/12 months rolling period

No add-on controls were seen in the review of other similar BACT determinations. Additionally, the EPA determined in 40 CFR Part 60, Subpart IIII that controls were not necessary for emergency engines with a displacement less than 30 liters per cylinder.

All of the emergency fire pump engines listed in the RBLC have BACT specified as compliance with the 40 CFR 60 Subpart IIII limits. None of the emergency engines have any post-combustion controls. NIPSCO is proposing compliance with the 40 CFR 60 Subpart IIII limits.

The emergency fire pump engines to be installed at the NIPSCO facility will be certified by the equipment manufacturer to meet the applicable emission standards for nonroad, compression-ignition engines, as codified in 40 CFR Part 60 Subpart IIII and at 40 CFR Part 1039.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the fire pump shall be as follows:

(a) VOC emissions from each emergency fire pump (FPGCC1 and FPGCC2) shall be controlled good combustion practices including the installation of an equipment design standard and compliance with the requirements of 40 CFR 60, Subpart IIII.

(b) NMHC + NOx emissions from each emergency fire pump engine (FPGCC1 and FPGCC2) shall not exceed 6.4 g/ kW-hr.

GHG BACT Analysis – Diesel Emergency Fire Pumps

Step 1: Identify Potential Control Technologies

The available GHG emission control strategies for emergency generator and fire pump engine that were analyzed as part of this BACT analysis include:

(1) Carbon Capture and Storage (CCS)
(2) Selection of Fuel Efficient Engine
(3) Fuel Selection
(4) Good Combustion, Operating, and Maintenance Practices

Step 2: Eliminate Technically Infeasible Options

Carbon Capture and Storage (CCS)

Carbon Capture and Storage (CCS) involves separation and capture of CO2 from the combustion exhaust gases using physical or chemical adsorption, pressurization of the captured CO2,

transportation of the captured CO2 via pipeline, and injection and long-term geologic storage of the captured CO2. Carbon Capture and Storage (CCS) technology, specifically post-combustion CO2 capture technology, is not commercially available as it has not yet been successfully implemented on a large-scale basis such as a natural gas simple cycle power plant.

According to the Carbon Capture and Storage (CCS) task force report, CO2 capture technology is being operated at a small scale at several coal-fired power plants and there are plans to implement this technology on a larger scale at several coal-fired power plants in the coming years. However, Carbon Capture and Storage (CCS) technology, specifically post-combustion CO2 capture technology, is not commercially available and has not yet been successfully implemented on a large-scale basis.

For large projects, off-site CO2 storage generally relies upon a third-party CO2 pipeline system in order to transport the CO2 to a repository. Pipelines are the most common and theoretically feasible method for transporting large quantities of CO2. Specialized designs may be required for CO2 pipelines, particularly if supercritical CO2 is being transported. Transport of CO2 by pipeline is a demonstrated technology. Constructing such a pipeline for dedicated use by a single facility often will make a project economically infeasible. However, such an option may be effective if both adequate storage capacities exist in close proximity to the source, and reasonable transportation prices can be arranged with the pipeline operator.

Carbon capture and storage (CCS) is not considered an available control option for emergency equipment that operates on an intermittent basis and must be immediately available during plant emergencies without the constraint of starting up the CCS process. Therefore, CCS is not technically feasible for the emergency fire pump. Therefore, it has been eliminated from further consideration in the remaining steps of the analysis.

All other control technologies are considered feasible.

Efficient Engine Design

NIPSCO is proposing to install emergency fire pumps that are designed for optimal combustion efficiency.

Fuel Selection

The only technically feasible fuel for the fire pumps is diesel fuel. While natural gas-fired fire pumps may provide lower GHG emissions per unit of power output, natural gas is not considered a technically feasible fuel for the fire pump and emergency generator since it will need to be used in the event of fire, when natural gas supplies may be interrupted.

Good Combustion, Operating, and Maintenance Practices

The source will install an engine meeting the latest efficiency and pollutant performance standards specified in NSPS Part 60 Subpart IIII and NESHAP Part 63 Subpart ZZZZ . Good combustion and operating practices are a potential control option for maintaining the combustion efficiency of the emergency equipment. Good combustion practices include proper maintenance and tune-up of the fire pumps per the manufacturer’s specifications.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

NIPSCO will select fire pumps with high fuel combustion efficiency and will implement good combustion, operating, and maintenance practices to minimize GHG emissions.

Step 4: Evaluate Top Control Alternatives

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Proposed: NIPSCO - Schahfer Generating Station	073-49556-00008 (Pending)	N/A	Emergency Fire Pump (327 hp)	**Control Method:** Use of equipment design standards and comply with 40 CFR 60, Subpart IIII **Emission Limit 1:** 163.6 lb/MMBtu
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	Emergency Fire Pump (282 hp)	**Control Method:** Good engineering design, Fuel efficient design, Limited operating hours **Emission Limit 1:** 1,115,606 ton/12 month rolling period from the entire source
Duke Energy Indiana, LLC - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	Emergency Fire Pump (300 hp)	**Control Method:** Use of fuel-efficient unit **Emission Limit 1:** --
Lansing Board of Water and Light-Delta Energy Park	71-24 (06/27/2024)	MI-0459	Emergency Fire Pump (500 hp)	**Control Method:** Good combustion practices Use of current energy efficiency measures **Emission Limit 1:** 27.00 ton/12 month rolling period
Cronus Chemicals, LLC	19110020 (12/21/2023)	IL-0134	Emergency Fire Pump (369 hp)	**Control Method:** Compliance with 40 CFR 60 Subpart IIII **Emission Limit 1:** 25.0 ton/yr **Emission Limit 2:** 100.0 hr/yr operational limit
Destrehan Oil Processing Facility	PSD-LA-855 (12/13/2023)	LA-0402	Emergency Fire Pump (200 hp)	**Control Method:** Good combustion practices **Emission Limit 1:** 12.00 ton/yr annual maximum BACT shall include monitoring all parameters recommended by the manufacturer (e.g., flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature). Parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emission unit

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Shell Chemical LP Geismar Plant	PSD-LA-647(M-9) (12/12/2023)	LA-0394	Emergency Fire Pump (200 hp)	**Control Method:** Good combustion practices Compliance with 40 CFR 60 Subpart IIII **Emission Limit 1:** 12.0 ton/yr annual maximum
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Emergency Fire Pump (282 hp)	**Control Method:** Selection of the most efficient reciprocating internal combustion engine and minimizing the hours of operation limits greenhouse gas emissions. EPA Tier 3 certified reciprocating internal combustion engine and - limiting its hours of operation to 500 hours per each 12 consecutive calendar months. - Part of ensuring efficient engine operation is properly maintaining the engine and the combustion of clean fuels. In this case, clean fuel is determined to be ultra-low sulfur diesel fuel (less than 15 ppm sulfur content) **Emission Limit 1:** 500.0 hours per year
Maple Creek Energy LLC	T153-45909-00056 (06/19/2023)	IN-0365	Emergency Fire Pump (420 hp)	**Control Method:** Good engineering design and fuel efficient design **Emission Limit:** 123 ton/yr
Lincoln Land Energy Center (A/K/A Emberclear)	18040008 (07/29/2022)	IL-0133	Emergency Fire Pump (320 hp)	**Control Method:** -- **Emission Limit:** 92 ton/yr
Alaska Gasline Development Corporation	AQ1539CPT01 (07/07/2022)	AK-0088	Emergency Fire Pump (300 hp)	**Control Method:** Good Combustion Practices Limited Operation **Emission Limit 1:** 163.6 lb/MMBtu (3 hours) **Emission Limit 2:** 500 hrs/yr
Marshall Energy Center, LLC	167-17B (06/23/2022)	MI-0451	(North Plant): Emergency Fire Pump (300 hp)	**Control Method:** Good combustion practices **Emission Limit 1:** 85.6 ton/12 month rolling period
Marshall Energy Center, LLC	168-17B (06/23/2022)	MI-0452	(South Plant): Emergency Fire Pump (300 hp)	**Control Method:** Good combustion practices **Emission Limit:** 85.6 ton/12 month rolling period

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Nemadji Trail Energy Center	18-MMC-168 (09/01/2020)	WI-0300	Emergency Fire Pump (282 hp)	**Control Method:** Be certified by manufacturer to EPA's criteria for Tier 3 reciprocating internal combustion engines and to the 40 CFR 60, Subpart IIII emission limitations, operation limited to 500 hours/year, and operate and maintain according to the manufacturer's recommendations.
FG LA LLC	PSD-LA-812 (01/06/2020)	LA-0364	Emergency Fire Pump (550 hp)	**Control Method:** Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.
Magnolia Power LLC	PSD-LA-839 (06/03/2022)	LA-0391	Emergency Fire Pump (355 hp)	**Control Method:** Compliance with 40 CFR 60 Subpart IIII Good combustion practices, Use of ultra-low sulfur diesel fuel. **Emission Limit 1:** 74.21 kg/MMBtu (=163.6 lb/MMBtu)
Chickahominy Power LLC	52610-1 (06/24/2019)	VA-0332	Emergency Fire Pump (500 hp)	**Control Method:** Good combustion practices, High efficiency design, Use of ultra-low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw. **Emission Limit 1:** 106 ton/12 month rolling period
Indeck Niles, LLC	75-16B (11/26/2019)	MI-0445	Emergency Fire Pump (260 hp)	**Control Method:** Good combustion practices **Emission Limit:** 13.58 ton/12 month rolling period
Jackson Generation, LLC	17040013 (12/31/2018)	IL-0130	Emergency Fire Pump (420 hp)	**Control Method:** -- **Emission Limit 1:** 241 ton/12 month rolling period
Venture Global Calcasieu Pass, LLC	PDS-LA-805 (09/21/2018)	LA-0331	Emergency Fire Pump (634 kW)	**Control Method:** Good combustion practices Good operation and maintenance practices. **Emission Limit:** 44 ton/yr
DTE Electric Company	19-18 (07/16/2018)	MI-0435	Emergency Fire Pump (399 hp)	**Control Method:** Energy efficient design **Emission Limit 1:** 86 ton/12 month rolling period

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Marshall Energy Center LLC	167-17 AND 168-17 (06/29/2018)	MI-0433	(South Plant): Emergency Fire Pump (300 hp)	**Control Method:** Good combustion practices **Emission Limit:** 85.6 ton/12 month rolling period
			(North Plant): Emergency Fire Pump (300 hp)	**Control Method:** Good combustion practices **Emission Limit:** 85.6 ton/12 month rolling period
Novi Energy	52588 (04/26/2018)	VA-0328	Emergency Fire Pump (315 hp)	**Control Method:** Good combustion practices Use of ultra-low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw. **Emission Limit:** 1040 ton/12 month rolling period
Harrison Power	P0122266 (04/19/2018)	OH-0377	Emergency Fire Pump (320 hp)	**Control Method:** Efficient design and proper maintenance and operation **Emission Limit:** 18.67 ton/12 month rolling period
Guernsey Power Station LLC	P0122594 (10/23/2017)	OH-0374	Emergency Fire Pump (410 hp)	**Control Method:** Good operating practices (proper maintenance and operation) **Emission Limit:** 29.0 ton/12 month rolling period
Oregon Energy Center	P0121049 (09/27/2017)	OH-0372	Emergency Fire Pump (300 hp)	**Control Method:** State-of-the-art combustion design **Emission Limit:** 87.0 ton/12 month rolling period
Trumbull Energy Center	P0122331 (09/07/2017)	OH-0370	Emergency Fire Pump (300 hp)	**Control Method:** Efficient design **Emission Limit:** 87.0 ton/12 month rolling period
Indeck Niles, LLC	75-16 (01/04/2017)	MI-0423	Emergency Fire Pump (260 hp)	**Control Method:** Good combustion practices **Emission Limit:** 13.58 ton/12 month rolling period
Holland Board of Public Works	107-13C (12/05/2016)	MI-0424	Emergency Fire Pump (165 hp)	**Control Method:** Good Combustion Practices **Emission Limit:** 55.6 ton/12 month rolling period
South Field Energy LLC	P0119495 (09/23/2016)	OH-0367	Emergency Fire Pump (311 hp)	**Control Method:** Efficient design **Emission Limit:** 90.0 ton/12 month rolling period
Entergy Louisiana, LLC	PSD-LA-804 (08/31/2016)	LA-0313	Emergency Fire Pump (282 hp)	**Control Method:** Good combustion practices **Emission Limit:** 527.40 g/bhp-hr
Virginia Electric and Power Company	52525 (06/17/2016)	VA-0325	Emergency Fire Pump (376 hp)	**Control Method:** Good combustion practices and maintenance **Emission Limit:** 104.0 ton/12 month rolling period

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Lackawanna Energy Center, LLC	35-00069A (12/23/2015)	PA-0309	Emergency Fire Pump (315 hp)	**Control Method:** -- **Emission Limit:** 9.0 ton/12 month rolling period

No add-on controls were seen in the review of other similar BACT determinations. Additionally, the EPA determined in 40 CFR Part 60, Subpart IIII that controls were not necessary for emergency fire pump engines with a displacement less than 30 liters per cylinder.

All of the emergency fire pump engines listed in the RBLC have BACT specified as compliance with the 40 CFR 60 Subpart IIII limits. None of the emergency fire pump engines have any post-combustion controls. NIPSCO is proposing compliance with the 40 CFR 60 Subpart IIII limits.

NIPSCO proposes an emission limit of 163.6 lb/MMBtu of fuel burned established for GHGs emissions from each emergency fire pump engine, on a CO2e basis, with compliance to be demonstrated using the procedures of 40 CFR § 98.33.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the emergency generator shall be as follows:

(1) The CO_2e emissions from each emergency fire pump (FPGCC1 and FPGCC2) shall be controlled through the use of good combustion practices including the installation of an equipment design standard and the compliance of the 40 CFR Part 60 Subpart IIII.

(2) The CO_2e emissions from each emergency fire pump (FPCC1 and FPCC2) shall not exceed 163.6 lb/MMBtu (GWPs per July 29, 2025).

BACT Analysis – Dew Point Heater

Emission Unit Description

One (1) natural gas-fired dew point heater, identified as DPH1, approved in 2026 for construction, with a maximum rated capacity of 28 MMBtu per hour, using no control, and exhausting to stack SDPH1.

[Under 40 CFR 60, Subpart Dc, this is an affected facility]

VOC BACT Analysis – Dew Point Heater

VOC are emitted from natural gas-fired dew point heater because of incomplete combustion of gaseous fuel.

Step 1: Identify All Potentially Available Control Technologies

The available control options for reducing VOC emissions from small natural-gas-fired combustion units as provided in the RBLC database are as follows:

(1) Use of Pipeline Quality Natural Gas
(2) Good Combustion Practices

Step 2: Eliminate Technically Infeasible Options

The use of pipeline natural gas and good combustion practices are technically feasible and will be considered in the next step of this analysis.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The use of pipeline natural gas and good combustion practices can both be implemented simultaneously eliminating the need for ranking these options for small natural gas-fired combustion units.

Step 4: Evaluate Top Control Alternatives

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Proposed: NIPSCO - Schahfer Generating Station	073-49556-00008 (Pending)	N/A	Dew Point Heater (28 MMBtu/hr)	**Control Method:** Good Combustion Practices Use of natural gas as fuel **Emission Limit 1:** 5.5 lb/MMcf (= 0.005 lb/MMBtu)
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	Dew Point Heater (20 MMBtu/hr)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 0.025 lb/MMBtu **Emission Limit 2:** 0.50 lb/hr 3-test average
Duke Energy Indiana, LLC	165-47430-00001 (02/14/2025)	IN-0382	Fuel Gas Heaters (10.0 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** 0.01 lb/MMBtu (3-hr avg)
Entergy Texas, Inc. Orange County Advanced Power Station	166032 PSDTX1598 GHGPSDTX210 (03/13/2023)	TX-0939	Water Bath Heater (16.8 MMBtu/hr)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 0.005 lb/MMBtu
Nemadji Trail Energy Center	18-MMC-168 (09/01/2020)	WI-0300	Natural Gas Heater (10 MMBtu/hr)	**Control Method:** Only combust pipeline quality natural gas and operate and maintain heater according to the manufacturer's recommendations **Emission Limit 1:** 0.005 lb/MMBtu
Indeck Niles, LLC	75-16B (11/26/2019)	MI-0445	Two (2) Dew Point Heater (27 MMBtu/hr, total)	**Control Method:** Good combustion practices **Emission Limit 1:** 0.07 lb/hr (hourly; per each fuel heater)
Thomas Township Energy, LLC	210-18 (08/21/2019)	MI-0442	FG Pre-heat (7.0 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** 0.025 lb/MMBtu, hourly

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Chickahominy Power LLC	52610-1 (06/24/2019)	VA-0332	Three (3) Fuel Gas Heaters (103.0 MMcf/yr)	**Control Method:** good combustion practices, operator training, and proper emissions unit design, construction and maintenance **Emission Limit 1:** 0.005 lb/MMBtu **Emission Limit 2:** 0.30 ton/12-month rolling period
Michigan State University	139-18 (05/22/2019)	MI-0440	Dew Point Heater (25 MMBtu/hr)	**Control Method:** Good combustion practices or efficient combustion **Emission Limit 1:** 0.005 lb/MMBtu
DTE Electric Company – Belle River Combined Cycle Power Plant	168-18 (07/16/2018)	MI-0435	Fuel Heater (20.8 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** 0.17 lb/hr
			Fuel Heater (3.8 MMBtu/hr)	**Control Method:** Good combustion practices **Emission Limit 1:** 0.03 lb/hr
Guernsey Power Stations LLC	P0122594 (10/23/2017)	OH-0374	Fuel Gas Heater (15.0 MMBtu/hr)	**Control Method:** Combustion control **Emission Limit 1:** 0.075 lb/hr **Emission Limit 2:** 0.33 ton/12-mo rolling period **Standard Emission Limit:** 0.005 lb/MMBtu
Indeck Niles, LLC	75-16 (01/04/2017)	MI-0423	Two fuel pre-heaters (EUFUELHTR1 and EUFUELHTR2) (27 MMBtu/hr, total)	**Control Method:** Good combustion practice **Emission Limit 1:** 0.15 lb/hr (per fuel heater)
Holland Board of Public Works - East 5th Street	107-13C (12/05/2016)	MI-0424	Fuel pre-heater (3.70 MMBtu/hr)	**Control Method:** Good combustion practices **VOC Emission Limit:** 0.03 lb/hr

Based on this evaluation, NIPSCO is proposing use of natural gas fuel and good combustion practices as BACT for VOC emissions from the proposed dew point heater. In addition, NIPSCO proposes the VOC emission factor of 5.5 lb/MMcf (equivalent to 0.005 lb/MMBtu) as VOC BACT limit, which is from AP-42 Chapter 1.4, July 1998, for natural gas combustion. The proposed VOC BACT limits are consistent with other facilities operating similar equipments identified on RBLC data.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the dew point heater DPH1 shall be as follows:

(a) VOC emissions from the natural gas-fired dew point heater DPH1 shall not exceed 5.5 lb/MMcf.

(b) VOC emissions from the natural gas fired dew point heater DPH1 shall be controlled by good combustion practices.

(c) The Permittee shall only combust natural gas fuel in the dew point heater DPH1.

GHG BACT Analysis – Dew Point Heater

GHGs are emitted from the natural gas-fired dew point heater from combustion of fuel. Therefore, the most direct approach for reducing these emissions is to maximize combustion efficiency in the heater.

Step 1: Identify All Potentially Available Control Technologies

The available control options for reducing GHG emissions from small natural gas-fired combustion units as provided in the RBLC database are as follows:

(1) Use of Pipeline Quality Natural Gas
(2) Good Combustion Practices

Step 2: Eliminate Technically Infeasible Options

The use of pipeline natural gas and good combustion practices are technically feasible and will be considered in the next step of this analysis.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness (PM)

The use of pipeline natural gas and good combustion practices can both be implemented simultaneously eliminating the need for ranking these options for small natural gas-fired combustion units.

Step 4: Evaluate the Most Effective Controls and Document the Results (PM)

The table below shows the proposed PM BACT determination for the emergency fire water pump, as well as other BACT determinations found in the USEPA RACT/BACT/LAER Clearinghouse (RBLC) and/or other permits.

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Proposed: NIPSCO - Schahfer Generating Station	073-49556-00008 (Pending)	N/A	Dew Point Heater (28 MMBtu/hr)	**Control Method:** Good Combustion Practices Use of natural gas as fuel **Emission Limit 1:** 119,438 lb/MMcf (=117.0 lb/MMBtu)
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	Dew Point Heater (20 MMBtu/hr)	**Control Method:** Good Combustion Practices and low sulfur fuels **Emission Limit 1:** 1,115,606 ton/12 month rolling period
Duke Energy Indiana, LLC	165-47430-00001 (02/14/2025)	IN-0382	Fuel Gas Heater (10.0 MMBtu/hr)	**Control Method:** Good combustion practices Use of pipeline quality natural gas **Emission Limit 1:** 10258.0 ton/12 month rolling period
Wabash Valley Resources, LLC	167-45208-00091 (01/11/2024)	IN-0371	Dew Point Heater (1.44 MMBtu/hr)	**Control Method:** Good Combustion Practices **Emission Limit 1:** 117.0 lb/MMBtu

Entergy Texas, Inc. Orange County Advanced Power Station	166032 PSDTX1598 GHGPSDTX210 (03/13/2023)	TX-0939	Water Bath Heater (16.8 MMBtu/hr)	**Control Method:** Good Combustion Practices **Emission Limit 1:** --
Nemadji Trail Energy Center	18-MMC-168 (09/01/2020)	WI-0300	Natural Gas Heater (10 MMBtu/hr)	**Control Method:** Only combust pipeline quality natural gas and operate and maintain heater according to the manufacturer's recommendations **Emission Limit 1:** --
Indeck Niles, LLC	75-16B (11/26/2019)	MI-0445	Two (2) Dew Point Heater (27 MMBtu/hr, total)	**Control Method:** Good combustion practices **Emission Limit:** 13,848 ton/12 month rolling period for combined units
Thomas Township Energy, LLC	210-18 (08/21/2019)	MI-0442	FG Pre-heat (7.0 MMBtu/hr)	**Control Method:** Energy Efficiency **Emission Limit 1:** 3,590.0 ton/12 month rolling period
Chickahominy Power LLC	52610-1 (06/24/2019)	VA-0332	Three (3) Fuel Gas Heaters (103.0 MMcf/yr)	**Control Method:** Use of natural gas and high efficiency design and operation **Emission Limit 1:** 6,261 ton/yr
Michigan State University	139-18 (05/22/2019)	MI-0440	Dew Point Heater (25 MMBtu/hr)	**Control Method:** Utilize low-carbon fuels and implement energy efficiency measures and preventative maintenance pursuant to manufacturer recommendations **Emission Limit 1:** 12,822 ton/12 month rolling period
DTE Electric Company – Belle River Combined Cycle Power Plant	168-18 (07/16/2018)	MI-0435	Fuel Heater 1 (20.8 MMBtu/hr) Fuel Heater 2 (3.8 MMBtu/hr)	**Control Method:** Natural gas fuel **Emission Limit 1:** 6,310 ton/12 month rolling period total (for both heaters)
Guernsey Power Stations LLC	P0122594 (10/23/2017)	OH-0374	Fuel Gas Heater (15.0 MMBtu/hr)	**Control Method:** Natural gas Low-emitting fuel **Emission Limit 2:** 7,695 ton/12-mo rolling period
Indeck Niles, LLC	75-16 (01/04/2017)	MI-0423	Two fuel pre-heaters (EUFUELHTR1 and EUFUELHTR2) (27 MMBtu/hr, total)	**Control Method:** Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas) **Emission Limit 1:** 13,848 ton/12-mo rolling period, combined (for both heaters)
Holland Board of Public Works - East 5th Street	107-13C (12/05/2016)	MI-0424	Fuel pre-heater (3.70 MMBtu/hr)	**Control Method:** Good combustion practices **VOC Emission Limit:** 1,934 ton/12-mo rolling period

Based on this evaluation, NIPSCO is proposing use of natural gas fuel and good combustion practices as BACT for GHGs emissions from the proposed dew point heater. In addition, NIPSCO proposes the CO2e emission factor of 119,438 lb/mmcf (equivalent to 117.0 lb/MMBtu) as GHG BACT limit, which from 40 CFR Part 98, July 2025 version, for natural gas combustion. The

proposed VOC BACT limits are consistent with other facilities operating similar equipments identified on RBLC data.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the turbine fuel heaters shall be as follows:

(1) CO_2e emissions from the natural gas fired dew point heater DPH1 shall not exceed 119,438 lb/MMcf (GWPs per July 29, 2025).

(2) GHG emissions from the natural gas fired dew point heater DPH1 shall be controlled by good combustion practices.

(3) The Permittee shall only combust natural gas fuel in the dew point heater DPH1.

BACT Analysis – Lube Oil Demister Vents

Emission Unit Description

Six (6) lube oil demister vents, identified as LOV21A, LOV21B, LOV22A, LOV22B, LOV21S, and LOV22S, approved in 2026 for construction, each with a vent flow rate of 500 cfm.

VOC BACT Analysis – Lube Oil Demister Vents

The combustion turbines and steam turbine generators (STGs) include lubricating oil tanks. The vents located on the side of the tanks are equipped with demisters and emit small amount of VOC. Using RBLC search and permit review results, potentially applicable VOC control technologies were identified based on the principles of the control technology and engineering experience for lube oil demister vent.

Step 1: Identify All Potentially Available Control Technologies

The available control options for reducing VOC emissions from lube oil vents as provided in the RBLC database are as follows:

(1) Use of demister
(2) Good engineering design

Step 2: Eliminate Technically Infeasible Options

The air flow from the lube oil vent and oil mist loading are sufficiently low to prohibit the use of any add-on controls to control VOC emissions from the lube oil vents. Therefore, the use of a catalytic oxidizer or regenerative thermal oxidizer are not technically feasible options.

Additionally, flares have not been utilized or demonstrated as a control device for VOCs from this type of high-volume process stream. In addition, a flare would have no additional control versus the catalytic oxidizer or thermal oxidizer. Therefore, the use of a flare is not a technically feasible option.

Both the use of demister and good engineering design are technically feasible.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Both the use of demister and good engineering design are technically feasible. Since both options could be applied simultaneously, ranking step is unnecessary.

Step 4: Evaluate Top Control Alternatives

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Proposed: NIPSCO - Schahfer Generating Station	073-49556-00008 (Pending)	N/A	Lube Oil Demister Vents	**Control Method:** Mist eliminator Good design and operating practices **Emission Limit 1:** --
Duke Energy Indiana, LLC	165-47430-00001 (02/14/2025)	IN-0382	Lube Oil Demister Vents	**Control Method:** Good Engineering design and operation practices **Emission Limit:** --
Jack County Generating Facility	PSDTX1640, GHGPSDTX240 (12/27/2024)	TX-0986	Lube Oil Vents	**Control Method:** Mist eliminator Good design and operating practices **Emission Limit 1:** --
Orange County Advanced Power Station	166032 PSDTX1598 GHGPSDTX210 (03/13/2023)	TX-0939	Lube Oil Demister Vents	**Control Method:** Mist eliminator **Emission Limit 1:** --
FG LA Complex	PSD-LA-812 (01/06/2020)	LA-0364	UT2 Cogeneration and Steam Turbine Lube Oil Vents	**Control Method 1:** -- **Emission Limit 1:** --

Based on this evaluation, NIPSCO is proposing the use of demister with the lube oil tank vents to reduce VOC emissions. In addition, good engineering design practices will be implemented to ensure minimal VOC emissions from this operation.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the lube oil demister vents shall be as follows:

(a) VOC emissions from each of the lube oil demister vents shall be controlled through the use of demisters and good engineering design and operating practices.

BACT Analysis – Circuit Breakers

Emission Unit Description

High Voltage Electric Switchgear Containing Sulfur Hexafluoride (SF6), identified as CCCT - Circuit Breakers, approved in 2026 for construction.

GHG BACT Analysis – Circuit Breakers

GHGs are emitted from the proposed SF6 insulated circuit breakers due to necessary maintenance and leaks.

Step 1: Identify All Potentially Available Control Technologies

The available control options for reducing GHGs emissions from the proposed SF6 insulated circuit breakers provided in the RBLC database are as follows:

(1) Alternative Technology
(2) Alternative dielectric materials

Step 2: Eliminate Technically Infeasible Options

Alternative Technology

The use of fully enclosed circuit breakers with leak detection (low pressure alarm) is state-of-the art for circuit breakers. A low-pressure alarm is installed on each breaker to alert operators of a loss of SF_6 gas. Operators will investigate the cause of any alarm and take corrective measures to stop the leak if one exists.

The use of alternative technology is a technically feasible option for the circuit breakers to be installed as part of this project.

Alternative Dielectric Material

There is no practical alternative to the use of SF_6 as the insulator and arc quenching substance in circuit breakers that would meet NIPSCO's needs. All non-SF_6 containing circuit breakers that are currently commercially available can only be used for applications with lower voltage needs than what NIPSCO's project requires. The unique performance qualities of SF_6 breakers are further supported by the report released by the U.S. EPA SF_6 Partnership, which states: "no clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties." Due to the size circuit breakers that the Project requires and the current technological constraint, the use of a breaker that doesn't contain SF_6 is judged as not available for this application at this time.

The use of Alternative Dielectric Material is not a technically feasible option for the circuit breakers to be installed as part of this project.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The most effective method for controlling SF_6 emissions is the use of totally enclosed and pressurized circuit breakers with a density alarm for leak detection.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Requirements
Proposed: NIPSCO - Schahfer Generating Station	073-49556-00008 (Pending)	N/A	Circuit Breakers	**Control Method:** Use fully enclosed pressurized SF6 circuit breakers outfitted with density alarms for leak detection **Emission Limit 1:** Maximum SF6 leak rate to not exceed 0.5% leak rate per 12-month rolling period
AES Indiana, LLC-Eagle Valley Generating Station	109-49087-00004 (10/07/2025)	IN-0400	Circuit Breakers	**Control Method:** Fully enclosed SF6 circuit breakers outfitted with low pressure alarms for leak detection **Emission Limit 1:** 192.40 ton/12-month rolling period Maximum leak not to exceed 0.5% per 12-month rolling period
Marquis Carbon Capture LLC	23110009 (06/23/2025)	IL-0137	Circuit Breakers	**Control Method:** Low-leak design, Insulating (or dielectric) material with a GWP of no greater than 292, LDAR **Emission Limit 1:** 0.020 ton/yr Leak rate not to exceed 0.5% per 12-month rolling period
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	Circuit Breakers	**Control Method:** totally enclosed and pressurized circuit breakers with a design leak rate of no more than 0.5% and a density alarm for leak detection **Emission Limit 1:** 73.60 ton/12 month rolling period **Emission Limit 2:** 1,115,606 tons of GHG per 12 month rolling period for total source wide
Duke Energy Indiana, LLC	165-47430-00001 (02/14/2024)	IN-0382	Circuit Breakers	**Control Method:** fully enclosed pressurized SF6 circuit breakers outfitted with density alarms for leak detection **SF6 Emission Limit:** 0.5% leak rate per 12-month rolling period
Lincoln Land Energy Center (A/K/A Emberclear)	18040008 (7/29/2022)	IL-0133	Circuit Breakers	**Control Method:** Leak Detection and Repair (LDAR) program, systematic operations tracking and procedures for quantification of GHG pursuant to 40 CFR 98 Subpart DD. **Emission Limit 1:** 0.5% leak rate, 12-mo rolling period **Emission Limit 2:** 12.0 lb/12-mo rolling period

Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Circuit Breakers	**Control Method:** Enclosed pressure design with a low pressure detection system **Emission Limit 1:** 0.5% leak rate, 12-mo rolling period **Emission Limit 2:** 85.0 ton/yr
Shady Hills Energy Center, LLC	1010524-003-AC (PSD-FL-444A) 6/7/2021	FL-0371	Circuit Breakers	**Control Method:** -- **Emission Limit 1:** 0.5% leak per year
Nemadji Trail Energy Center	18-MMC-168 (09/01/2020)	WI-0300	Circuit Breakers	**Control Method:** -- **Emission Limit 1:** 0.5% leak per year
WPL- Riverside Energy Center	19-POY-151 (8/20/2020)	WI-0299	Containing Circuit Breakers and Transformers	**Control Method:** -- **Emission Limit 1:** 0.5% leak rate, by weight annually
Chickahominy Power LLC	52610-1 (06/24/2019)	VA-0332	Circuit Breakers	**Control Method:** Enclosed-pressure design with low-pressure detection system (with alarm) **Emission Limit 1:** --
Jackson Generation, LLC	17040013 (12/31/2018)	IL-0130	Circuit Breakers	**Control Method:** -- **Emission Limit 1:** 0.5% leak rate calendar year avg **Emission Limit 2:** 10.0 lb/12-mo rolling period
St. Joseph Energy Center	141-39839-00579 (08/08/2018)	IN-0294	Circuit Breakers	**Control Method:** -- **Emission Limit 1:** 0.5% leak rate
CPV Three Rivers, LLC	16060032 (07/30/2018)	IL-0129	Circuit Breakers	**Control Method:** -- **Emission Limit 1:** 0.5% leak rate calendar year avg **Emission Limit 2:** 14.6 lb/12-mo rolling period
Shady Hills Energy Center, LLC	1010524-001-AC (07/27/2018)	FL-0367	Circuit Breakers	**Control Method:** -- **Emission Limit 1:** 0.5% leak per year
Novi Energy C4GT, LLC	52588 (04/26/2018)	VA-0328	Circuit Breakers	**Control Method:** Enclosed-pressure design with low-pressure detection system (with alarm). **Emission Limit 1:** 0.5% leak per year
Florida Power & Light - Dania Beach Energy Center	0110037-017-AC (12/04/2017)	FL-0363	Circuit breakers	**Control Method:** Certified leak rate < 0.5% per year **Emission Limit 1:** 0.5% leak per year

Southern Power Jackson County Generating Facility	GHGPSDTX118 (06/30/2017)	TX-0824	Circuit breakers	**Control Method:** Use of circuit breakers with totally enclosed insulation systems equipped with a low pressure alarm and low pressure lockout **Emission Limit 1:** 34.40 ton/yr
CPV Fairview, LLC	11-00536A (09/02/2016)	PA-0310	Circuit breakers	**Control Method:** State-of-the-art sealed enclosed-pressure circuit breakers with leak detection **Emission Limit 1:** 1500 PPM
Virginia Electric and Power Company Greensville Power Station	52525 (06/17/2016)	VA-0325	Three (3) Circuit breakers	**Control Method:** Enclosed pressure type breaker and leak detector **Emission Limit 1:** 19.00 ton/yr
			Eleven (11) Circuit breakers	**Control Method:** Enclosed pressure type breaker and leak detector **Emission Limit 1:** 1032.00 ton/yr
Florida Power & Light - Okeechobee Clean Energy Center	0930117-001-AC (03/09/2016)	FL-0356	Circuit breakers	**Control Method:** Must be equipped with leakage detection systems and alarms. **Emission Limit 1:** 0.50% leak rate per year
Lackawanna Energy Center - Jessup	35-00069A (12/23/2015)	PA-0309	Circuit breakers	**Control Method:** low pressure alarms and low pressure lockout system **Emission Limit 1:** 6.0 lb/12-month rolling period
Mattawoman Energy, LLC	PSC CASE. NO. 9330 11/13/2015	MD-0045	CIRCUIT BREAKERS	**Control Method:** -- **Emission Limit 1:** --

Based on this evaluation, NIPSCO is proposing the use of a fully enclosed pressurized SF6 circuit breakers outfitted with density alarms for leak detection and the circuit breakers shall be designed to have a maximum SF6 leak rate not to exceed 0.5% per twelve (12) consecutive month period.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the circuit breakers shall be as follows:

(a) The Permittee shall use a fully enclosed pressurized SF6 circuit breakers outfitted with density alarms for leak detection.

(b) The circuit breakers shall be designed to have a maximum SF6 leak rate not to exceed 0.5% per twelve (12) consecutive month period.

BACT Analysis – Natural Gas Piping Systems

Emission Unit Description

Natural gas piping components, identified as CCCT - Piping Systems, approved in 2026 for construction, including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections.

VOC and GHGs BACT Analysis – Natural Gas Piping Systems

Emissions of VOC and GHGs as CH_4 from natural gas piping components including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections occur due to natural gas leaks. Natural gas contains small amount of VOC.

Step 1: Identify All Potentially Available Control Technologies

The following technologies are available to control fugitive emissions from natural gas piping systems:

(1) Leakless technology components
(2) Leak detection and repair (LDAR) program
(3) Alternative monitoring using remote sensing technology
(4) Audio/visual/olfactory (AVO) monitoring program

Step 2: Eliminate Technically Infeasible Options

Leakless technology components

“Leakless” technologies such as bellows or seal valves can reduce fugitive natural gas emissions by eliminating valve gasket and flange leak paths. Other leak paths nevertheless do exist so that this technology does not eliminate fugitive emissions. Leakless technology components are used for highly toxic and hazardous materials but are not normally used in natural gas piping systems because of the high cost for these components and the difficulty in maintaining and repairing these components. For example, if a welded or threaded and seal welded bonnet joint valve fails, the failed component cannot be repaired without a unit shutdown, and the repair may result in additional maintenance related natural gas venting. Seal valves have other limitations which limit their use, including cycle life, pressure retention capability, and size limitations.

Because these components are not standard used in natural gas piping systems, the use of leakless valves is not considered a technically feasible control option for these natural gas piping systems.

Leak detection and repair (LDAR) program, Alternative monitoring using remote sensing technology, and Audio/visual/olfactory (AVO) monitoring program

Leak detection and repair (LDAR) programs, alternative monitoring using remote sensing technology, and audio/visual/olfactory (AVO) monitoring programs are technically feasible control options.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Leak detection and repair (LDAR) programs using instrument monitoring are effective for identifying leaking components and is an accepted practice for limiting VOC emissions from gas processing and chemical plants. Quarterly monitoring with an instrument and a leak definition of 500 ppm is considered to have a control efficiency of 97% for valves, flanges, and connectors. Remote sensing using infrared imaging is also effective in detecting leaks, especially for components in difficult to monitor areas and is considered to be equivalent to LDAR.

Audio/visual/olfactory (AVO) monitoring is also an effective monitoring method for odorous and low vapor pressure compounds such as natural gas, especially because the observations can be substantially more frequent than for LDAR. Pipeline natural gas is purposely odorized with mercaptan for safety. As a result, natural gas leaks have a discernible odor. Larger leaks can be detected by sound and sight, either directly or as a secondary indicator such as condensation around a leaking source due to the cooling effect of the expanding gas as it leaves the leaking component. Thus, observations for leaking valves or components can be made when plant personnel make routine walkdowns of the plant. As a result, AVO observation is an effective method for identifying and correcting leaks in natural gas systems, especially larger leaks that can result in increased emissions and potentially hazardous conditions. The Texas Commission on Environmental Quality (TCEQ) also assigns a 97% control effectiveness for AVO for odorous and low vapor pressure compounds such as natural gas.

Step 4: Evaluate Top Control Alternatives

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC/GHG Requirements
Proposed: NIPSCO - Schahfer Generating Station	073-49556-00008 (Pending)	N/A	Natural Gas Piping Systems	**Control Method:** Implementation of an Audio/Visual/Olfactory (AVO) program **Emission Limit 1:** --
Marquis Carbon Capture LLC	23110009 (06/23/2025)	IL-0137	Piping and Piping Equipment	**Control Method:** AVO on a daily basis **GHGs Emission Limit 1:** 135.66 ton/12 month rolling period
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	Natural gas piping	**Control Method:** Leak less components OR LDAR **GHGs Emission Limit 1:** 55.7 ton/twelve (12) month consecutive period **GHGs Emission Limit 2:** Source-wide 1,117,664 tons/12 month rolling period
Quail Run Carbon Capture Plant	173197, HAP83, PSDTX1622 (02/05/2024)	TX-0967	Equipment Fugitives	**Control Method:** voluntary 28M leak detection and repair (LDAR) program **VOC Emission Limit 1:** 9.38 ton/yr
Commonwealth LNG Facility	PSD-LA-841 (03/28/2023)	LA-0324	Fugitive Emissions	**Control Method:** Appropriate component selection, design, and installation Utilizing proper piping design Compliance with LAC 33:III.2111 LDAR **VOC Emission Limit 1:** --
Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	Natural Gas Piping and Piping Components	**Control Method:** Leak less components or LDAR **Emission Limit 1:** 1.53 ton/yr (not a BACT limit)

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC/GHG Requirements
Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Fugitives emissions from piping components	**Control Method:** Proper piping design and installation **GHG Emission Limit 1:** 104.0 ton/yr
El Paso Electric Company - Newman Power Station	N284, PSDTX1090M1, GHGPSDTX199 (08/27/2021)	TX-0908	Fugitives emissions	**Control Method:** Weekly AVO **VOC Emission Limit :** -- **GHG Emission Limit :** --
LBC Houston Bayport Terminal	123325 AND N206M2 (03/05/2021)	TX-0899	Fugitives emissions	**Control Method:** 28LAER program **VOC Emission Limit :** --
Chevron Phillips Chemical Company LP - Cedar Bayou Plant	123325 AND N206M2 (03/05/2021)	TX-0918	Fugitive Components	**Control Method:** 28LAER program **VOC Emission Limit :** --
Plains Marketing LP - Cushing Terminal	2015-1352-C(M-3)PSD (08/27/2019)	OK-0180	Fugitive Equipment Leaks	**Control Method:** Conduct and record AVO observations **VOC Emission Limit :** --
Chickahominy Power LLC	52610-1 (06/24/2019)	VA-0332	Equipment Leaks from Natural Gas Components	**Control Method:** Best management practices to prevent, detect and repair leaks of natural gas from the piping components **GHG Emission Limit :** --
Novi Energy C4GT, LLC	52588 (04/26/2018)	VA-0328	Equipment Leaks from Natural Gas Components	**Control Method:** Best management practices to prevent, detect and repair leaks of natural gas from the piping components **GHG Emission Limit :** --
BPV Gathering and Marketing Cushing Station	2016-1247-C PSD (07/19/2017)	OK-0176	Fugitive Equipment Leaks	**Control Method:** Conduct and record AVO observations **VOC Emission Limit :** Entire source: 217.24 ton/yr
Southern Power Jackson County Generating Facility	GHGPSDTX118 (06/30/2017)	TX-0824	Natural Gas Fugitives	**Control Method:** Weekly checks for leaks using AVO sensing for natural gas leaks **GHG Emission Limit :** 693.30 ton/yr
Virginia Electric and Power Company Greensville Power Station	52525 (06/17/2016)	VA-0325	Gas Piping Components - Fugitive Leaks	**Control Method:** AVO monitoring and leak repair **GHG Emission Limit :** --
LBC Houston Bayport Terminal	123325, N206 (02/05/2016)	TX-0783		**Control Method:** 28LAER program **VOC Emission Limit :** 500.0 PPMV
Mattawoman Energy Center	PSC CASE. NO. 9330 (11/13/2015)	MD-0045	Equipment Leaks	**Control Method:** AVO monitoring **VOC Emission Limit :** --

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC/GHG Requirements
				GHG Emission Limit : --

The use of audio/visual/olfactory (AVO) monitoring is an effective monitoring method for the control of fugitive VOC emissions from the natural gas piping systems. The proposed project will also utilize high quality components and materials of construction that are compatible with the service in which they are employed. This is the highest level of control available for the control of methane emissions from the piping systems.

NIPSCO proposes the use of audio/visual/olfactory (AVO) monitoring as BACT for the control of fugitive VOC and GHGs emissions from the natural gas piping systems.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the lube oil demister vents shall be as follows:

(a) The permittee shall implement an auditory/visual/olfactory (AVO) monitoring program for detecting leaks from the natural gas piping components installed as part of 2026 CCCT Project.

(b) AVO monitoring shall be performed in accordance with a written monitoring program.

BACT Analysis – Diesel Storage Tank

Emission Unit Description

One (1) diesel storage tank, identified as TKCC1, approved in 2026 for construction, with a maximum storage capacity of 5,000 gallons and maximum throughput of 130,000 gallons per year, using no control, and exhausting outdoors.

VOC BACT Analysis – Diesel Storage Tank

A 5,000-gallon diesel storage tank is proposed under the Project. This tank will result in breathing losses and working losses that will result in small amounts of VOC emissions. This section presents the required VOC BACT analysis for the diesel storage tank. There are no State, local or federal regulations applicable to VOC emissions from a small diesel storage tank. Therefore, there is no “BACT baseline” for this operation.

Step 1: Identify All Potentially Available Control Technologies

The following technologies are available to control VOC emissions from the diesel storage tanks:

(1) Catalytic oxidation
(2) Regenerative thermal oxidation
(3) Good equipment design and operating practices

Step 2: Eliminate Technically Infeasible Options

Catalytic oxidation

Catalytic oxidation is the process of oxidizing organic contaminants in a waste gas stream within a heated chamber containing a catalyst bed in the presence of oxygen for sufficient time to completely oxidize the organic contaminants to carbon dioxide and water. This technique is typically used to incinerate VOC stream with an inlet flow rate ranging from 700 – 50,000 scfm and inlet stream VOC concentration as low as 1 ppmw. VOC emissions and flow rate from the proposed diesel storage tank will be well below these levels. Therefore, catalytic oxidation is not technically feasible.

Regenerative thermal oxidation

A regenerative thermal oxidizer typically consists of a set of 2 or 3 packed ceramic beds that are used to recover heat from hot combustion gases that are generated during combustion of the VOC gas stream and auxiliary fuel, resulting in improved oxidizer efficiency and reduced auxiliary fuel usage. An "inlet" bed is used to pre-heat the untreated VOC gas stream, an "outlet" bed is used to recover heat from the treated gas stream, and one bed is in a purge cycle. The purge cycle is needed to prevent emission spikes each time the gas flow is redirected. This technique uses a high temperature combustion chamber to incinerate VOC stream by a combination of auxiliary fuel and waste gas compounds. Most units operated with an inlet flow rate ranging from 10,000 – 100,000 scfm and an inlet stream VOC concentration as low as 100 ppmw. VOC emissions and flow rate from the proposed diesel storage tank will be well below these levels. Therefore, RTO is not technically feasible.

Good equipment design and operating practices

Good equipment design and operating practices are technically feasible control options.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

No ranking is required as no controls are technically feasible for this operation. However, the use of good equipment design and operating practices for the proposed diesel storage tank are feasible practices for limiting VOC emissions.

Step 4: Evaluate Top Control Alternatives

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Proposed: NIPSCO - Schahfer Generating Station	073-49556-00008 (Pending)	N/A	Diesel Fuel Tank	**Control Method:** Implement good equipment design and operating practices **Emission Limit 1:** --
Corpus Christi Liquefaction Stage 3	PSDTX1496M1, GHGPSDTX157M1 (05/30/2025)	TX-0976	Diesel Tanks	**Control Method:** Capacity < 1000 gal, VP < 0.35 psia, White, Fixed Roof, Submerged Fill **Emission Limit 1:** --
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	ULSD Diesel Fuel Tanks	**Control Method:** Good operating practices, submerged fill, shell painted white **Emission Limit 1:** 0.34 ton/12 month rolling period

Quail Run Carbon Capture Plant	173197, HAP83, PSDTX1622 (02/05/2024)	TX-0967	Fixed Roof Storage Tanks	**Control Method:** Submerged fill and uninsulated exterior surfaces exposed to the sun are painted white. Send liquid to a covered vessel when draining the tank **Emission Limit 1:** --
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Diesel Fuel Tanks	**Control Method:** Use of fixed roof tanks; Performing submerged-filling or bottom loading; and these storage tanks may only store diesel fuel. **Emission Limit 1:** --
Entergy Texas, Inc. - Orange County Advanced Power Station	166032 PSDTX1598 GHGPSDTX210 (03/13/2023)	TX-0939	Storage Tanks	**Control Method:** Bottom fill, exterior surfaces are painted white, unpainted stainless steel, or unpainted aluminum **Emission Limit 1:** --
Teal Jones-Plain Dealing Saw Mill	PSD-LA-845 (10/31/2022)	LA-0399	Diesel Tanks	**Control Method:** Light color, fixed roofs, submerged fill/bottom loading, and good operating practice **Emission Limit 1:** --
Novelis Corporation - Guthrie	V-22-011 (07/25/2022)	KY-0116	Diesel Fuel Storage Tank	**Control Method:** Spill & overfill protection, Submerged fill pipes, & Good Work Practices (GWP) Plan **Emission Limit 1:** --
Alaska Gasline Development Corporation Liquefaction Plant	AQ1539CPT01 (07/07/2022)	AK-0088	Three (3) Diesel Storage Tanks	**Control Method:** Submerged fill **Emission Limit 1:** 0.010 ton/yr for the 3 tanks
Bill Greehey Refinery East Plant	2937, PSDTX1023M3 (03/29/2022)	TX-0936	Fixed Roof Storage Tanks	**Control Method:** submerged fill, painted white **Emission Limit 1:** --
Jupiter Brownsville, LLC - Centurion Brownsville	147681, PSDTX1522, GHGPSDTX172 (10/19/2021)	TX-0930	Fixed Roof Storage Tanks	**Control Method:** Painted white or unpainted aluminum, utilize submerged fill, and designed to be drain-dry **Emission Limit 1:** --
Nemadji Trail Energy Center	18-MMC-168 (09/01/2020)	WI-0300	Diesel Fuel Storage Tanks	**Control Method:** Use of fixed roof tanks, perform submerged-filling or bottom loading of each fixed roof storage tank; and storage tanks may only store diesel fuel **Emission Limit 1:** --
Alaska Gasline Development Corporation Gas Treatment Plant	AQ1524CPT01 (08/13/2020)	AK-0085	Nine (9) Diesel Fuel Storage Tanks	**Control Method:** Submerged Fill **Emission Limit 1:** 0.59 ton/yr for all tanks

Orange Polyethylene Plant	155952 PSDTX1556 GHGPSDTX192 (04/23/2020)	TX-0888	Fixed Roof Storage Tanks	**Control Method:** Submerge fill piping or bottom fill piping and painted white **Emission Limit 1:** --
Equistar Chemicals Channelview Complex	N266, PSDTX1542, GHGPSDTX183 (09/09/2019)	TX-0864	Fixed Roof Storage Tanks	**Control Method:** Painted white, submerged fill **Emission Limit 1:** --
Buckeye Texas Processing Corpus Christi Facility	109923, PSDTX1502, AND GHGPSDT (08/29/2019)	TX-0861	Fixed Roof Storage Tanks	**Control Method:** Painted white with submerged fill **Emission Limit 1:** --
Riverview Energy Corporation	T147-39554-00065 (06/11/2019)	IN-0318	Storage Tanks	**Control Method:** Tanks shall use a white shell. Tanks shall use submerged filling. Tanks shall use good maintenance practices **Emission Limit 1:** 0.0114 tons/12 month rolling period
Buckeye South Texas Gateway Terminal	151476, PSDTX1536, AND GHGPSDT (03/13/2019)	TX-0855	Fixed Roof Tanks	**Control Method:** Painted white and equipped with the submerged fill piping **Emission Limit 1:** --
SIO International Wisconsin, Inc. -Energy Plant	18-JJW-017 (04/24/2018)	WI-0284	Diesel Storage Tanks	**Control Method:** Use of submerged fill pipes for bottom loading and the utilization of white outer paint and pressure relief valves **Emission Limit 1:** --
Enbridge Energy Limited Partnership	17-DCF-091 (10/02/2017)	WI-0279	Diesel Fuel Tank Storage	**Control Method:** Good Operating Practices **Emission Limit 1:** --
Magellan Terminals Holdings, L.P - Pasadena Terminal	142261 AND N254 (07/14/2017)	TX-0825	Horizontal Fixed Roof Storage Tanks	**Control Method:** Painted white and submerged fill **Emission Limit 1:** 0.37 ton/yr
Donlin Gold Project	AQ0934CPT01 (06/30/2017)	AK-0084	Diesel Fuel Tanks	**Control Method:** Submerged Fill **Emission Limit 1:** 1.70 ton/yr for all tanks (EU126 through EU157)
ST. Joseph Energy Center	141-37912-00579 (06/22/2017)	IN-0273	Diesel Tank Storages	**Control Method:** Use of good design and operating practices. Each tank shall utilize a fixed roof **Emission Limit 1:** --
Baton Rouge Junction Facility	PSD-LA-741(M4) (12/15/2016)	LA-0276	Vertical Fixed Roof Tanks	**Control Method:** Submerged fill pipes and pressure/vacuum vents **Emission Limit 1:** --
Odessa Petrochemical Plant	16963, PSDTX1478, GHGPSDTX148 (11/22/2016)	TX-0813	Petroleum Liquid Storage Fixed Roof Tanks	**Control Method:** Submerged fill pipe, reflective or white exterior paint

				Emission Limit 1: 0.010 ton/yr
Fritz Winter North America, LP	V-16-022 R1 (10/24/2016)	KY-0109	Diesel Storage Tank	**Control Method:** Permanent submerged fill pipe, Work practice requirements **Emission Limit 1:** --
Houston Fuel Oil Terminal	5783, N57M1, O1093 (09/02/2016)	TX-0808	Storage Tank	**Control Method:** Insulated, submerged fill, painted white **Emission Limit 1:** 0.10 ton/yr
Phillips 66 Pipeline LLC - Beaumont Terminal	18295, PSDTX1466, GHGPSDTX139 (06/08/2016)	TX-0799	Storage Tanks - Fixed Roof	**Control Method:** Ese submerged fill and have white exterior surfaces or aluminum exterior surfaces **Emission Limit 1:** 72.50 ton/yr
Port of Beaumont Petroleum Transload Terminal	118901, GHGPSDTX108 AND PSDTX1 (11/06/2015)	TX-0772	Petroleum Liquids Storage Fixed Roof Tanks	**Control Method:** Use submerged fill and aluminum color **Emission Limit 1:** 0.010 ton/yr

Based on this evaluation, NIPSCO proposes to implement good equipment design and operating practices to limit and lower VOC emissions from the proposed diesel storage tank.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the lube oil demister vents shall be as follows:

(a) The permittee shall implement good equipment design and operating practices for the proposed diesel storage tank.

Appendix C
Air Quality Analysis

Source Description and Location

Source Name:	NIPSCO LLC– R.M. Schahfer Generating Station
Source Location:	2723 E 1500 N, Wheatfield, Indiana 46392
County:	Jasper
SIC Code:	4911 (Electricity Generation)
PSD/Significant Source Modification No.:	073-49556-00008
Modeling Reviewer:	Emma Foust

Proposed Project Overview

Northern Indiana Public Service Company LLC (NIPSCO) – R.M. Schahfer Generating Station (Schahfer) plans to modify its facility in Jasper County near Wheatfield, Indiana by installing four combined cycle combustion turbines and ancillary support equipment. The proposed combined cycle turbine project relies on shutdown emissions from Schahfer's coal-fired Units 15, 17 and 18 and their associated cooling towers. RTP Environmental Associates submitted a Prevention of Significant Deterioration (PSD) permit application to OAQ on September 5, 2025 and modeling analysis on November 6, 2025.

Modeling Analysis Summary

The proposed modification was determined to be a major PSD source and is therefore required to perform an air quality modeling analysis. Dispersion modeling is used in the permitting process to estimate the concentration of pollutants at specified ground-level receptors surrounding an emission source. Air quality models use mathematical equations and algorithms to simulate the processes that affect air pollutants as they disperse in the atmosphere. Based on inputs of meteorological data, building data, source information like emission rates and stack parameters, dispersion models are designed to characterize pollutants that are emitted directly into the atmosphere.

Modeling Results Overview

The following pollutants were examined for Schahfer to determine whether an air quality analysis is required based on their Significant Emission Rates (SER).

- Exceeded the SER with PTE in tons per year:
  - Volatile organic compounds (VOCs)
- Did not exceed the SER with PTE in tons per year:
  - Nitrogen oxides (NO_x)
  - Carbon monoxide (CO),
  - Sulfur dioxide (SO_2),
  - Particulate matter with an aerodynamic diameter of 10 micrometers and smaller (PM_{10})
  - Particulate matter with an aerodynamic diameter of 2.5 micrometers and smaller ($PM_{2.5}$).
  - Lead (Pb)
- Pre-construction monitoring is not required for VOCs.
- A single source secondary ozone analysis was performed and no significant impacts on 8-hour ozone were found from this proposed modification.
- A single source secondary $PM_{2.5}$ formation analysis was not performed.
- Additional Impact Analysis:
  - No adverse impact to economic growth, vegetation, soils, visibility, and endangered species is expected.
  - A HAP screening analysis was performed - and the screening results were compared with U.S. EPA recommended health based thresholds and cancer risk information.
- Hazardous Air Pollutant (HAPs) emissions did exceed the 10 tons/year single HAP and the 25 tons/year for an aggregate emission rate threshold. Therefore, a screening analysis was conducted for HAPs for the proposed project.

Section A – Applicability Determination/Assessment

The PSD requirements, as stated in 326 Indiana Administrative Code (IAC) 2-2, apply in attainment and unclassifiable areas and require an air quality impact analysis of each regulated pollutant emitted in significant amounts by a major stationary source or modification. SILs for each pollutant are defined in 326 IAC 2-2-1 and in the Code of Federal Regulations (CFR) 52.21(b)(23)(i). Jasper County is designated as attainment for all applicable NAAQS.

Pollutants and Emission Rates Analyzed

NO_2, CO, PM_{10}, $PM_{2.5}$, SO_2, and VOCs are the pollutants that will be emitted from Schahfer and are summarized in Table 1. VOCs exceeded the PSD significant emission rates (SER), as shown below in Table 1, therefore a regulatory air quality analysis was conducted for this pollutant. In addition, HAPs emissions did exceed the 10 tons/year for a single HAP and the 25 tons/year emission threshold for all HAPs so a non-regulatory screening analysis was conducted.

A netting analysis was conducted for these pollutants since previously permitted Units 15, 17, and 18 coal-fired boilers have been or will be shut down during this period. After netting of the contemporaneous increases and decreases for Schahfer, the resultant net emission increases do not exceed their respective SER for PM_{10}, $PM_{2.5}$, SO_2, CO and NO_x. Therefore, the proposed project is not subject to PSD review for these pollutants and no air quality analysis was conducted. A PSD air quality analysis is included for VOCs since this pollutant exceeded its respective SER, as shown in Table 1. Emission rates can be found in Table 4-2 of Schahfer's application.

TABLE 1
Significant Emission Rates (SER) for PSD Modeling Applicability

POLLUTANT	2026 CCCT Project Net Emissions Increases (t/yr)	SIGNIFICANT EMISSION RATE (t/yr)	PRELIMINARY AQ ANALYSIS REQUIRED
NO_x	39.77	40	NO
CO	< 0	100	NO
$PM_{2.5}$	9.84	10	NO
PM_{10}	14.18	15	NO
SO_2	< 0	40	NO
VOCs[1]	296.11	40	YES
Single HAP (Hexane)	14.01	10	HAPs screening
Total HAPs	37.95	25	HAPs screening

[1] VOCs are only analyzed for secondary formation.

Section B – Air Dispersion Modeling Inputs and Description

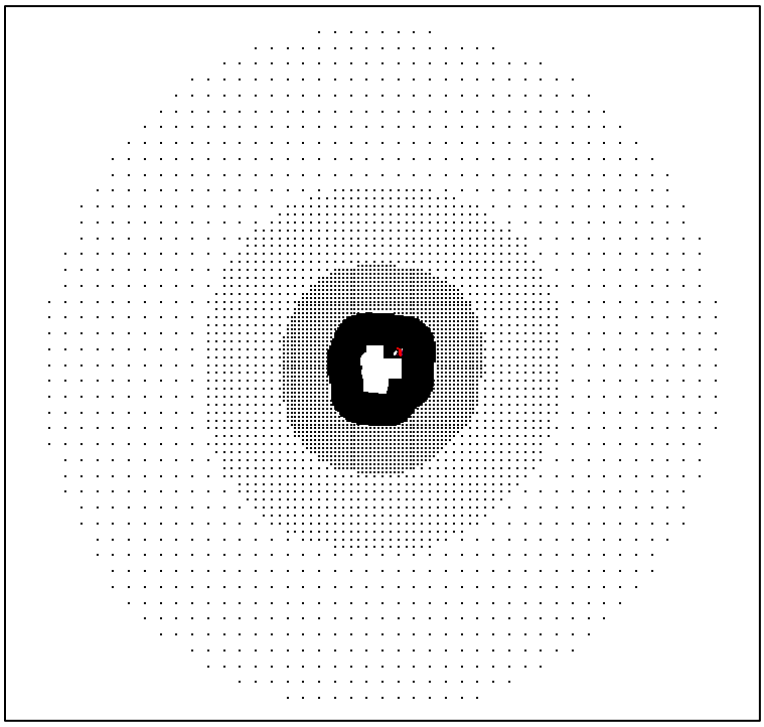
Air Dispersion Model

OAQ used the most recent version of American Meteorological Society Environmental Protection Agency Regulatory Model (AERMOD) (Version 24142) for its review of the air quality analysis to determine maximum off-property impacts for each HAP. AERMOD is U.S. EPA's preferred near field dispersion model. OAQ utilized all regulatory default options in the U.S. EPA approved model, as listed in the 40 CFR Part 51, Appendix W "Revision to the Guideline on Air Quality Models., dated January 17, 2017" otherwise known as Appendix W.

Receptor Grid

The main purpose of the receptor grid is twofold. It is to define the applicant's significant impact area (SIA) for each pollutant and to capture the maximum concentrations of the applicant and possible inventory sources that have significant impact in the applicant's SIA. To do this OAQ does recommend a standardized grid but other grid configurations are acceptable provided they define the applicant's SIA and capture the maximum estimated impacts. Modeling was performed as part of the HAPs screening procedure using a 20 km grid. The receptor grid spacing is outlined below:

- Grid containing 50 meter receptor spacing along the property boundary,
- Grid containing 100 meter receptor spacing from the property boundary to 4 kilometers,
- Grid containing 250 meters receptor spacing from 4 to 7 kilometers,
- Grid containing 500 meters receptor spacing from 7 to 12 kilometers
- Grid containing 1000 meters receptor spacing from 12 to 20 kilometers



Treatment of Terrain

Receptor terrain elevation inputs were interpolated from National Elevation Dataset (NED) data obtained from the U.S. Geological Survey (USGS). NED terrain data was preprocessed using AERMAP. Selection of rural or urban dispersion coefficients is dependent on the results of the Auer land-use analysis which examines a 3-km radius around Schahfer. Based on that analysis, the area surrounding Schahfer is considered rural and the terrain is predominantly flat / industrial, surrounded by a mixture of undeveloped land, residences, and farmland. Appendix A showed the land use determination for the area surrounding the Schahfer facility

Building Downwash and Stack Height/Good Engineering Practice (GEP) Considerations

Stacks should comply with Good Engineering Practice (GEP) requirements, defined in Section 123 of the Clean Air Act (CAA) and established in 326 IAC 1-7-4. If stacks are lower than GEP, excessive ambient concentrations due to aerodynamic downwash may occur. Building Profile Input Program (BPIP) calculations are applied when stacks are less than GEP for downwash effects. Dispersion modeling credit for stacks taller than 65 meters or 213 feet is limited to GEP for the purpose of establishing emission limitations. The GEP stack height takes into account the distance and dimensions of nearby structures, which would affect the downwind wake of the stack. The downwind wake is considered to extend five times the lesser of the structure's height or width. Since the new stack heights for Schahfer are below GEP stack height, the effect of aerodynamic downwash will be accounted for in the air quality analysis for the proposed project.

Meteorological Data

Meteorological data used for the air quality analysis for Schahfer consisted of surface meteorological data from the South Bend Airport National Weather Service (NWS) Automated Surface Observing System (ASOS) station merged with the upper air data from the Lincoln, IL NWS station from 2020 through 2024.

Additionally, the 1-minute ASOS wind speed and wind direction data were processed with the AERMINUTE preprocessor version 15272. OAQ preprocessed all meteorological data with regulatory defaults into an AERMOD ready format using U.S. EPA's meteorological preprocessor, AERMET Version 24142.

Section C – Initial Regulatory Modeling Analysis

Significant Impact Level (SIL) Analysis

VOCs are only analyzed for secondary formation, therefore a SIL analysis was not performed.

Pre-Construction Monitoring Analysis

VOCs are only analyzed for secondary formation, therefore a pre-construction monitoring analysis was not performed.

Section D – Refined Regulatory Modeling Analysis

NAAQS Modeling Analysis

VOCs are only analyzed for secondary formation of ozone, therefore a NAAQS analysis was not performed.

PSD Increment Analysis

There is no PSD increment for VOC or ozone.

Single Source Secondary $PM_{2.5}$ and Ozone Analysis

Secondary $PM_{2.5}$ and ozone (O_3) are air pollutants formed through chemical reactions of precursor emissions of NOx, SO_2 and VOCs in the atmosphere. Assessing the formation of O_3 and secondary $PM_{2.5}$ is useful for interpreting overall air quality impacts of changes in precursor pollutant emissions from new PSD major sources or PSD major modifications to that area. This assessment is only done if secondary precursor pollutants exceed their respective SERs.

To address this issue, the U.S. EPA released an updated version of a document titled *Clarification on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program* (MERPS Guidance). This guidance provides states, local agencies, and tribes with modeled emission rates of hypothetical facilities that emit precursor pollutants to ozone and $PM_{2.5}$ that a source could use to determine, through this Tier 1 demonstration, whether its emissions have made a significant contribution to secondary pollution formation

Technical Background for MERPS Assessment

The first tier (or Tier 1) involves use of appropriate and technically credible relationships between emissions and ambient impacts developed from existing modeling studies deemed sufficient for evaluating a project source's impacts. The Tier 1 analysis can be used to determine if a facility's proposed emission increases will result in secondary impacts that are above the appropriate SILs. If the applicant fails the SIL analysis, the cumulative analysis is performed to see if the applicant's previous results with monitored background are above the NAAQS.

If a facility cannot meet the SIL or cumulative analysis using the Tier 1 approach, a more refined

dispersion or photochemical modeling analysis (Tier 2) may be required. The second tier (or Tier 2) involves more sophisticated case-specific application of chemical transport modeling (e.g., with a Eulerian grid or Lagrangian model).

Within the MERPS Guidance, there were four hypothetical facilities modeled by U.S. EPA in Indiana, located in Boone, Dubois, Grant, and Porter Counties. The Boone, Dubois and Grant Counties facilities are representative of rural regions, while the Porter County facility is representative of an industrialized region.

A technical justification must be provided that the applicant's source characteristics are adequately represented by the selected hypothetical source for the Tier 1 analysis. Items that are examined are stack heights, emission rates, terrain, urban and rural classification, local meteorology, and distance from the applicant.

Tier 1 Analysis

TABLE 7
Source Emissions (tons/year) for Schahfer for MERPS Applicability

PRECURSOR POLLUTANT	2026 CCCT Project Net Emissions Increases (t/yr)	Significant Emission Rate (SER) (t/yr)	MERPS Analysis Required	Primary Modeling Required
NO_X	39.77	40	No	No
SO_2	0	40	No	No
VOC	296.11	40	Yes	No
$PM_{2.5}$	9.84	10	No	No

Hypothetical Source Selection

A hypothetical source was selected for this analysis which is representative of Schahfer. The hypothetical source is in Porter County, the closest modeled source in terms of distance. Other items that were examined for representativeness were stack heights, emission rates, terrain, urban and rural classification, and local meteorology. Table 8 shows the values used for the hypothetical source chosen.

TABLE 8
Hypothetical Source Parameters for Schahfer

PRECURSOR POLLUTANT	COUNTY	Averaging Time	Emissions	Stack Height	Concentration
VOC	Porter	8-hour Ozone	500	10	0.39
NO_x	Porter	8-hour Ozone	500	10	1.18

SIL Analysis

Schahfer was above the SER for VOC for a MERPS analysis as shown in Table 7.

The following equation is used for the SIL analysis:
For 8-hour ozone, the following equation should be used if NOx or VOCs ≥ 40 tpy:

O_3 SIL < Project Air Quality Impact = [Project NOx emissions × (NOx Modeled Conc. Hypothetical Source ÷ NOx Modeled Emission Rate from Hypothetical Source)] + [Project VOC emissions × (VOC Modeled Conc. Hypothetical Source ÷ VOC Modeled Emission Rate from Hypothetical Source)]

*O_3 SIL < Project Air Quality Impact = 39.77 * (1.1760737896 / 500) + 296.11* (0.3897503018 / 500) = 0.32436283*

= *0.324* < **1 ppb (Ozone SIL)**

Based on the SIL analysis, Schahfer's proposed emissions are not expected to have an impact above the SIL for the 8-hour ozone.

Cumulative Analysis

Since the SIL assessment did not exceed the threshold, a cumulative analysis was not conducted.

Background Selection

Background monitoring was selected which represented the area where the source was located.

TABLE 9
Background Concentrations

POLLUTANT	TIME AVERAGING PERIOD	MONITOR ID	MONITOR LOCATION	MONITOR COUNTY	2022-2024 CONCENTRATION
O_3	8-hour	18-127-0026	Valparaiso	Porter	68 ppb

The Valparaiso, Porter County O_3 monitor was chosen as the background monitor since it represents the appropriate airshed in that area. The 8-hour ozone design value concentration for 2022-2024 at the Valparaiso monitor is 68 parts per billion (ppb), below the 8-hour Ozone National Ambient Air Quality Standard of 70 ppb. Therefore, Jasper County is designated as attainment for 8-hour ozone.

Summary of Secondary Pollutant Analysis

In summary, based on the Tier 1 MERPS analysis, Schahfer's VOC impacts are not expected to exceed the SIL for 8-hour Ozone. Since Schahfer shows no violation of the Tier 1 analysis, a Tier 2 analysis is not required.

Section E - Qualitative Additional Impacts Analysis

All PSD permit applicants must prepare an additional impact analysis for each pollutant subject to regulation under the CAA. This analysis assesses the impacts on growth, soils and vegetation, endangered species, and visibility caused by any increase in emissions of any regulated pollutant from the source. IDEM conducted its review of the analysis which is summarized below.

Economic Growth

The purpose of the growth analysis is to quantify project associated growth and estimate the air quality impacts from this growth either quantitatively or qualitatively. It is estimated that no additional jobs will be

created as a result of this project and growth impacts related to the NAAQS and PSD increments are expected to be negligible. The proposed project should not hinder other industrial growth in the area.

Soils and Vegetation

The land surrounding the proposed modification is primarily agricultural and the maximum modeled concentrations from Schahfer are well below the primary and secondary health-based threshold limits necessary to have adverse impacts on the surrounding vegetation. Soil types within Jasper County include sandy and loamy Lacustrine deposits and Eolian sand. Crops in Jasper County and nearby areas consist mainly of grains, oilseeds, dry beans, and dry peas. Livestock in Jasper County consists mainly of cattle and is not expected to be adversely impacted by the facility. Trees in the area are mostly hardwoods and impacts from the proposed project to the trees are expected to be negligible.

Federal and State Endangered Species

On the federal level, the endangered species list is managed under the Endangered Species Act. Federal endangered species are listed by the U.S. Fish and Wildlife Service for the State of Indiana. This species list includes 4 birds, 3 mammals, 11 mussels, 2 reptiles, 3 insects and 6 plants. Of these species, two mammals are found within Jasper County. These species are not located around industrial settings.

Visibility

A visibility impairment analysis is required to demonstrate that emissions from a project do not cause a significant impairment of visibility. This proposed modification will not result in an increase in any of the applicable visibility impairment pollutants, so a visibility analysis was not necessary.

Hazardous Air Pollutant Screening

OAQ currently requests data concerning the emission of 187 HAPs regulated by the U.S.EPA under the CAA; the original list included 189 pollutants. Since 1990, U.S. EPA has modified the list through rulemaking so the current list includes 187 hazardous air pollutants. These chemicals are listed in the 1990 Clean Air Act Amendments (CAAA) as either carcinogenic or otherwise considered toxic and may be used by industries in the State of Indiana. These substances are listed as air toxic compounds on the State of Indiana, Department of Environmental Management, Office of Air Quality's construction permit application Form GSD-08. In addition, the air toxics provisions of the CAA required U.S. EPA to develop and enforce regulations to protect the public from exposure to airborne contaminants that are known to be hazardous to human health. In accordance with Section 112 of the CAA, U.S. EPA established National Emission Standards for Hazardous Air Pollutants (NESHAP) in order to ensure emissions levels of HAPs that are already being achieved by the best-controlled and lowest-emitting sources in an industry. These health-based emission limits are enforceable to protect public health or welfare. Refer to Section E of the permit for any applicable NESHAPs requirements on emissions units for Schahfer.

Any air quality dispersion modeling conducted for HAPs is not explicitly required by State of Indiana statute. The HAPs modeling is conducted for informational purposes only and should not be construed as an exhaustive analysis for health risk for a given geographical area. In accordance with Section 112(b) of the CAA, the state evaluates HAPs emissions greater than 10 tons per year of a single HAP or 25 tons per year of total HAPs. This evaluation consists of air dispersion screening and comparison of the results with applicable non-cancer chronic reference concentrations and cancer unit risk factors. No federal or state ambient air quality standards have been developed for HAPs.

For the 2026 CCCT Project, Schahfer’s largest emissions from a single HAP (Hexane) totaled 14.01 tons per year, and the total of all HAPs emissions are estimated at 37.95 tons per year. The emissions are shown in Table 13 below. The project will result in potential emissions greater than 10 tons per year of a single HAP and/or 25 tons per year of total HAPs. Therefore, a HAPs screening analysis was conducted

for the proposed project.

HAPs Screening Assumptions

This HAPs screening analysis used conservative health protective assumptions that overestimate the actual risk associated with emissions from Schahfer. Assumptions included: 1) a 70 year continuous (8760 hours a year) exposure time at a modeled high concentration receptor location, 2) all carcinogens cause the same type of cancer, 3) all non-carcinogens have additive health effects, 4) maximum permit allowable emissions from the facility, and 5) use of conservatively derived dose-response information. The screening analysis cannot accurately predict whether there will be observed health problems surrounding Schahfer; rather it identified possible avenues of risk through the estimated concentrations.

Hazard Index Screening for Non-Cancerous HAPs

Non-cancer health effects are determined using the Reference Concentration (RfC). The RfC is an estimate of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a person's lifetime. Dividing the pollutant's estimated annual concentration by the RfC will determine the pollutant's Hazard Quotient (HQ). All of the HAPs' Hazard Quotients added together determine the overall Hazard Index (HI). A Hazard Index above 1 does not represent a level where adverse health effects will be observed but indicates that the potential for a risk of health effects could exist. A Hazard Index below 1 is not considered to be a health concern.

Unit Risk Factor Screening

The Unit Risk Factor (URF) is the upper-bound excess lifetime cancer risk estimates that would result from continuous inhalation exposure to a pollutant over a 70-year lifetime at that modeled high concentration receptor location. Multiplying the estimated annual concentration by the URF for each HAP will produce a conservative cancer risk estimate, usually expressed as the number of additional cancer cases in a given number of people, e.g. one in a million. For screening purposes at Schahfer, the cancer estimates for each pollutant are considered to be additive when deriving the cumulative maximum individual cancer risk.

The U.S. EPA will generally presume that if the risk to an individual is no higher than 100 in a million, that risk level is considered acceptable and U.S. EPA would then consider other health and risk factors to complete an overall judgment on acceptability. Lifetime cancer risks that fall between the one in a million and 100 in a million range may generate discussion between IDEM and the source to address the impacts, taking into account the assumptions used to determine the estimate. While there are no federal standard or law by which to prompt a source to reduce their emissions of HAPs below these risk levels, any risks over 100 in a million could result in additional review by IDEM and U.S.EPA.

For comparison purposes, the American Cancer Society (ACS)[1] reports that the annual average incidence of cancer in Indiana between 2012 and 2016 was 4,571 per a million (age adjusted to the 2000 US standard population); these statistics are for all cancers based on the current ACS 2020 estimates. The probability for the general public to be exposed to the maximum modeled concentration of HAPs from Schahfer for 24 hours a day, seven days a week, 52 weeks a year for 70 years is considered very minimal.

Screening Results for Schahfer

[1] https://cancerstatisticscenter.cancer.org/#!/state/Indiana

Table 13 shows each HAP emission, annual screened concentration for each HAP, the non-cancerous and cancerous risks, the individual HAP and cumulative hazard quotients and the Hazard Index.

- Results from the Hazard Index for the project's HAPs screened concentrations totaled 2.53E-02, which does not exceed 1.
- Each individual HAP's screened concentration and their individual URF cancer risk were estimated. The cumulative cancer risk estimate from all HAPs is 5.01E-06 additional cancer cases with continuous exposure for 70 years.

TABLE 10
Hazardous Air Pollutant Screening Results

COMPOUND	EMISSIONS (t/yr)	SCREENED ANNUAL IMPACTS (µg / m^3)	Non-Cancer Chronic RfC (µg / m^3)	HAZARD QUOTIENT	CANCER URF (µg / m^3)$^{-1}$	CANCER RISK
Acetaldehyde	1.923354	0.00372	9 [a]	4.13E-04	2.20E-06 [a]	8.18E-09
Acrolein	0.307747	0.0006	0.35 [c]	1.71E-03	-	-
Benzene	0.597283	0.00291	30 [a]	9.67E-05	7.80E-06 [a]	2.26E-08
1,3-Butadiene	4.47E-05	0.00006	2.00	3.00E-05	3.0E-05	1.8E-09
Cadmium compounds	1.22E-03	0.00026	0.02[c]	1.30E-02	1.80E-03 [a]	4.68E-07
Chromium (VI) compounds	1.55E-03	0.00034	0.1 [a]	3.40E-03	1.20E-02 [a]	4.08E-06
Dichlorobenzene	1.33E-03	0.00029	200 [f]	1.45E-06	6.9E-06 [f]	1.99E-09
Ethylbenzene	1.537744	0.00289	1000.00 [a]	2.89E-06	2.5E-06 [c]	7.23E-09
Formaldehyde	10.0742	0.02299	9.8 [b]	2.35E-03	1.30E-05 [a]	2.99E-07
Hexane	14.0078	0.43624	700 [a]	6.23E-04	-	-
Lead compounds	5.54E-04	0.00012	0.15[c]	8.00E-04	1.20E-05 [c]	1.44E-09
Manganese compounds	4.21E-04	0.00009	0.30[b]	3.00E-04	-	-
Napthalene	0.06247	0.00012	3.00[a]	4.00E-05	3.4E-05 [c]	4.08E-09
Nickel	0.00233	0.0005	0.2 [b]	2.50E-03	2.40E-04 [a]	1.2E-07
Toluene	6.25462	0.01236	5000 [a]	2.47E-06	-	-

Xylene	3.07808	0.00611	100.00[a]	6.11E-05	-	-
TOTALS (HAZARD INDEX)				**2.53E-02**		**5.01E-06**

a IRIS - U.S. EPA's Integrated Risk Information System

b ATSDR - Agency for Toxic Substances and Disease Registry

c CAL – California

d **HEAST - Health Effects Assessment Summary Tables - EPA**

e **Region 9**

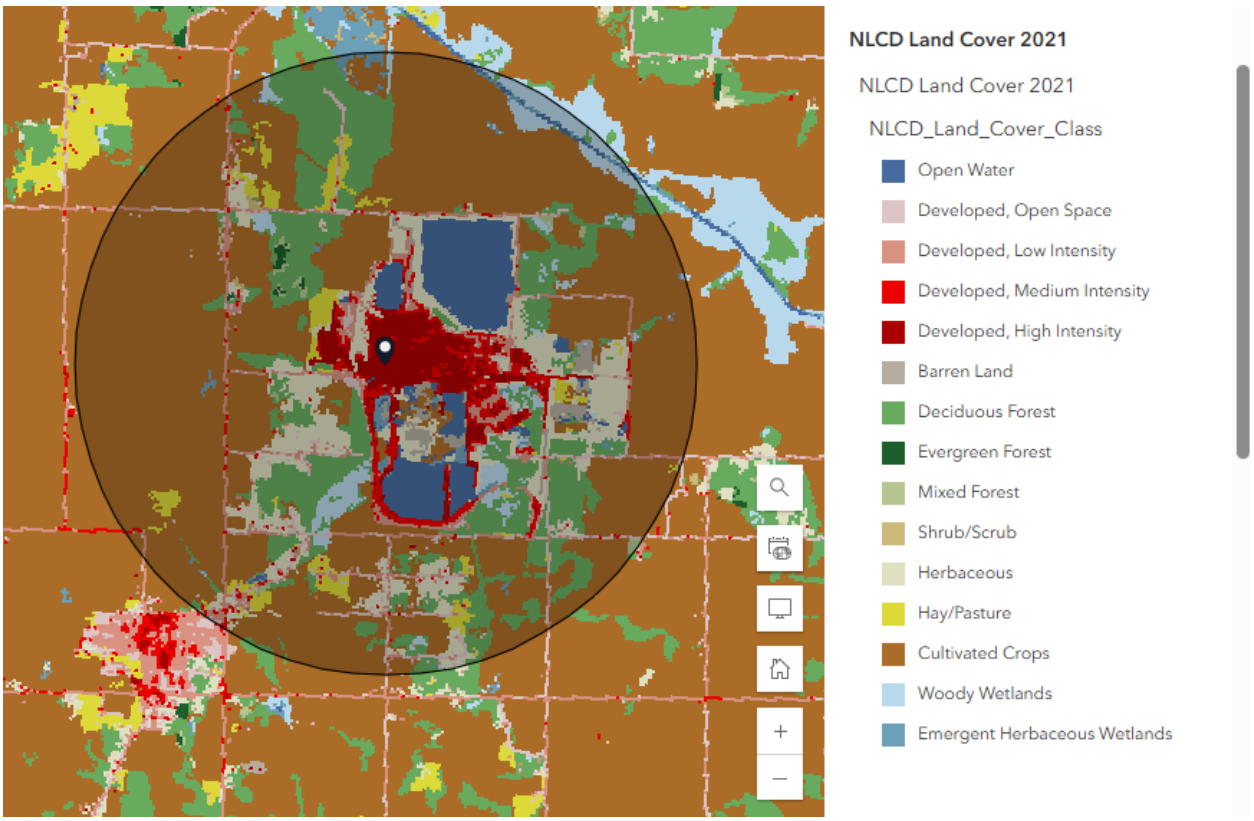
f TRI – Toxic Release Information

Section H – Summary of Air Quality Analysis

NIPSCO - Schahfer applied for a permit to modify its generating station facility in Jasper County, Indiana. The proposed modification had emissions above the significant emission rates for VOCs as all other pollutant emissions from the modification netted out from the shutdown of Schahfer's Unit 15, 17 and 18 coal-fired units. Dispersion modeling is not required for VOCs; these emissions are only analyzed for secondary formation of ozone. Therefore, IDEM concludes through its air quality analysis review that Schahfer's proposed modification will not violate or threaten national ambient air quality standards or consume PSD increment beyond what is available and allowed for any applicable pollutant.

Analysis of secondarily formed ozone was conducted and determined the proposed project would not cause or contribute to a violation of the 8-hour Ozone NAAQS. An additional impacts analysis on economic growth, vegetation, soils, visibility, wildlife, and HAPs in the area was examined and no adverse impacts on the surrounding area are to be expected on the primary or secondary air quality standards for any applicable pollutants.

Appendix A
Land Use Determination Surrounding NIPSCO – Schahfer Generating Station



INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • Fax (317) 233-6647 • www.idem.IN.gov

Mike Braun
Governor

Clint Woods
Commissioner

April 21, 2026

Keith Weber
Northern Indiana Public Service Company LLC RM Schahfer Generating Station
801 E 86th Ave
Merrillville, IN 46410

Re: Public Notice
Northern Indiana Public Service Company LLC RM Schahfer Generating Station
Permit Level: TV Significant Source Modification (Major PSD/EO) & TV Significant Permit Modification
Permit Number: 073-49556-00008 & 073-49651-00008

Dear Keith Weber:

Enclosed is the Notice of 30-Day Period for Public Comment for your draft air permit.

Our records indicate that you are the contact person for this application. However, if you are not the appropriate person within your company to receive this document, please forward it to the correct person. The Notice of 30-Day Period for Public Comment has also been sent to the OAQ Permits Branch Interested Parties List and, if applicable, your Consultant/Agent and/or Responsible Official/Authorized Individual.

The preliminary findings, including the draft permit, technical support document, emission calculations, and other supporting documents, **are available electronically at**:

IDEM's online searchable database: https://www.in.gov/apps/idem/caats/ . Choose Search Option **by Permit Number**, then enter permit 49556 & 49651

A copy of the application and preliminary findings is also available via IDEM's Virtual File Cabinet (VFC) located at https://www.in.gov/idem/legal/public-records/virtual-file-cabinet/. Once you have accessed VFC, you will then have the option to search for source related documents using a variety of criteria. To find documents related to this air permit, click on "Advanced Search," specify "OAQ" in the Program search field, specify the five-digit permit number 49556 & 49651 in the Permit # search field, then click the Search button at the top or bottom of the webpage.

If you have requested to receive a hard copy of these documents, the preliminary findings are enclosed.

The Public Notice period will begin the date the Notice is published on the IDEM Official Public Notice website. Publication has been requested and is expected within 2-3 business days. You may check the exact Public Notice begins and ends date here: https://www.in.gov/idem/public-notices/

Please note that as of April 17, 2019, IDEM is no longer required to publish the notice in a newspaper.

OAQ has submitted the draft permit package to the Jasper County Public Library – Wheatfield Public Library, 350 S Bierma St in Wheatfield, IN 46392. As a reminder, you are obligated by 326 IAC 2-1.1-6(c) to place a copy of the complete permit application at this library no later than ten (10) days after submittal of the application or additional information to our department. We highly recommend that even if you have already placed these materials at the library, that you confirm with the library that these materials

are available for review and request that the library keep the materials available for review during the entire permitting process.

Please review the draft permit documents carefully. This is your opportunity to comment on the draft permit and notify the OAQ of any corrections that are needed before the final decision. Questions or comments about the enclosed documents should be directed to Alaoui, Hachem, Indiana Department of Environmental Management, Office of Air Quality, Indiana Government Center North, 100 N. Senate Avenue, Room 13W, Indianapolis, Indiana, 46204-2251 or call (800) 451-6027, and ask for extension 2-2827 or dial (317) 232-2827.

Sincerely,

Cheri Mosier

Cheri Mosier
Permits Branch
Office of Air Quality

Enclosures
PN Applicant Cover Letter

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

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Mike Braun
Governor

Clint Woods
Commissioner

April 21, 2026

To: Jasper County Public Library – Wheatfield Public Library

From: Jenny Acker, Branch Chief
Permits Branch
Office of Air Quality

Subject: **Important Information to Display Regarding a Public Notice for an Air Permit**

Applicant Name: **Northern Indiana Public Service Company LLC RM Schahfer Generating Station**
Permit Number: **073-49556-00008 & 073-49651-00008**

Enclosed is a copy of important information to make available to the public. This proposed project is regarding a source that may have the potential to significantly impact air quality. Librarians are encouraged to educate the public to make them aware of the availability of this information. The following information is enclosed for public reference at your library:

- Notice of a 30-day Period for Public Comment
- Draft Permit and Technical Support Document

You will not be responsible for collecting any comments from the citizens. Please refer all questions and request for the copies of any pertinent information to the person named below.

Members of your community could be very concerned in how these projects might affect them and their families. **Please make this information readily available until you receive a copy of the final package.**

If you have any questions concerning this public review process, please contact Joanne Smiddie-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185. Questions pertaining to the permit itself should be directed to the contact listed on the notice.

Enclosures
PN Library updated 1/13/2025

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Mike Braun
Governor

Clint Woods
Commissioner

Notice of Public Comment

April 21, 2026
Northern Indiana Public Service Company LLC RM Schahfer Generating Station
073-49556-00008 & 073-49651-00008

To: Interested Parties:

You are receiving this notice because you asked to be on IDEM's notification list for this company and/or county; or because your property is nearby the company being permitted; or because you represent a local/regional government entity. The Indiana Department of Environmental Management, Office of Air Quality, invites your comments on the draft air permit.

Enclosed is a Notice of Public Comment, which has posted on IDEM's Public Notice website at https://www.in.gov/idem/public-notices/.

The application and supporting documentation for this proposed permit have been placed at the library indicated in the Notice. These documents more fully describe the project, the applicable air pollution control requirements and how the applicant will comply with these requirements.

If you would like to comment on this draft permit, please contact the person named in the enclosed Public Notice. Thank you for your interest in the Indiana's Air Permitting Program.

Please Note: *If you would like to be removed from the Air Permits mailing list, please contact Joanne Smiddie-Brush with the Air Permits Administration Section at 1-800-451-6027, ext. 3-0185 or via e-mail at JBRUSH@IDEM.IN.GOV. If you have recently moved and this Notice has been forwarded to you, please notify us of your new address and if you wish to remain on the mailing list. Mail that is returned to IDEM by the Post Office with a forwarding address in a different county will be removed from our list unless otherwise requested.*

Enclosure
PN Interested Parties Cover Letter 1/13/2025

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Mike Braun
Governor

Clint Woods
Commissioner

AFFECTED STATE NOTIFICATION OF PUBLIC COMMENT PERIOD
DRAFT INDIANA AIR PERMIT

April 21, 2026

A 30-day public comment period has been initiated for:

Permit Number: **073-49556-00008 & 073-49651-00008**
Applicant Name: **Northern Indiana Public Service Company LLC RM Schahfer Generating Station**
Location: **Wheatfield, Jasper County, Indiana**

The public notice, draft permit and technical support documents can be accessed via the **IDEM Air Permits Online** site at:
https://www.in.gov/ai/appfiles/idem-caats/

Questions or comments on this draft permit should be directed to the person identified in the public notice by telephone or in writing to:

Indiana Department of Environmental Management
Office of Air Quality, Permits Branch
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

Visit **on.IN.gov/survey** or scan the QR code to provide feedback.
We appreciate your input!

Mail Code 61-53 page 1 of 2

IDEM Staff	CMOSIER 4/21/2026 Northern Indiana Public Service Company LLC RM Schahfer Generating Station 073-49556-00008 & 073-49651-00008 (draft)		AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**

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1		Keith Weber Northern Indiana Public Service Company LLC RM Sch 801 E 86th Ave Merrillville IN 46410 (Source CAATS)									
2		Brian McCaul Vice President of Operations Northern Indiana Public Service Company LLC RM Sch 801 E 86th Ave Merrillville IN 46410 *(RO CAATS)*									
3		Ms. Lana Gawronski 9296 N 900 W DeMotte IN 46310 *(Affected Party)*									
4		Mr. Aaron Webster 7149 W 1000 N DeMotte IN 46310 *(Affected Party)*									
5		The Echterling Residence 9180 W 950 N DeMotte IN 46310 *(Affected Party)*									
6		Current Resident 548 N Oak Dr Plymouth IN 46563 *(Affected Party)*									
7		Mr. Lawrence A Vanore Sommer & Barnard Ackerson 1 Indiana Square, Ste 3500 Indianapolis IN 46204-5198 *(Affected Party)*									
8		State Representative District 16 PO Box 1 Rensselaer IN 47978 *(Legislator)*									
9		Jasper County Commissioners 115 W Washington St Rensselaer IN 47978 *(Local Official)*									
10		Jasper County Health Department 910 S Sparling Ave #1 Rensselaer IN 47978-9132 *(Health Department)*									
11		Mr. Donald Speacht, Jr 11751 N CR 500 E San Pierre IN 46374 *(Affected Party)*									
12		The Banks Family 11846 N CR 100 E Wheatfield IN 46392 *(Affected Party)*									
13		Ms. Kay Asher 4036 Heritage Dr N Wheatfield IN 46392 (Affected Party)									
14		Ms. Maryann Desalvo 10145 N 200 E Wheatfield IN 46392 *(Affected Party)*									
15		Victor & Cleone Downing 1333 E 1225 N Wheatfield IN 46392 *(Affected Party)*									

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Mail Code 61-53 page 2 of 2

IDEM Staff	CMOSIER 4/21/2026 Northern Indiana Public Service Company LLC RM Schahfer Generating Station 073-49556-00008 & 073-49651-00008 (draft)		AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
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1		Deborah PO Box 307 Wheatfield IN 46392 (Affected Party)									
2		George & Joyce Gourko 2039 S 9th St Lafayette IN 47905 *(Affected Party)*									
3		Mr. Scott Helton PO Box 307 Wheatfield IN 46392 *(Affected Party)*									
4		Mr. Bob Hetrick 10274 N 200 E Wheatfield IN 46392 *(Affected Party)*									
5		Ms. Monica Jones 9250 N 100 W Wheatfield IN 46392 *(Affected Party)*									
6		Michael & Kathleen Teiron 4073 E 425 N Wheatfield IN 46392 *(Affected Party)*									
7		Robert & Barbara Witvoet 14240 N SR 49 Wheatfield IN 46392 *(Affected Party)*									
8		Sharon Williams 22745 Frederick Rd Steger IL 60475 *(Affected Party)*									
9		Darlene & Scott Holmes 9161 N 900 W Demotte IN 46310 *(Affected Party)*									
10		Kenny Haun Or Current Resident PO Box 280 Rensselaer IN 47978 *(Affected Party)*									
11		Tom & Gail Clark 1186 E CR 1250 N Wheatfield IN 46392 *(Affected Party)*									
12		Wheatfield Town Council 170 S Grace St Wheatfield IN 46392 *(Local Official)*									
13		Jasper County Public Library - Wheatfield 350 S Bierma St Wheatfield IN 46392 (Library)									
14		Save the Dunes 444 Barker Rd Michigan City IN 46360 *(Affected Party)*									
15		La Porte County Herald-Dispatch 422 Franklin St, Ste B Michigan City IN 46360 *(Affected Party)*									

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.

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