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

To:	Interested Parties
Date:	May 13, 2026
From:	Jenny Acker, Chief Permits Branch Office of Air Quality
Source Name:	Maple Creek Energy LLC
Permit Level:	TV Significant Source Modification (Major PSD/EO)
Permit Number:	153-49550-00056
Source Location:	W CR 1040 N 0.5 miles South and SR 63 0.4 miles West, Fairbanks, Indiana 47849
Type of Action Taken:	Modification at an existing source

Notice of Decision: Approval - Effective Immediately

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the matter referenced above.

The final decision is available on the IDEM website at: https://www.in.gov/apps/idem/caats/. To view the document, choose Search Option by **Permit Number**, then enter permit 49550

The final decision is also available via IDEM's Virtual File Cabinet (VFC) located at https://www.in.gov/idem/legal/public-records/virtual-file-cabinet/. Click on the Virtual File Cabinet button. Click on the "Search" dropdown menu in the upper left corner and select "OAQ Permit" from the list of options. Select "Public" in the "Security group" dropdown menu. Type the five-digit permit number 49550 in the Permit # search field, select "Final" in the "Permit Type" dropdown menu, then click the search button at the top or bottom of the webpage. The search will return the final issued permit and any applicable mailing list.

(continues on next page)

If you would like to request a paper copy of the permit document, please contact IDEM's Office of Records Management:

IDEM - Office of Records Management
Indiana Government Center North
100 North Senate Avenue
Indianapolis, IN 46204-2251
Phone: (317) 232-8667
Fax: (317) 233-6647
Email: IDEMFILEROOM@idem.in.gov

Pursuant to IC 13-15-5-3, this permit is effective immediately, unless a petition for stay of effectiveness is filed and granted according to IC 13-15-6-3, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

If you wish to challenge this decision, IC 4-21.5-3 and IC 13-15-6-1 require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Indiana Office of Administrative Law Proceedings, 100 N. Senate Avenue Suite N802, Indianapolis, IN 46204, **within eighteen (18) calendar days of the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

(1) the date the document is delivered to the Indiana Office of Administrative Law Proceedings (OALP) or;
(2) the date of the postmark on the envelope containing the document, if the document is mailed to OALP by U.S. mail; or
(3) The date on which the document is deposited with a private carrier, as shown by receipt issued by the carrier, if the document is sent to the OALP by private carrier.

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

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

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

Enclosures
Final-Permit 1/13/25

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

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Mike Braun
Governor

Clint Woods
Commissioner

May 13, 2026

Mr. Nick Zaborowsky
Maple Creek Energy LLC
155 Federal Street 17th Floor
Boston, MA 02110

Re: 153-49550-00056
Significant Source Modification

Dear Mr. Zaborowsky:

Maple Creek Energy was issued Part 70 Operating Permit No. T153-45909-00056 on June 19, 2023 for a stationary combined-cycle electric generating facility located at W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849. An application to modify the source was received on September 5, 2025. Pursuant to the provisions of 326 IAC 2-7-10.5, a 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) One (1) natural gas-fired combined cycle system, identified as CTG-01, approved in 2026 for construction, with a maximum heat input capacity of 4,200 MMBtu per hour, equipped with a GE combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG) and one air-cooled condenser (ACC), using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.

Under 40 CFR 60, Subpart KKKK, CTG-01 is an affected facility because it was constructed after February 18, 2005, has a maximum heat input capacity of greater than 10 MMBtu/hr, and is a stationary combustion turbine (CTG).

Under 40 CFR 60, Subpart TTTTa, CTG-01 was constructed after May 23, 2023, has a base load rating greater than 250 MMBtu/hr of fossil fuel, and serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system, and is an affected unit.

Ancillary Equipment:

(b) One (1) natural gas-fired auxiliary boiler, identified as AUX, equipped with ultra-low-NOx burners, approved in 2026 for construction, with a rated maximum heat input capacity of 96 MMBtu per hour, and exhausting to stack AUX.

Under 40 CFR 60, Subpart Dc, AUX is an affected facility because it was constructed after June 9, 1989, has a maximum design heat input capacity of less than 100 MMBtu/hr, but greater than 10 MMBtu/hr, and is considered a small steam generating unit.

(c) One (1) diesel-fired emergency generator using ultra-low-sulfur-distillate (ULSD), identified as EG, approved in 2026 for construction, with a maximum output rating of 2,012 horsepower (hp) and exhausting to stack EG.

Under 40 CFR 60, Subpart IIII, EG is an affected facility because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and is not a fire pump engine.

Under 40 CFR 63, Subpart ZZZZ, EG is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

(d) One (1) diesel-fired emergency fire pump engine using ultra-low-sulfur-distillate (ULSD), identified as FP, approved in 2026 for construction, with a maximum output rating of 420 horsepower (hp), and exhausting to stack FP.

Under 40 CFR 60, Subpart IIII, FP is an affected facility because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, and was manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Under 40 CFR 63, Subpart ZZZZ, FP is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

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.

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 "49550" 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 Tamera Wessel, 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) 234-8530 or (800) 451-6027, and ask for Tamera Wessel.

Sincerely,

Heath Hartley, Section Chief
Permits Branch
Office of Air Quality

Attachments: Significant Source Modification and Technical Support Document

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

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Mike Braun
Governor

Clint Woods
Commissioner

PSD/Significant Source Modification to a Part 70 Source

OFFICE OF AIR QUALITY

Maple Creek Energy LLC
W CR 1040 N 0.5 miles South and SR 63 0.4 miles West
Fairbanks, Indiana 47849

(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.

Significant Source Modification No.: 153-49550-00056 Master Agency Interest ID: 130881	
Issued by: Heath Hartley, Section Chief Permits Branch Office of Air Quality	Issuance Date: May 13, 2026

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Attachment D: 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

Attachment E: National Emission Standards for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ

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 combined-cycle electric generating facility.

Source Address:	W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
General Source Phone Number:	617-314-4337
SIC Code:	4911 (Electric Services)
County Location:	Sullivan
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules 1 of 28 Source Categories

A.2 Source Definition

This stationary combined-cycle electric generating facility consists of two (2) plants:

(a) Plant 1, Maple Creek Energy LLC (Source ID: 153-00056), is located at W CR 1040 N 0.5 miles South and SR 63 0.4 miles West, Fairbanks, Indiana 47849; and

(b) Plant 2, Maple Creek Energy II LLC (Source ID: 153-00064), is/will be located at W CR 1040 N 0.5 miles South and SR 63 0.4 miles West, Fairbanks, Indiana 47849.

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

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

(a) One (1) natural gas-fired combined cycle system, identified as CTG-01, approved in 2026 for construction, with a maximum heat input capacity of 4,200 MMBtu per hour, equipped with a GE combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG) and one air-cooled condenser (ACC), using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.

Under 40 CFR 60, Subpart KKKK, CTG-01 is an affected facility because it was constructed after February 18, 2005, has a maximum heat input capacity of greater than 10 MMBtu/hr, and is a stationary combustion turbine (CTG).

Under 40 CFR 60, Subpart TTTTa, CTG-01 was constructed after May 23, 2023, has a base load rating greater than 250 MMBtu/hr of fossil fuel, and serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system, and is an affected unit.

Ancillary Equipment:

(b) One (1) natural gas-fired auxiliary boiler, identified as AUX, equipped with ultra-low-NOx burners, approved in 2026 for construction, with a rated maximum heat input capacity of 96 MMBtu per hour, and exhausting to stack AUX.

Under 40 CFR 60, Subpart Dc, AUX is an affected facility because it was constructed after June 9, 1989, has a maximum design heat input capacity of less than 100 MMBtu/hr, but greater than 10 MMBtu/hr, and is considered a small steam generating unit.

(c) One (1) diesel-fired emergency generator using ultra-low-sulfur-distillate (ULSD), identified as EG, approved in 2026 for construction, with a maximum output rating of 2,012 horsepower (hp) and exhausting to stack EG.

Under 40 CFR 60, Subpart IIII, EG is an affected facility because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and is not a fire pump engine.

Under 40 CFR 63, Subpart ZZZZ, EG is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

(d) One (1) diesel-fired emergency fire pump engine using ultra-low-sulfur-distillate (ULSD), identified as FP, approved in 2026 for construction, with a maximum output rating of 420 horsepower (hp), and exhausting to stack FP.

Under 40 CFR 60, Subpart IIII, FP is an affected facility because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, and was manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Under 40 CFR 63, Subpart ZZZZ, FP is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

A.4 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, as defined in 326 IAC 2-7-1(19):

(a) Six (6) tanks including:

Emission Unit	Quantity	Year Approved for Construction	Maximum Storage Capacity, Each (gal)
Ammonia storage tank (19% aqueous ammonia)	1	2026	30,000
Emergency Diesel Generator ULSD (integrated “belly tank”)	1	2026	2,000
Emergency Fire Pump ULSD (integrated “belly tank”)	1	2026	200
Lube Oil Tank	1	2026	10,000
Demineralized Water Tank	1	2026	500,000
Potable/Raw Water Tank	1	2026	500,000

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

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

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

(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);

SECTION B GENERAL CONDITIONS

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

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

B.2 Revocation of Permits [326 IAC 2-1.1-9(5)]

Pursuant to 326 IAC 2-1.1-9(5)(Revocation of Permits), the Commissioner may revoke this permit if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is suspended for a continuous period of one (1) year or more.

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

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

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

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

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

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

(a) This permit, T153-45909-00056, 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.5 Term of Conditions [326 IAC 2-1.1-9.5]

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

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

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

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

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

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

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

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

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

B.9 Duty to Provide Information [326 IAC 2-7-5(6)(E)]

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

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

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

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

(1) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(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.11 Annual Compliance Certification [326 IAC 2-7-6(5)]

(a) The Permittee shall annually submit a compliance certification report which addresses the status of the source's compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. The initial certification shall cover the time period from the date of final permit issuance through December 31 of the same year. All subsequent certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted no later than July 1 of each year to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
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;

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

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

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

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

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

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

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
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.

(b) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions. The PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(33).

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

B.13 Reserved

B.14 Permit Shield [326 IAC 2-7-15][326 IAC 2-7-20][326 IAC 2-7-12]

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

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

(b) 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.15 Prior Permits Superseded [326 IAC 2-1.1-9.5][326 IAC 2-7-10.5]

(a) All terms and conditions of permits established prior to T153-45909-00056 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

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

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

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

B.16 Termination of Right to Operate [326 IAC 2-7-10][326 IAC 2-7-4(a)]

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

B.17 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)][326 IAC 2-7-8(a)][326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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.18 Permit Renewal [326 IAC 2-7-3][326 IAC 2-7-4][326 IAC 2-7-8(e)]

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(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.19 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.20 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)][326 IAC 2-7-12(b)(2)]

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

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

B.21 Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]

(a) The Permittee may make any change or changes at the source that are described in 326 IAC 2-7-20(b) or (c) without a prior permit revision, if each of the following conditions is met:

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

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

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

(4) The Permittee notifies the:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
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.22 Source Modification Requirement [326 IAC 2-7-10.5]

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

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

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

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

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

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

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

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

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

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

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

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
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.25 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)][326 IAC 2-1.1-7]

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

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

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

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

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

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

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

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

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

C.2 Opacity [326 IAC 5-1]

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(A) Asbestos removal or demolition start date;

(B) Removal or demolition contractor; or

(C) Waste disposal site.

(c) The Permittee shall ensure that the notice is postmarked or delivered according to the guidelines set forth in 326 IAC 14-10-3(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.8 Performance Testing [326 IAC 3-6]

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

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
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. 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.9 Compliance Requirements [326 IAC 2-1.1-11]

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

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

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

(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).

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

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

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

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

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

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

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

(b) These ERPs shall be submitted for approval to:

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

no later than 180 days from the date on which this source commences operation.

The ERP does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(33).

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

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

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

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

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

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

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

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

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

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

(1) initial inspection and evaluation;

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

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

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

(1) monitoring results;

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

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

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

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

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

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

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

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

The response action documents submitted pursuant to this condition do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(33).

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

C.16 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 results 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 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.17 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]

Pursuant to 326 IAC 2-6-3(b)(3), starting in 2006 and every three (3) years thereafter, the Permittee shall submit by July 1 an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:

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

(2) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(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.18 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [326 IAC 2-2][326 IAC 2-3]

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

(AA) All calibration and maintenance records.

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

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

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

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

(BB) The dates analyses were performed.

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

(DD) The analytical techniques or methods used.

(EE) The results of such analyses.

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

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

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

(c) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A), 326 IAC 2-2-8 (b)(6)(B), 326 IAC 2-3-2 (l)(6)(A), and/or 326 IAC 2-3-2 (l)(6)(B)) that a “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a “major modification” (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

(1) Before beginning actual construction of the “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, document and maintain the following records:

(A) A description of the project.

(B) Identification of any emissions unit whose emissions of a regulated new source review pollutant could be affected by the project.

(C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including:

(i) Baseline actual emissions;

(ii) Projected actual emissions;

(iii) Amount of emissions excluded under section 326 IAC 2-2-1(pp)(2)(A)(iii) and/or 326 IAC 2-3-1 (kk)(2)(A)(iii); and

(iv) An explanation for why the amount was excluded, and any netting calculations, if applicable.

(d) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A) and/or 326 IAC 2-3-2 (l)(6)(A)) that a “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a “major modification” (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

(1) Monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any existing emissions unit identified in (1)(B) above; and

(2) Calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operations after the change, or for a period of ten (10) years following resumption of regular operations after the change if the project increases the design capacity of or the potential to emit that regulated NSR pollutant at the emissions unit.

C.19 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2][326 IAC 2-3]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under Section 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.

(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) The first report shall cover the period commencing on the date of issuance of this permit or the date of initial start-up, whichever is later, and ending on the last day of the reporting period. Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit, “calendar year” means the twelve (12) month period from January 1 to December 31 inclusive.

(e) If the Permittee is required to comply with the recordkeeping provisions of (d) in Section C - General Record Keeping Requirements for any “project” (as defined in 326 IAC 2-2-1 (oo) and/or 326 IAC 2-3-1 (jj)) at an existing emissions unit, and the project meets the following criteria, then the Permittee shall submit a report to IDEM, OAQ:

(1) The annual emissions, in tons per year, from the project identified in (c)(1) in Section C- General Record Keeping Requirements exceed the baseline actual emissions, as documented and maintained under Section C- General Record Keeping Requirements (c)(1)(C)(i), by a significant amount, as defined in 326 IAC 2-2-1 (ww) and/or 326 IAC 2-3-1 (pp), for that regulated NSR pollutant, and

(2) The emissions differ from the preconstruction projection as documented and maintained under Section C - General Record Keeping Requirements (c)(1)(C)(ii).

(f) The report for project at an existing emissions *unit* shall be submitted no later than sixty (60) days after the end of the year and contain the following:

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

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

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

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

Reports required in this part shall be submitted to:

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

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

Stratospheric Ozone Protection

C.20 Compliance with 40 CFR 82 and 326 IAC 22-1

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

SECTION D.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.)

General Construction Conditions

D.0.1 Permit No Defense

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

Effective Date of the Permit

D.0.2 Effective Date of the Permit [IC 13-15-5-3]

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

D.0.3 Modifications to Construction Conditions [326 IAC 2]

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

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) natural gas-fired combined cycle system, identified as CTG-01, approved in 2026 for construction, with a maximum heat input capacity of 4,200 MMBtu per hour, equipped with a GE combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG) and one air-cooled condenser (ACC), using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.

Under 40 CFR 60, Subpart KKKK, CTG-01 is an affected facility because it was constructed after February 18, 2005, has a maximum heat input capacity of greater than 10 MMBtu/hr, and is a stationary combustion turbine (CTG).

Under 40 CFR 60, Subpart TTTTa, CTG-01 was constructed after May 23, 2023, has a base load rating greater than 250 MMBtu/hr of fossil fuel, and serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system, and is an affected unit.

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

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

D.1.1 PSD and VOC BACT [326 IAC 2-2-3] [326 IAC 8-1-6]

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), and 326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbine shall be as follows:

(a) CTG-01 shall combust pipeline-quality natural gas.

(b) PM, PM_{10} and $PM_{2.5}$ emissions from the CTG-01 shall be limited through the use of good combustion practices.

(c) PM emissions from the CTG-01 shall not exceed 0.0058 lb/MMBtu, excluding periods of startup and shutdown.

(d) PM_{10} emissions from the CTG-01 shall not exceed 0.0058 lb/MMBtu, excluding periods of startup and shutdown.

(e) The $PM_{2.5}$ emissions from the CTG-01 shall not exceed 0.0058 lb/MMBtu, excluding periods of startup and shutdown.

(f) The NOx emissions from CTG-01 shall be controlled by a Selective Catalytic Reduction system, dry-low-NOx combustors, and good combustion practices.

(g) The NOx emissions from CTG-01 shall not exceed 2.0 ppmvd @ 15% O_2 based on a 3-hr average, excluding periods of startup and shutdown.

(h) NOx emissions from CTG-01 shall not exceed 30.9 lb/hr, excluding periods of startup and shutdown.

(i) The VOC emissions from the CTG-01 shall be controlled by catalytic oxidation and good combustion practices.

(j) VOC emissions from the CTG-01 shall not exceed 0.0013 pounds per MMBtu, excluding periods of startup and shutdown.

(k) VOC emissions from the CTG-01 shall not exceed 1.0 ppmvd, excluding periods of startup and shutdown.

(l) The CO emissions from CTG-01 shall be controlled using good combustion practices and an oxidation catalyst.

(m) CO emissions from CTG-01 shall not exceed 2.0 ppmvd @ 15% O2 based on a 3-hr average, excluding periods of startup and shutdown.

(n) CO emissions from the CTG-01 shall not exceed 0.0044 pounds per MMBtu, excluding periods of startup and shutdown.

(o) SO_2 and H2SO4 from CTG-01 shall be controlled through the use of pipeline-quality natural gas.

(p) SO_2 emissions from the CTG-01 shall not exceed 0.0019 lb/MMBtu.

(q) H_2SO_4 emissions from the CTG-01 shall not exceed 0.0013 lb/MMBtu.

(r) CO_2e emissions from the CTG-01 shall not exceed 800 lb/MW-hr (gross) corrected to ISO conditions.

(s) CO_2e emissions from CTG-01 shall not exceed 2,065,094 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(t) CO_2e emissions from CTG-01 shall be limited through the use of low-carbon fuel (natural gas) with high-efficiency, combined cycle generation.

D.1.2 Startup and Shutdown Limitations for Combustion Turbine [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbine shall be as follows:

(a) The PM, PM_{10}, and $PM_{2.5}$ emissions from the combined cycle combustion turbine stack shall each not exceed 1.9 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

(b) The NOx emissions from the combined cycle combustion turbine stack shall not exceed 35.8 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

(c) The VOC emissions from the combined cycle combustion turbine stack shall not exceed 18.8 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

(d) The CO emissions from the combined cycle combustion turbine stack shall not exceed 52.2 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

D.1.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

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

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

D.1.4 NO_X Control

In order to assure compliance with Conditions D.1.1(f), (g), and (h), the dry low NO_X burners for NO_X control shall be in operation and control emissions from the natural gas-fired combined cycle combustion turbine (CTG-01) at all times the natural gas-fired combined cycle combustion turbine (CTG-01) is in operation.

D.1.5 Ammonia Slip Emissions

In order to assure compliance with Conditions D.1.1(f), (g), and (h), Ammonia Slip emissions from the natural gas-fired combined cycle combustion turbine (CTG-01) shall not exceed 5.0 ppmvdc at all times the natural gas-fired combined cycle combustion turbine (CTG-01) is in operation.

D.1.6 VOC and CO Control

In order to assure compliance with Conditions D.1.1(j) through (n), the catalytic oxidation system for VOC and CO control shall be in operation and control emissions from the natural gas-fired combined cycle combustion turbine (CTG-01) at all times the natural gas-fired combined cycle combustion turbine (CTG-01) is in operation.

D.1.7 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Conditions D.1.1(r) and (s), the following equation shall be used to determine the CO_2e emissions from the CCCT:

CO_2e emissions (tons/month) = [(Fuel Usage (mmscf/month)
x Heat Content (mmbtu/mmscf))
x (CO_2 EF (lb/mmbtu) x CO_2 GWP + CH_4 EF (lb/mmbtu)
x CH_4 GWP + N_2O EF (lb/mmbtu) x N_2O GWP)]
x 1/2000 (ton/lb)

Where:

Fuel Usage (mmscf/month) = monthly fuel usage data from company records
Heat Content (mmbtu/mmscf) = standard value in AP-42 for natural gas (1,020 Btu/scf) or vendor data, if available
CO_2 EF (lb/mmbtu) = emission factor from GHG Mandatory Reporting Rule (MRR) (40 CFR 98, Subpart C) for natural gas
CH_4 EF (lb/mmbtu) = emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
N_2O EF (lb/mmbtu) = emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
CO_2 GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)

D.1.8 Startup and Shutdown

(a) To determine the compliance status with Condition D.1.2(a), the following equation shall be used to determine the PM, PM10, and PM2.5 emissions from the startup and shutdown events from CTG-01:

$PM/PM_{10}/PM_{2.5}$ (tons/month) = [SU_C (hrs/month) x EFc (lb/hr) + SU_W (hrs/month) x EFw (lb/hr) + SU_H (hrs/month) x EF_H (lb/hr) + SD (hrs/month) x EF_{SD} (lb/hr)] x 1/2000 (ton/lb)

Where:

SUc =	Hours of cold startup per month
EFc (lb/hr) =	$PM/PM_{10}/PM_{2.5}$ emissions per hour of cold startup (13.5 pounds per hour per vendor provided data)
SUw =	Hours of warm startup per month
EF_W (lb/hr) =	$PM/PM_{10}/PM_{2.5}$ emissions per hour of warm startup (13.5 pounds per hour per vendor provided data)
SU_H =	Hours of hot startup per month
EF_H (lb/hr) =	$PM/PM_{10}/PM_{2.5}$ emissions per hour of hot startup (13.6 pounds per hour per vendor provided data)
SU_{SD} =	Hours of shutdown per month
EF_{SD} (lb/hr) =	$PM/PM_{10}/PM_{2.5}$ emissions per hour of shutdown (12.5 pounds per hour per vendor provided data)

(b) To determine the compliance status with Condition D.1.2(c), the following equation shall be used to determine the VOC emissions from the startup and shutdown events from CTG-01:

VOC (tons/month) = [SU_C (hr/month) x EFc (lb/hr) + SU_W (hr/month) x EFw (lb/hr) + SU_H (hr/month) x EF_H (lb/hr) + SD (hr/month) x EF_{SD} (lb/hr)] x 1/2000 (ton/lb)

Where:

SUc =	Hours of cold startup per month
EFc (lb/hr) =	VOC emissions per hour of cold startup (85.7 pounds per hour per vendor provided data)
SUw =	Hours of warm startup per month
EF_W (lb/hr) =	VOC emissions per hour of warm startup (85 pounds per hour per vendor provided data)
SU_H =	Hours of hot startup per month
EF_H (lb/hr) =	VOC emissions per hour of hot startup (160 pounds per hour per vendor provided data)
SU_{SD} =	Hours of shutdown per month
EF_{SD} (lb/hr) =	VOC emissions per hour of shutdown (300 pounds per hour per vendor provided data)

(c) A startup is defined as the operation in the period beginning when continuous fuel flow to the combustion turbine is initiated and ending when the CCCT achieves steady-state operating condition:

(1) A cold start is defined as when the combustion turbine has been shut down for more than 72 hours.

(2) A warm start is defined as when the combustion turbine has been shut down for a period from 8 to 72 hours.

(3) A hot start is defined as when the combustion turbine has been shut down for less than 8 hours.

(d) Steady-state is defined as the period of time and load conditions when the combustion turbine is operating in emissions compliance.

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

(f) An event is defined as exactly one (1) startup or exactly one (1) shutdown.

D.1.9 Continuous Emissions Monitoring [326 IAC 3-5] [326 IAC 2-7-6(1), (6)] [326 IAC 2-2-3] [40 CFR 60, Subpart TTTTa (4Ta)] [40 CFR 60, Subpart KKKK (4K)]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous emission monitoring systems for the natural gas-fired combined cycle combustion turbine (CTG-01) shall be calibrated, maintained, and operated for measuring NO_X and CO emissions, 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 TTTTa (4Ta), and 40 CFR 60, Subpart KKKK (4K).

D.1.10 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Conditions D.1.1(c), (d) and (e) within 60 days after achieving the maximum production rate of the emission unit, but not later than 180 days after initial start-up of the natural gas-fired combined cycle combustion turbine (CTG-01), the Permittee shall perform PM, PM_{10}, and $PM_{2.5}$ testing of the natural gas-fired combined cycle combustion turbine (CTG-01), utilizing methods as approved by the Commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration. PM_{10} and $PM_{2.5}$ includes filterable and condensable PM.

(b) In order to demonstrate compliance with Conditions D.1.1(j) and (k), within 60 days after achieving the maximum production rate of the emission unit, but not later than 180 days after initial start-up of the natural gas-fired combined cycle combustion turbine (CTG-01), the Permittee shall perform VOC testing of the natural gas-fired combined cycle combustion turbine (CTG-01), utilizing methods as approved by the Commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

(c) In order to demonstrate compliance with Conditions D.1.1(q), within 60 days after achieving the maximum production rate of the emission unit, but not later than 180 days after initial start-up, the Permittee shall perform H_2SO_4 testing on CTG-01, utilizing methods as approved by the Commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

(d) 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.

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

D.1.11 Oxidation Catalyst Parametric Monitoring

(a) A continuous monitoring system shall be calibrated, maintained, and operated on each oxidation catalyst for measuring operating temperature while operating CTG-01. For the purpose of this condition, continuous means no less often than every 15 minutes. The output of this system shall be recorded as a 3-hour average. From the date of startup of CTG-01 until the stack test results are available, the Permittee shall operate the oxidation catalyst at or above the 3-hour average temperature of 500°F.

(b) The Permittee shall determine the 3-hour average temperature from the latest valid stack test that demonstrates compliance with limits in Conditions D.1.1(j), (k), (m), and (n).

(c) On and after the date the approved stack test results are available, the Permittee shall operate the oxidation catalyst at or above the three (3) hour average temperature as established during the most recent compliant stack test.

(d) If the 3-hour average temperature falls below the above mentioned 3-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 temperature average below the above mentioned 3-hour average is not considered a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

D.1.12 NO_X and CO Continuous Emissions Monitoring (CEMS) Equipment Downtime

(a) In the event that a breakdown of a NO_X and CO 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 NO_X and CO 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 NO_X and CO CEMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary NO_X and CO CEMS, the Permittee shall follow good air pollution control practices.

(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 normal operations, with at least four (4) hours between each set of readings, until a NOx and CO CEMS is online.

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

D.1.13 Record Keeping Requirement

(a) In order to document the compliance status with Conditions D.1.1(r) and (s), the Permittee shall maintain monthly records of the following:

(1) The amount of fuel combusted in the combined cycle combustion turbine.

(2) The CO_2e emissions from CTG-01.

(b) To document compliance with Condition D.1.2, the Permittee shall maintain records of the following:

(1) The type of operation (i.e. startup, shutdown) with supporting operational data;

(2) The total number of minutes for startup and shutdown operation per event; and

(3) The CEMS data, fuel flow meter data, and/or Method 19 calculations used to determine the mass emissions rate corresponding to each startup and shutdown operating period.

(4) The monthly records of the combined startup and shutdown PM, PM10, and PM2.5 emissions from CTG-01.

(5) The monthly records of the combined startup and shutdown VOC emissions from CTG-01.

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

(d) In the event that a breakdown of the NO_X and CO CEMS occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(e) The Permittee shall maintain the monthly records of the NO_X and CO emissions from the CCCT based on the CEM data.

(f) In order to document the compliance status with Condition D.1.11, the Permittee shall maintain continuous temperature records (on a 3-hour average basis) for each oxidation catalyst to demonstrate compliance.

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

D.1.14 Reporting Requirements

(a) A quarterly summary of PM, PM_{10}, $PM_{2.5}$, NOx, VOC, and CO emissions to document the compliance status with D.1.2 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.

(b) 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).

(c) 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.

(d) 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 D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(b) One (1) natural gas-fired auxiliary boiler, identified as AUX, equipped with ultra-low-NOx burners, approved in 2026 for construction, with a rated maximum heat input capacity of 96 MMBtu per hour, and exhausting to stack AUX.

Under 40 CFR 60, Subpart Dc, AUX is an affected facility because it was constructed after June 9, 1989, has a maximum design heat input capacity of less than 100 MMBtu/hr, but greater than 10 MMBtu/hr, and is considered a small steam generating unit.

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

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

D.2.1 PSD BACT [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler shall be as follows:

(a) PM, PM_{10}, and $PM_{2.5}$ emissions from the auxiliary boiler (AUX) shall be controlled through the use of pipeline-quality natural gas.

(b) PM, PM_{10}, and $PM_{2.5}$ emissions from the auxiliary boiler (AUX) shall be controlled through the use of good combustion practices.

(c) Filterable PM emissions from the auxiliary boiler (AUX) shall not exceed 0.0019 lb/MMBtu.

(d) PM_{10} emissions from the auxiliary boiler (AUX) shall not exceed 0.0075 lb/MMBtu.

(e) $PM_{2.5}$ emissions from the auxiliary boiler (AUX) shall not exceed 0.0075 lb/MMBtu.

(f) NOx emissions from the auxiliary boiler (AUX) shall not exceed 0.011 lb/MMBtu.

(g) NOx emissions from the auxiliary boiler (AUX) shall be controlled by an Ultra Low NOx Burner.

(h) CO emissions from the auxiliary boiler (AUX) shall not exceed 0.037 lb/MMBtu.

(i) CO emissions from the auxiliary boiler (AUX) shall be controlled through the use of good combustion practices.

(j) H_2SO_4 emissions from the auxiliary boiler (AUX) shall not exceed 0.00014 lb/MMBtu.

(k) H_2SO_4 emissions from the auxiliary boiler (AUX) shall be controlled through the use of only pipeline quality natural gas.

(l) CO_{2e} emissions from the auxiliary boiler (AUX) shall not exceed 11,244 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(m) CO_{2e} emissions from the auxiliary boiler (AUX) shall be controlled through the use of good combustion practices.

(n) The auxiliary boiler (AUX) shall not exceed 2,000 hours of operation per twelve (12) consecutive month period.

D.2.2 Startup, Shutdown, and Other Opacity Limits [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3(a) (Temporary Alternative Opacity Limitations), when building a new fire in a boiler, or shutting down a boiler, opacity may exceed the applicable opacity limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period. Opacity in excess of the applicable opacity limit established in 326 IAC 5-1-2 shall not continue for more than two (2) six (6)-minute averaging periods in any twenty-four (24) hour period.

(b) If a facility cannot meet the opacity limitations of 326 IAC 5-1-3(a) or (b), the Permittee may submit a written request to IDEM, OAQ, for a temporary alternative opacity limitation in accordance with 326 IAC 5-1-3(d). The Permittee must demonstrate that the alternative limit is needed and justifiable.

D.2.3 Particulate Emissions [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating), PM emissions from the natural gas-fired auxiliary boiler (AUX) shall be limited to 0.28 pounds per MMBtu heat input.

D.2.4 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

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

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

D.2.5 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with condition D.2.1(l), the following equation shall be used to determine the CO_{2e} emissions from the Auxiliary Boiler:

CO_{2e} emissions (tons/month) = [(Fuel Usage (mmscf/month)
x Heat Content (mmbtu/mmscf))
x (CO_2 EF (lb/mmbtu) x CO_2 GWP + CH_4 EF (lb/mmbtu)
x CH_4 GWP + N_2O EF (lb/mmbtu) x N_2O GWP)]
x 1/2000 (ton/lb)

Where:

Fuel Usage (mmscf/month) = monthly auxiliary boiler fuel usage data from company records
Heat Content (mmbtu/mmscf) = standard value in AP-42 for natural gas, or vendor data, if available
CO_2 EF (lb/mmbtu) = emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
CH_4 EF (lb/mmbtu) = emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
N_2O EF (lb/mmbtu) = emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
CO_2 GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)

D.2.6 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Conditions D.2.1(c), (d), and (e), within 60 days after achieving the maximum production rate of the emission unit, but not later than 180 days after the startup of natural gas-fired auxiliary boiler, the Permittee shall perform PM, PM_{10}, and $PM_{2.5}$ testing of the natural gas-fired auxiliary boiler utilizing methods approved by the commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

(b) In order to demonstrate compliance with Condition D.2.1(f), within 60 days after achieving the maximum production rate of the emission unit, but not later than 180 days after the startup of natural gas-fired auxiliary boiler, the Permittee shall perform NOx testing of the natural gas-fired auxiliary boiler utilizing methods approved by the commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

(c) In order to demonstrate compliance with Condition D.2.1(h), within 60 days after achieving the maximum production rate of the emission unit, but not later than 180 days after the startup of natural gas-fired auxiliary boiler, the Permittee shall perform CO testing of the natural gas-fired auxiliary boiler utilizing methods approved by the commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

(d) In order to demonstrate compliance with Condition D.2.1(j), within 60 days after achieving the maximum production rate of the emission unit, but not later than 180 days after the startup of natural gas-fired auxiliary boiler, the Permittee shall perform H_2SO_4 testing of the natural gas-fired auxiliary boiler utilizing methods approved by the commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

(e) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition. PM_{10} and $PM_{2.5}$ includes filterable and condensable PM.

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

D.2.7 Record Keeping Requirement

(a) To document the compliance status with Condition D.2.1(l), the Permittee shall maintain records of the monthly CO_{2e} emissions from the natural gas-fired auxiliary boiler.

(b) To document the compliance status with Condition D.2.1(n), the Permittee shall maintain records of the hours of operation of the natural gas-fired auxiliary boiler.

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

D.2.8 Reporting Requirements

A quarterly report of monthly CO_{2e} emissions and hours of operation of the auxiliary boiler (AUX) to document the compliance status with D.2.1(l) and D.2.1(n) 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(33).

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) One (1) diesel-fired emergency generator using ultra-low-sulfur-distillate (ULSD), identified as EG, approved in 2026 for construction, with a maximum output rating of 2,012 horsepower (hp) and exhausting to stack EG.

Under 40 CFR 60, Subpart IIII, EG is an affected facility because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and is not a fire pump engine.

Under 40 CFR 63, Subpart ZZZZ, EG is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

(d) One (1) diesel-fired emergency fire pump engine using ultra-low-sulfur-distillate (ULSD), identified as FP, approved in 2026 for construction, with a maximum output rating of 420 horsepower (hp), and exhausting to stack FP.

Under 40 CFR 60, Subpart IIII, FP is an affected facility because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, and was manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Under 40 CFR 63, Subpart ZZZZ, FP is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

(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 PSD BACT [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the diesel-fired emergency generator (EG) and the diesel-fired emergency fire pump (FP) shall be as follows:

(a) The emissions from the emergency generator (EG) shall not exceed the limits in the table below, through the use of state-of-the-art combustion design.

	PM	PM_{10}	$PM_{2.5}$	NOx + NMHC	CO
Emission Limit (g/hp-hr)	0.15	0.15	0.15	4.8	2.61
Emission Limit (lb/hr)	0.67	0.67	0.67	21.29	11.58

(b) The emissions from the emergency fire pump engine (FP) shall not exceed the limits in the table below, through the use of state-of-the-art combustion design.

	PM	PM_{10}	$PM_{2.5}$	NOx + NMHC	CO
Emission Limit (g/kW-hr)	0.20	0.20	0.20	4.0	3.5
Emission Limit (lb/hr)	0.14	0.14	0.14	2.72	2.38

(c) The sulfur content of diesel fuel burned in the emergency generator (EG) shall not exceed 0.0015%.

(d) The sulfur content of diesel fuel burned in the emergency fire water pump engine (FP) shall not exceed 0.0015%.

(e) The GHG BACT for the emergency generator (EG) shall be as follows:

(1) The use of a good engineering design and fuel-efficient design; and

(2) The CO_2e emissions from EG shall not exceed 125 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(f) The GHG BACT for the emergency fire water pump engine (FP) shall be as follows:

(1) The use of a good engineering design and fuel-efficient design; and

(2) CO_{2e} emissions from the emergency fire pump shall not exceed 24 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

D.3.2 Air Quality Impact Requirements [326 IAC 2-2-5]

In order to render the requirements of 326 IAC 2-2-5 (Air Quality Impact; Requirements) not applicable, the Permittee shall comply with the following:

(a) The emergency generator shall not exceed 100 hours of operation per twelve (12) consecutive month period.

(b) The emergency fire pump shall not exceed 100 hours of operation per twelve (12) consecutive month period.

Compliance with these limits, combined with the potential to emit NOx from all other emission units at this source, shall render the requirements of 326 IAC 2-2-5 (Air Quality Impact; Requirements) not applicable.

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

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

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

D.3.4 Greenhouse Gases (GHGs) Calculations

To determine compliance with Conditions D.3.1(e)(2) and D.3.1(f)(2), the following equation shall be used to determine the CO_{2e} emissions from the diesel-fired emergency generator and the diesel-fired emergency fire pump engine:

CO_{2e} emissions (tons/month) = [(Fuel Usage (gal/month)

x Heat Content (mmbtu/gal))
x (CO_2 EF (lb/mmbtu) x CO_2 GWP + CH_4 EF (lb/mmbtu)
x CH_4 GWP + N_2O EF (lb/mmbtu) x N_2O GWP)]
x 1/2000 (ton/lb)

Where:

Fuel Usage (gal/month) = monthly fire pump engine/emergency generator fuel usage data from company records
Heat Content (mmbtu/gal) = standard value in AP-42 for diesel fuel, or vendor data, if available
CO_2 EF (lb/mmbtu) = emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
CH_4 EF (lb/mmbtu) = emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
N_2O EF (lb/mmbtu) = emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
CO_2 GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)

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

D.3.5 Record Keeping Requirement

(a) To document the compliance status with Conditions D.3.1(a), (b), (c), and (d), the Permittee shall maintain the following monthly records for the diesel-fired emergency generator and the diesel-fired emergency fire pump engine.

(1) the percent sulfur content of the fuel used in each unit.
(2) the total amount of fuel used in each unit.

(b) To document the compliance status with Conditions D.3.1(e)(2) and D.3.1(f)(2), the Permittee shall maintain records of the monthly CO_{2e} emissions from the diesel-fired emergency generator and the diesel-fired emergency fire pump engine.

(c) To document the compliance status with Condition D.3.2, the Permittee shall maintain monthly records of hours of operation of the diesel-fired emergency generator and the diesel-fired emergency fire pump engine.

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

D.3.6 Reporting Requirements

A quarterly report of monthly CO_{2e} emissions and hours of operation and a quarterly summary of the information to document the compliance status with D.3.1(e)(2) and D.3.1(f)(2), 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(33).

SECTION E.1 **NSPS**

Emissions Unit Description:

(b) One (1) natural gas-fired auxiliary boiler, identified as AUX, equipped with ultra-low-NOx burners, approved in 2026 for construction, with a rated maximum heat input capacity of 96 MMBtu per hour, and exhausting to stack AUX.

Under 40 CFR 60, Subpart Dc, AUX is an affected facility because it was constructed after June 9, 1989, has a maximum design heat input capacity of less than 100 MMBtu/hr, but greater than 10 MMBtu/hr, and is considered a small steam generating unit.

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

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

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

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart 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.1.2 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 A 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)(1), (a)(3), (g), and (i)	Reporting and recordkeeping requirements.

SECTION E.2 NSPS

Emissions Unit Description:

(c) One (1) diesel-fired emergency generator using ultra-low-sulfur-distillate (ULSD), identified as EG, approved in 2026 for construction, with a maximum output rating of 2,012 horsepower (hp) and exhausting to stack EG.

Under 40 CFR 60, Subpart IIII, EG is an affected facility because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and is not a fire pump engine.

Under 40 CFR 63, Subpart ZZZZ, EG is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

(d) One (1) diesel-fired emergency fire pump engine using ultra-low-sulfur-distillate (ULSD), identified as FP, approved in 2026 for construction, with a maximum output rating of 420 horsepower (hp), and exhausting to stack FP.

Under 40 CFR 60, Subpart IIII, FP is an affected facility because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, and was manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Under 40 CFR 63, Subpart ZZZZ, FP is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

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

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

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

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

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

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

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

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

(a) EG

60.4200(a)(2)(i), (a)(4), (c)	Am I subject to this subpart?
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(a)	What is the deadline for importing or installing stationary CI ICE produced in previous model years?
60.4209(a)	What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?
60.4211(a), (c), (f), (g)(3)	What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?
60.4214(b) and (d)	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 5	Labeling and Recordkeeping Requirements for New Stationary Emergency Engines
Table 8	Applicability of General Provisions to Subpart IIII

(b) FP

60.4200(a)(2)(ii), (a)(4), (c)	Am I subject to this subpart?
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?
60.4209(a)	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?
60.4218	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 4	Emission Standards for Stationary Fire Pump Engines

Table 8	Applicability of General Provisions to Subpart IIII

SECTION E.3 NSPS

Emissions Unit Description:

(a) One (1) natural gas-fired combined cycle system, identified as CTG-01, approved in 2026 for construction, with a maximum heat input capacity of 4,200 MMBtu per hour, equipped with a GE combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG) and one air-cooled condenser (ACC), using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.

Under 40 CFR 60, Subpart KKKK, CTG-01 is an affected facility because it was constructed after February 18, 2005, has a maximum heat input capacity of greater than 10 MMBtu/hr, and is a stationary combustion turbine (CTG).

Under 40 CFR 60, Subpart TTTTa, CTG-01 was constructed after May 23, 2023, has a base load rating greater than 250 MMBtu/hr of fossil fuel, and serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system, and is an affected unit.

(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 KKKK.

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

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

E.3.2 Stationary Combustion Turbines NSPS [326 IAC 12] [40 CFR Part 60, Subpart KKKK]

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

60.4300	What is the purpose of this subpart?
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(b)	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?
60.4360	How do I determine the total sulfur content of the turbine's combustion fuel?
60.4365(a)	How can I be exempted from monitoring the total sulfur content of the fuel?
60.4375(a)	What reports must I submit?
60.4380(b) and (c)	How are excess emissions and monitor downtime defined for NOX?
60.4385	How are excess emissions and monitoring downtime defined for SO2?
60.4395	When must I submit my reports?
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

SECTION E.4 NSPS

Emissions Unit Description:

(a) One (1) natural gas-fired combined cycle system, identified as CTG-01, approved in 2026 for construction, with a maximum heat input capacity of 4,200 MMBtu per hour, equipped with a GE combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG) and one air-cooled condenser (ACC), using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.

Under 40 CFR 60, Subpart KKKK, CTG-01 is an affected facility because it was constructed after February 18, 2005, has a maximum heat input capacity of greater than 10 MMBtu/hr, and is a stationary combustion turbine (CTG).

Under 40 CFR 60, Subpart TTTTa, CTG-01 was constructed after May 23, 2023, has a base load rating greater than 250 MMBtu/hr of fossil fuel, and serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system, and is an affected unit.

(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 TTTTa.

(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.4.2 Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units 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 D to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

60.5508a	What is the purpose of this subpart?
60.5509a(a)	Am I subject to this subpart?
60.5515a	Which pollutants are regulated by this subpart?
60.5520a(a) and (b)	What CO_2 emissions standard must I meet?
60.5525a(a)(1), (b),	What are my general requirements for complying with this subpart?

(c)(1), (c)(3)(i)	
60.5535a(a), (c)(1) through (4), (d)(1)	How do I monitor and collect data to demonstrate compliance?
60.5540a	How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?
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

SECTION E.5 **NESHAP**

Emissions Unit Description:

(c) One (1) diesel-fired emergency generator using ultra-low-sulfur-distillate (ULSD), identified as EG, approved in 2026 for construction, with a maximum output rating of 2,012 horsepower (hp) and exhausting to stack EG.

Under 40 CFR 60, Subpart IIII, EG is an affected facility because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and is not a fire pump engine.

Under 40 CFR 63, Subpart ZZZZ, EG is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

(d) One (1) diesel-fired emergency fire pump engine using ultra-low-sulfur-distillate (ULSD), identified as FP, approved in 2026 for construction, with a maximum output rating of 420 horsepower (hp), and exhausting to stack FP.

Under 40 CFR 60, Subpart IIII, FP is an affected facility because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, and was manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Under 40 CFR 63, Subpart ZZZZ, FP is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

(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.5.1 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.5.2 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 E to the operating permit), which are incorporated by reference as 326 IAC 20-82 for the emission unit(s) listed above:

63.6580	What is the purpose of subpart ZZZZ?
63.6585	Am I subject to this subpart?
63.6590(a)(2)(iii) and (c)(1)	What parts of my plant does this subpart cover?
63.6595(a)(7)	When do I have to comply with this subpart?
63.6665	What parts of the General Provisions apply to me?
63.6670	Who implements and enforces this subpart?
63.6675	What definitions apply to this subpart?

SECTION F CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, and CSAPR SO_2 Group 1 Trading Program Requirements (40 CFR 97.406), (40 CFR 97.806) (Group 3 Trading Program stayed per 89 FR 87960, 11/6/24), (40 CFR 97.606)

ORIS Code: 57794

Emissions Unit Description:

(a) One (1) natural gas-fired combined cycle system, identified as CTG-01, approved in 2026 for construction, with a maximum heat input capacity of 4,200 MMBtu per hour, equipped with a GE combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG) and one air-cooled condenser (ACC), using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.

Under 40 CFR 60, Subpart KKKK, CTG-01 was constructed after February 18, 2005, has a maximum heat input capacity of greater than 10 MMBtu/hr, and is a stationary combustion turbine (CTG).

Under 40 CFR 60, Subpart TTTTa, CTG-01 was constructed after May 23, 2023, has a base load rating greater than 250 MMBtu/hr of fossil fuel, and serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system, and is an affected unit.

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

F.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.
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.

F.2 Emissions Monitoring, Reporting, and Recordkeeping Requirements

(a) The owners and operators, and the designated representative, of each CSAPR NO_X Annual source, CSAPR NOx Ozone Season Group 2 source, and CSAPR SO2 Group 1 source, and each CSAPR NO_X Annual unit at the source, CSAPR NOx Ozone Season Group 2 unit at the source, and CSAPR 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).

(b) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of CSAPR NO_X Annual allowances under 326 IAC 24-5 and to determine compliance with the CSAPR NO_X Annual emissions limitation and assurance provisions under Condition F.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.

(c) The emissions data determined in accordance with 40 CFR 97.830 through 97.835 shall be used to calculate allocations of CSAPR NO_X Ozone Season Group 2 allowances under 40 CFR 97.811 and (b) and 97.812 and to determine compliance with the CSAPR NO_X Ozone Season Group 2 emissions limitation and assurance provisions under Condition F.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.

(d) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of CSAPR SO_2 Group 1 allowances under 326 IAC 24-7 and to determine compliance with the CSAPR SO_2 Group 1 emissions limitation and assurance provisions under Condition F.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.

F.3 NO_X Annual Emissions Requirements

(a) CSAPR NO_X Annual emissions limitation.

(1) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall hold, in the source's compliance account, CSAPR 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 CSAPR NO_X Annual units at the source.

(2) If total NO_X emissions during a control period in a given year from the CSAPR NO_X Annual units at a CSAPR NO_X Annual source are in excess of the CSAPR NO_X Annual emissions limitation set forth in Condition F.3(a)(1) above, then:

(A) The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall hold the CSAPR NO_X Annual allowances required for deduction under 40 CFR 97.424(d); and

(B) The owners and operators of the source and each CSAPR 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.

(b) CSAPR NO_X Annual assurance provisions.

(1) If total NO_X emissions during a control period in a given year from all CSAPR NO_X Annual units at CSAPR 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) CSAPR 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 CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state for such control period exceed the state assurance level.

(2) The owners and operators shall hold the CSAPR NO_X Annual allowances required under Condition F.3(b)(1) 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.

(3) Total NO_X emissions from all CSAPR NO_X Annual units at CSAPR 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).

(4) 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 CSAPR NO_X Annual units at CSAPR 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 CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state during a control period exceeds the common designated representative's assurance level.

(5) To the extent the owners and operators fail to hold CSAPR NO_X Annual allowances for a control period in a given year in accordance with Conditions F.3(b)(1) through (3) 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 CSAPR NO_X Annual allowance that the owners and operators fail to hold for such control period in accordance with Conditions F.3(b)(1) through (3) 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.

(c) Compliance periods.

(1) A CSAPR NO_X Annual unit shall be subject to the requirements under Condition F.3(a) 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.

(2) A CSAPR NO_X Annual unit shall be subject to the requirements under Condition F.3(b) 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.

(d) Vintage of allowances held for compliance.

(1) A CSAPR NO_X Annual allowance held for compliance with the requirements under Condition F.3(a)(1) above for a control period in a given year must be a CSAPR NO_X Annual allowance that was allocated for such control period or a control period in a prior year.

(2) A CSAPR NO_X Annual allowance held for compliance with the requirements under Condition F.3(a)(2)(1) and (b)(1) through (3) above for a control period in a given year must be a CSAPR 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.

(e) Allowance Management System requirements. Each CSAPR 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.

(f) Limited authorization. A CSAPR 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:

(1) Such authorization shall only be used in accordance with the CSAPR NO_X Annual Trading Program; and

(2) 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.

(g) Property right. A CSAPR NO_X Annual allowance does not constitute a property right.

F.4 NO_X Ozone Season Group 2 Requirements

(a) CSAPR NO_X Ozone Season Group 2 emissions limitation.

(1) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, CSAPR 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 CSAPR NO_X Ozone Season Group 2 units at the source.

(2) If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season Group 2 units at a CSAPR NO_X Ozone Season Group 2 source are in excess of the CSAPR NO_X Ozone Season Group 2 emissions limitation set forth in Condition F.4(a)(1) above, then:

(A) The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold the CSAPR NO_X Ozone Season Group 2 allowances required for deduction under 40 CFR 97.824(d); and

(B) The owners and operators of the source and each CSAPR 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.

(b) CSAPR NO_X Ozone Season Group 2 assurance provisions.

(1) If total NO_X emissions during a control period in a given year from all CSAPR NO_X Ozone Season Group 2 units at CSAPR 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) CSAPR 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 exceeds the respective common designated representative's assurance level; and

(B) The amount by which total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state for such control period exceed the state assurance level.

(2) The owners and operators shall hold the CSAPR NO_X Ozone Season Group 2 allowances required under Condition F.4(b)(1) 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.

(3) Total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR 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).

(4) 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 CSAPR NO_X Ozone Season Group 2 units at CSAPR 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 CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state during a control

period exceeds the common designated representative's assurance level.

(5) To the extent the owners and operators fail to hold CSAPR NO_X Ozone Season Group 2 allowances for a control period in a given year in accordance with Conditions F.4(b)(1) through (3) 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 CSAPR NOX Ozone Season Group 2 allowance that the owners and operators fail to hold for such control period in accordance with Conditions F.4(b)(1) through (3) 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.

(c) Compliance Periods.

(1) A CSAPR NOx Ozone Season unit shall be subject to the requirements under Condition F.4(a) 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.

(2) A CSAPR NOx Ozone Season Group 2 unit shall be subject to the requirements under Condition F.4(b) 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 97.830(b) and for each control period thereafter.

(d) Vintage of allowances held for compliance.

(1) A CSAPR NOx Ozone Season Group 2 allowance held for compliance with the requirements under Condition F.4(a)(1) above for a control period in a given year must be a CSAPR NOx Ozone Season Group 2 Allowance that was allocated for such control period or a control period in a prior year.

(2) A CSAPR NOx Ozone Season Group 2 allowance held for compliance with the requirements under Conditions F.4(a)(2)(A) and (b)(1) through (3) above for a control period in a given year must be a CSAPR NOx Ozone Season Group 2 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.

(e) Allowances Management System Requirements.

(1) Each CSAPR 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.

(f) Limited Authorization.

(1) A CSAPR 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 CSAPR 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.

(g) Property Right.

(1) A CSAPR NOx Ozone Season Group 2 allowance does not constitute a property right.

F.5 SO_2 Emissions Requirements

(a) CSAPR SO_2 Group 1 emissions limitation.

(1) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO2 Group 1 unit at the source shall hold, in the source's compliance account, CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all CSAPR SO_2 Group 1 units at the source.

(2) If total SO_2 emissions during a control period in a given year from the CSAPR SO_2 Group 1 units at a CSAPR SO_2 Group 1 source are in excess of the CSAPR SO_2 Group 1 emissions limitation set forth in Condition F.5(a)(1) above, then:

(A) The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall hold the CSAPR 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 CSAPR 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.

(b) CSAPR SO_2 Group 1 assurance provisions

(1) If total SO_2 emissions during a control period in a given year from all CSAPR SO_2 Group 1 units at CSAPR 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) CSAPR 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—

(2) 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

(3) The amount by which total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state for such control period exceed the state assurance level.

(4) The owners and operators shall hold the CSAPR SO_2 Group 1 allowances required under Condition F.5(b)(1) 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.

(5) Total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR 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).

(6) 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 CSAPR SO_2 Group 1 units at CSAPR 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 CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.

(7) To the extent the owners and operators fail to hold CSAPR SO_2 Group 1 allowances for a control period in a given year in accordance with Conditions F.5(b)(1) through (3) 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 CSAPR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with Conditions F.5(b)(1) through (3) 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.

(c) Compliance periods.

(1) A CSAPR SO_2 Group 1 unit shall be subject to the requirements under Condition F.5(a) 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.

(2) A CSAPR SO_2 Group 1 unit shall be subject to the requirements under Condition F.5(b) 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.

(d) Vintage of allowances held for compliance.

(1) A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under Condition F.5(a)(1) above for a control period in a given year must be a

CSAPR SO_2 Group 1 allowance that was allocated for such control period or a control period in a prior year.

(2) A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under Condition F.5(a)(2)(A) and (b)(1) through (3) above for a control period in a given year must be a CSAPR 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.

(e) Allowance Management System requirements. Each CSAPR 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.

(f) Limited authorization. A CSAPR 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:

(1) Such authorization shall only be used in accordance with the CSAPR SO_2 Group 1 Trading Program; and

(2) 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.

(g) Property right. A CSAPR SO_2 Group 1 allowance does not constitute a property right.

F.6 Title V Permit Revision Requirements

(a) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_X Annual allowances in accordance with 40 CFR Part 97, Subpart AAAAA, CSAPR NO_X Ozone Season allowances in accordance with 40 CFR Part 97, Subpart EEEEE, and CSAPR SO_2 Group 1 allowances in accordance with 40 CFR Part 97, Subpart CCCCC.

(b) This permit incorporates the CSAPR 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 CSAPR 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).

F.7 Additional recordkeeping and reporting requirements

(a) Unless otherwise provided, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit, CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit, and CSAPR SO_2 Group 1 source and each CSAPR 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.

(1) 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 CSAPR NO_X Annual unit, CSAPR NOx Ozone Season Group 2 unit, and CSAPR 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.

(2) 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.

(3) 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 CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, and CSAPR SO_2 Group 1 Trading Program.

(b) The designated representative of a CSAPR NO_X Annual source and each CSAPR NO_X Annual unit, a CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit, and a CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall make all submissions required under the CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, and CSAPR 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.

F.8 Liability

(a) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual source or the designated representative of a CSAPR NO_X Annual source shall also apply to the owners and operators of such source and of the CSAPR NO_X Annual units at the source.

(b) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual unit or the designated representative of a CSAPR NO_X Annual unit shall also apply to the owners and operators of such unit.

(c) Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 source or the designated representative of a CSAPR NO_X Ozone Season Group 2 source shall also apply to the owners and operators of such source and of the CSAPR NO_X Ozone Season Group 2 units at the source.

(d) Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 unit or the designated representative of a CSAPR NO_X Ozone Season Group 2 unit shall also apply to the owners and operators of such unit.

(e) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 source or the designated representative of a CSAPR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the CSAPR SO_2 Group 1 units at the source.

(f) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 unit or the designated representative of a CSAPR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

F.9 Effect on Other Authorities

No provision of the CSAPR NO_X Annual Trading Program or exemption under 40 CFR 97.405, CSAPR NO_X Ozone Season Group 2 Trading Program or exemption under 40 CFR 97.805, and CSAPR 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 CSAPR NO_X Annual source or CSAPR NO_X Annual unit, CSAPR NO_X Ozone Season Group 2 source or CSAPR NO_X Ozone Season Group 2 unit, and CSAPR SO_2 Group 1 source or CSAPR 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.

F.10 Description of CSAPR Monitoring Provisions

The CSAPR 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 CSAPR NOx Annual Trading Program, CSAPR NOx Ozone Season Trading Program, and CSAPR SO2 Group 1 Trading Program.

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 (TR NO_X Annual Trading Program), 97.830 through 97.835 (TR NO_X Ozone Season Group 2 Trading Program), and 97.630 through 97.635 (TR 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 **https://www.epa.gov/amtic/regulations-guidance-and-monitoring-plans**.

(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), 97.835 (CSAPR NO_X Ozone Season Group 2 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 **https://www.epa.gov/petitions**.

(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), 97.830 through 97.834 (CSAPR NO_X Ozone Season Group 2 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), 97.835 (CSAPR NO_X Ozone Season Group 2 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 **https://www.epa.gov/petitions**.

(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), 97.830 through 97.834 (CSAPR NO_X Ozone Season Group 2 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.

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

Source Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana
Part 70 Permit No.: T153-45909-00056

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:

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: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit No.: T153-45909-00056

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.

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

Part 70 Quarterly Report

Source Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Part 70 Permit No.: T153-45909-00056
Facility: Natural Gas-Fired Combined Cycle Combustion Turbine (CTG-01)
Parameter: PM emissions
Limit: The PM emissions from the combined startup and shutdown events from the Natural Gas-Fired Combined Cycle Combustion Turbine (CTG-01) shall not exceed 1.9 tons per twelve (12) consecutive month period.

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: ____________________

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

Part 70 Quarterly Report

Source Name:	Maple Creek Energy LLC
Source Address:	W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Part 70 Permit No.:	T153-45909-00056
Facility:	Natural Gas-Fired Combined Cycle Combustion Turbine (CTG-01)
Parameter:	PM_{10} emissions
Limit:	The PM_{10} emissions from the combined startup and shutdown events from the Natural Gas-Fired Combined Cycle Combustion Turbine (CTG-01) shall not exceed 1.9 tons per twelve (12) consecutive month period.

QUARTER:____________________ YEAR:____________________

Month	Column 1	Column 2	Column 1 + Column 2
	PM_{10} Emissions (tons)	PM_{10} Emissions (tons)	PM_{10} 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: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Part 70 Permit No.: T153-45909-00056
Facility: Natural Gas-Fired Combined Cycle Combustion Turbine (CTG-01)
Parameter: $PM_{2.5}$ emissions
Limit: The $PM_{2.5}$ emissions from the combined startup and shutdown events from the Natural Gas-Fired Combined Cycle Combustion Turbine (CTG-01) shall not exceed 1.9 tons per twelve (12) consecutive month period.

QUARTER:____________________ YEAR:____________________

Month	Column 1	Column 2	Column 1 + Column 2
	$PM_{2.5}$ Emissions (tons)	$PM_{2.5}$ Emissions (tons)	$PM_{2.5}$ 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: ____________________

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

Part 70 Quarterly Report

Source Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Part 70 Permit No.: T153-45909-00056
Facility: Natural Gas-Fired Combined Cycle Combustion Turbine (CTG-01)
Parameter: VOC emissions
Limit: The VOC emissions from the combined startup and shutdown events from the Natural Gas-Fired Combined Cycle Combustion Turbine (CTG-01) shall not exceed 18.8 tons per twelve (12) consecutive month period.

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:______________________________

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

Part 70 Quarterly Report

Source Name:	Maple Creek Energy LLC
Source Address:	W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Part 70 Permit No.:	T153-45909-00056
Facility:	Natural Gas-Fired Combined Cycle Combustion Turbine (CTG-01)
Parameter:	CO_2e emissions
Limit:	The CO_2e emissions from the Natural Gas-Fired Combined Cycle Combustion Turbine (CTG) shall not exceed 2,065,094 tons per twelve (12) consecutive month period.

QUARTER:____________________ YEAR:____________________

Month	Column 1	Column 2	Column 1 + Column 2
	CO_2e Emissions (tons)	CO_2e Emissions (tons)	CO_2e 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: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Part 70 Permit No.: T153-45909-00056
Facility: Auxiliary Boiler (AUX)
Parameter: CO2e emissions
Limit: The CO2e emissions from the auxiliary boiler (AUX) shall not exceed 11,244 tons per twelve (12) consecutive month period.

QUARTER:____________________ YEAR:____________________

Month	Column 1	Column 2	Column 1 + Column 2
	CO_2e Emissions (tons)	CO_2e Emissions (tons)	CO_2e 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: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Part 70 Permit No.: T153-45909-00056
Facility: Auxiliary Boiler (AUX)
Parameter: Hours of Operation
Limit: The natural gas-fired auxiliary boiler (AUX) shall not exceed 2,000 hours of operation per twelve (12) consecutive month period.

QUARTER:____________________ YEAR:____________________

Month	Column 1	Column 2	Column 1 + Column 2
	Hours of Operation (hours)	Hours of Operation (hours)	Hours of Operation (hours)
	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: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Part 70 Permit No.: T153-45909-00056
Facility: Diesel-fired Emergency Generator (EG)
Parameter: CO2e emissions
Limit: The CO2e emission from the emergency generator shall not exceed 125 tons per twelve (12) consecutive month period.

QUARTER:____________________ YEAR:____________________

Month	Column 1	Column 2	Column 1 + Column 2
	CO_2e Emissions (tons)	CO_2e Emissions (tons)	CO_2e 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:	Maple Creek Energy LLC
Source Address:	W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Part 70 Permit No.:	T153-45909-00056
Facility:	Emergency fire pump (FP)
Parameter:	CO2e emissions
Limit:	The CO_2e emissions from the emergency fire pump (FP) shall not exceed 24 tons per twelve (12) consecutive month period.

QUARTER:____________________ YEAR:____________________

Month	Column 1	Column 2	Column 1 + Column 2
	CO_2e Emissions (tons)	CO_2e Emissions (tons)	CO_2e 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: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Part 70 Permit No.: T153-45909-00056
Facility: Emergency Generator (EG)
Parameter: Hours of Operation
Limit: The emergency generator (EG) shall not exceed 100 hours of operation per twelve (12) consecutive month period.

QUARTER:____________________ YEAR:____________________

Month	Column 1	Column 2	Column 1 + Column 2
	Hours of Operation (hrs)	Hours of Operation (hrs)	Hours of Operation (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: ____

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

Part 70 Quarterly Report

Source Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Part 70 Permit No.: T153-45909-00056
Facility: Diesel-fired Emergency Fire Pump Engine (FP)
Parameter: Hours of Operation
Limit: The emergency fire pump engine (FP) shall not exceed 100 hours of operation per twelve (12) consecutive month period.

QUARTER:____________________ YEAR:____________________

Month	Column 1	Column 2	Column 1 + Column 2
	Hours of Operation (hrs)	Hours of Operation (hrs)	Hours of Operation (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: ____

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: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Part 70 Permit No.: T153-45909-00056

Months: ___________ to ____________ Year: ______________

Page 1 of 2

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: ____

Mail to: Permit Administration and Support Section
Office of Air Quality
Indiana Government Center North
100 North Senate Avenue, Room 13W
Indianapolis, Indiana 46204-2251

Maple Creek Energy LLC
W CR 1040 N .5 MI S & SR 63 .4 MI W
Fairbanks, Indiana

Affidavit of Construction

I, ____, being duly sworn upon my oath, depose and say:
(Name of the Authorized Representative)

1. I live in __________________________ County, Indiana and being of sound mind and over twenty-one (21) years of age, I am competent to give this affidavit.

2. I hold the position of ___________________________ for ___________________________________.
(Title) (Company Name)

3. By virtue of my position with ____, I have personal
(Company Name)
knowledge of the representations contained in this affidavit and am authorized to make these representations on behalf of ____.
(Company Name)

4. I hereby certify that Maple Creek Energy LLC, W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana, completed construction of the Combined-cycle electric generating facility on ____________________ in conformity with the requirements and intent of the construction permit application received by the Office of Air Quality on ***October 6, 2022*** as revised by the application submitted on September 5, 2025 as permitted pursuant to Part 70 Significant Source Modification No. 153-49550-00056 , Plant ID No. 153-00056 issued on ____________________.

5. **Permittee, please cross out the following statement if it does not apply:** Additional (operations/facilities) were constructed/substituted as described in the attachment to this document and were not made in accordance with the construction permit.

Further Affiant said not.

I affirm under penalties of perjury that the representations contained in this affidavit are true, to the best of my information and belief.

Signature____________________________________
Date____

STATE OF INDIANA)
)SS

COUNTY OF ___________________)

Subscribed and sworn to me, a notary public in and for ______________________ County and State of Indiana

on this ______________ day of _______________, 20_____. My Commission expires: ______________________.

Signature__________________________
Name_______________________ (typed or printed)

If the source location has been given an Enhanced 911 service address that is different than the source location address specified in the current permit, please provide the Enhanced 911 service address in the space below and please submit a permit application to modify the permit to specify the Enhanced 911 service address. _________________________ _______________ _____ ______ *(Location* Address*)* *(City)* *(State)* *(ZIP Code)*

Attachment D

Part 70 Operating Permit No: T153-45909-00056

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Source:89 FR 40035, May 9, 2024, unless otherwise noted.

Applicability

§ 60.5508a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a coal-fired steam generating unit or integrated gasification combined cycle facility (IGCC) that commences modification after May 23, 2023. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction or reconstruction after May 23, 2023. An affected coal-fired steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

§ 60.5509a Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit or IGCC that combusts coal and that commences modification after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (8) of this section.

(1) Your EGU is a steam generating unit or IGCC whose annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

Emission Standards

§ 60.5515a Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) PSD and Title V thresholds for greenhouse gases.

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 71.2.

§ 60.5520a What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in table 1 to this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross or net energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross or net energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term "gross or net energy output" is used, the term that applies to you is "gross energy output."

(c) As an alternative to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term "gross or net energy output" is used, the term that applies to you is "net energy output." Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in table 1 to this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in table 1 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel, kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less (e.g., non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

§ 60.5525a What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See table 1 to this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520a(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas (HTIPng) and the total heat input from all other fuels combined (HTIPo) using one of the methods under § 60.5535a(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

Equation 1 to Paragraph (a)(2)

$$CO_2\ emissions\ standard\ = \frac{\left(50 \text{ x } HTIP_{ng}\right) + (69 \text{ x } HTIP_O)}{HTIP_{ng} + HTIP_O}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

$HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas.

$HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in lb kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu).

69 = allowable emission rate in lb kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu).

(3) Owners/operators of a base load combustion turbine with a base load rating of less than 2,110 GJ/h (2,000 MMBtu/h) and/or an intermediate or base load combustion turbine burning fuels other than natural gas may elect to determine a site-specific emissions rate using one of the following equations. Combustion turbines co-firing hydrogen are not required to use the fuel adjustment parameter.

(i) For base load combustion turbines:

Equation 2 to Paragraph (a)(3)(i)

$$CO_2\ emissions\ standard\ = \left[BLER_L + \frac{BLER_S - BLER_L}{\mathrm{BLR}_L - \mathrm{BLR}_S} * (\mathrm{BLR}_L - BLR_A)\right] * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

$BLER_L$ = Base load emissions standard for natural gas-fired combustion turbines with base load ratings greater than 2,110 GJ/h (2,000 MMBtu/h). 360 kg CO_2/MWh-gross (800 lb CO_2/MWh-gross) or 370 kg CO_2/MWh-net (820 lb CO_2/MWh-net); 43 kg CO_2/MWh-gross (100 lb CO_2/MWh-gross) or 42 kg CO_2/MWh-net (97 lb CO_2/MWh-net); as applicable

$BLER_S$ = Base load emissions standard for natural gas-fired combustion turbines with a base load rating of 260 GJ/h (250 MMBtu/h). 410 kg CO_2/MWh-gross (900 lb CO_2/MWh-gross) or 420 kg CO_2/MWh-net (920 lb CO_2/MWh-net); 49 kg CO_2/MWh-gross (108 lb CO_2/MWh-gross) or 50 kg CO_2/MWh-net (110 lb CO_2/MWh-net); as applicable

BLR_L = Minimum base load rating of large combustion turbines 2,110 GJ/h (2,000 MMBtu/h)

BLR_S = Base load rating of smallest combustion turbine 260 GJ/h (250 MMBtu/h)

BLR_A = Base load rating of the actual combustion turbine in GJ/h (or MMBtu/h)

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(ii) For intermediate load combustion turbines:

Equation 3 to Paragraph (a)(3)(ii)

$$CO_2\ emissions\ standard\ = \mathrm{ILER} * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

ILER = Intermediate load emissions rate for natural gas-fired combustion turbines. 520 kg/MWh-gross (1,150 lb CO_2/MWh-gross) or 530 kg CO_2/MWh-net (1,160 lb CO_2/MWh-net) or 450 kg/MWh-gross (1,100 lb CO_2/MWh-gross) or 460 kg CO_2/MWh-net (1,110 lb CO_2/MWh-net) as applicable

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.,* no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in table 1 to this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in 40 CFR 72.2), the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555a(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555a(c)(3)(ii), for units that are not in the Acid Rain Program.

(2) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under § 60.5555a(c)(3)(iii).

(3) Emissions of CO_2 emitted by your affected facility and the output of the affected facility generated when it operated during a system emergency as defined in § 60.5580a are excluded for both applicability and compliance with the relevant standards of performance if you can sufficiently provide the documentation listed in § 60.5560a(i). The relevant standard of performance for affected EGUs that operate during a system emergency depends on the subcategory, as described in paragraphs (c)(3)(i) and (ii) of this section.

(i) For intermediate and base load combustion turbines that operate during a system emergency, you comply with the standard for low load combustion turbines specified in table 1 to this subpart.

(ii) For modified steam generating units, you must not discharge from the affected EGU any gases that contain CO_2 in excess of 230 lb CO_2/MMBtu.

Monitoring and Compliance Determination Procedures

§ 60.5535a How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520a(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555a(d) and (e)).

(b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected EGU that combusts coal you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.,* carbon capture and storage), you may use data from a certified oxygen (O2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, you may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part 75.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR part 75 to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with 40 CFR part 75. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for "valid operating hours", as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F-11 in appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 907.2 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in § 60.5520a(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to 40 CFR part 75 to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G-4 in appendix G to 40 CFR part 75 to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (Fc) using Equation F-7b in section 3.3.6 of appendix F to 40 CFR part 75, and you may use these Fc values in the emissions calculations instead of using the default Fc values in the Equation G-4 nomenclature.

(3) For each "valid operating hour" (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Then, multiply the result by 907.2 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under § 60.107a(d) and convert this heat input to CO_2 emissions using Equation G-4 in appendix G to 40 CFR part 75.

(ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under 40 CFR 98.33(a)(3).

(d) Consistent with § 60.5520a, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.,* lb CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20-2010 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580a, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.,* hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.,* lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under § 60.5520a(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to 40 CFR part 75;

(ii) The procedures for monitoring heat input under § 60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under 40 CFR 98.33(a)(3), you may convert your CO_2 emissions to heat input using the appropriate emission factor in table C-1 of 40 CFR part 98. If your fuel is not listed in table C-1, you must determine a fuel-specific carbon-based F-factor (Fc) in accordance with section 12.3.2 of EPA Method 19 of appendix A-7 to this part, and you must convert your CO_2 emissions to heat input using Equation G-4 in appendix G to 40 CFR part 75.

(e) Consistent with § 60.5520a, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross or net energy output. The Administrator may approve such alternate methods for apportioning the gross or net energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§ 60.13(g) and 60.5520a, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in table 1 to this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as “stack operating hours” (as defined in 40 CFR 72.2). If you attain compliance with the applicable emissions standard in § 60.5520a at the common stack, each affected EGU sharing the stack is in compliance; or

(2) As an alternative to the requirements in paragraph (f)(1) of this section, or if the EGUs are subject to different emission standards in table 1 to this subpart, you must either:

(i) Monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or

(ii) Apportion the CO_2 mass emissions based on the unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(g) In accordance with §§ 60.13(g) and 60.5520a if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the “stack operating time” (as defined in 40 CFR 72.2) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in table 1 or 2 to this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§ 60.5540a How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520a, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520a(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in table 1 to this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (8) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.,* either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under § 60.5535a(b) or (c), as applicable, and either the generating load data from § 60.5535a(d)(1) for output-based calculations or the heat input data from § 60.5535a(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.,* blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only “valid operating hours” in the compliance period, *i.e.,* operating hours for which:

(i) “Valid data” (as defined in § 60.5580a) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (Note: For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535a for all of the valid operating hours in the compliance period.

(5) For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(5)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with § 60.5520a) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to Paragraph (a)(5)(i)

$$P_{gross/net} = \frac{(Pe)_{ST}+(Pe)_{CT}+(Pe)_{IE}-(Pe)_{FW}-(Pe)_{A}}{TDF} + [\ (Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}\ ] \ \text{(Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520a, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540a(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate (Pt)PS using the following equation:

Equation 2 to Paragraph (a)(5)(ii) $$(Pt)_{PS} = \frac{Q_m \times H}{CF} \text{ (Eq. 3)}$$

Where:

Q_m = Measured useful thermal output flow in kg (lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) Sources complying with energy output-based standards must calculate the basis (*i.e.,* denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520a if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(8) You may exclude CO_2 mass emissions and output generated from your affected EGU from your calculations for hours during which the affected EGU operated during a system emergency, as defined in § 60.5580a, if you can provide the information listed in § 60.5560a(i). While operating during a system emergency, your compliance determination depends on your subcategory or unit type, as listed in paragraphs (a)(8)(i) through (ii) of this section.

(i) For affected EGUs in the intermediate or base load subcategory, your CO_2 emission standard while operating during a system emergency is the applicable emission standard for low load combustion turbines.

(ii) For affected modified steam generating units, your CO_2 emission standard while operating during a system emergency is 230 lb CO_2/MMBtu.

(b) In accordance with § 60.5520a, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (8) of this section and must be less than or equal to the applicable CO_2 emissions standard in table 1 to this subpart, or the emissions standard calculated in accordance with § 60.5525a(a)(2).

(c) If you are the owner or operator of a new or reconstructed stationary combustion turbine operating in the base load subcategory, are installing add-on controls, and are unable to comply with the applicable Phase 2 CO_2 emission standard specified in table 1 to this subpart due to circumstances beyond your control, you may request a compliance date extension of no longer than one year beyond the effective date of January 1, 2032, and may only receive an extension once. The extension request must contain a demonstration of necessity that includes the following:

(1) A demonstration that your affected EGU cannot meet its compliance date due to circumstances beyond your control and you have taken all steps reasonably possible to install the controls necessary for compliance by the effective date up to the point of the delay. The demonstration shall:

(i) Identify each affected unit for which you are seeking the compliance extension;

(ii) Identify and describe the controls to be installed at each affected unit to comply with the applicable CO_2 emission standard in table 1 to this subpart;

(iii) Describe and demonstrate all progress towards installing the controls and that you have acted consistently with achieving timely compliance, including;

(A) Any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable;

(B) Any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permit authority identifying its anticipated timeframe for issuance of such permit(s).

(iv) Identify the circumstances that are entirely beyond your control and that necessitate additional time to install the identified controls. This may include:

(A) Information gathered from control technology vendors or engineering firms demonstrating that the necessary controls cannot be installed or started up by the applicable compliance date listed in table 1 to this subpart;

(B) Documentation of any permit delays; or

(C) Documentation of delays in construction or permitting of infrastructure (*e.g.,* CO_2 pipelines) that is necessary for implementation of the control technology;

(v) Identify a proposed compliance date no later than one year after the applicable compliance date listed in table 1 to this subpart.

(2) The Administrator is charged with approving or disapproving a compliance date extension request based on his or her written determination that your affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation according to paragraph (c)(1) of this section. The following must be included:

(i) All documentation required as part of this extension must be submitted by you to the Administrator no later than 6 months prior to the applicable effective date for your affected EGU.

(ii) You must notify the Administrator of the compliance date extension request at the time of the submission of the request.

Notification, Reports, and Records

§ 60.5550a What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see table 3 to this subpart).

(b) You must prepare and submit notifications specified in 40 CFR 75.61, as applicable, to your affected EGUs.

§ 60.5555a What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by § 60.5525a to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in § 60.5540a. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1) of this section (*i.e.,* the total number of valid operating hours (as defined in § 60.5540a(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520a, the CO_2 emissions standard (as identified in table 1 or 2 to this subpart) with which your affected EGU must comply; and

(vi) Consistent with § 60.5520a, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with § 60.5520a, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)

(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)

(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with 40 CFR 75.64(a), *i.e.,* beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in 40 CFR 75.20(a)(3); or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in 40 CFR 72.2).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after the date on which reporting is required to begin under 40 CFR 75.64(a), if that date occurs on or after May 23, 2023.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with 40 CFR 75.4(j), 40 CFR 75.37(b), or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not “valid operating hours” (as defined in § 60.5540(a)(1)), and shall not be used in the compliance determinations under § 60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under 40 CFR 72.20; or

(2) The person appointed as the Alternate Designated Representative (ADR) under 40 CFR 72.22; or

(3) A person (or persons) authorized by the DR or ADR under 40 CFR 72.26 to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission standard, you must report in accordance with the requirements of 40 CFR part 98, subpart PP, and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured CO_2 to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§ 60.5560a What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in § 60.7(b) and (f).

(b)

(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under 40 CFR 75.53(g) and (h);

(ii) Operating parameter records under 40 CFR 75.57(b)(1) through (4);

(iii) The records under 40 CFR 75.57(c)(2), for stack gas volumetric flow rate;

(iv) The records under 40 CFR 75.57(c)(3) for continuous moisture monitoring systems;

(v) The records under 40 CFR 75.57(e)(1), except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O2 monitors used to calculate CO_2 concentration;

(vi) The records under 40 CFR 75.58(c)(1), specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under 40 CFR 75.58(c)(4), specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under 40 CFR 75.59(e).

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with § 60.5520a, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in table 1 or 2 to this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

(i) You must keep the records listed in paragraphs (i)(1) through (3) of this section to demonstrate that your affected facility operated during a system emergency.

(1) Documentation that the system emergency to which the affected EGU was responding was in effect from the entity issuing the alert and documentation of the exact duration of the system emergency;

(2) Documentation from the entity issuing the alert that the system emergency included the affected source/region where the affected facility was located; and

(3) Documentation that the affected facility was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/Regional Transmission Organization.

§ 60.5565a 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.

(b) You must maintain each record for 5 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

Other Requirements and Information

§ 60.5570a What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§ 60.1 through 60.19, listed in table 3 to this subpart, do not apply to your affected EGU.

§ 60.5575a Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or Tribal agency. If the 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, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or Tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

§ 60.5580a 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.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.,* solar thermal) are not included when calculating the annual capacity factor.

Base load combustion turbine means a stationary combustion turbine that supplies more than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.,* solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite in ASTM D388-99R04 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired Electric Generating Unit means a steam generating unit or integrated gasification combined cycle unit that combusts coal on or after the date of modification or at any point after December 31, 2029.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit,* (also known as “cogeneration”) means an electric generating unit that simultaneously produces both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a higher heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22-2014, ASME PTC 46-1996, ISO 2314:2009 (E) (all incorporated by reference, see § 60.17), or an alternative approved by the Administrator. When determining the design efficiency, the output of integrated equipment and energy storage are included.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined in ASTM D396-98 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined in ASTM D975-08a (incorporated by reference, see § 60.17); kerosene, as defined in ASTM D3699-08 (incorporated by reference, see § 60.17); biodiesel as defined in ASTM D6751-11b (incorporated by reference, see § 60.17); or biodiesel blends as defined in ASTM D7467-10 (incorporated by reference, see § 60.17).

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (*i.e.,* meets the applicability criteria).

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas, plus any integrated equipment that provides electricity or useful thermal output to the affected EGU or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

Intermediate load combustion turbine means a stationary combustion turbine that supplies more than 20 percent but less than or equal to 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Low load combustion turbine means a stationary combustion turbine that supplies 20 percent or less of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has 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), that maintains a gaseous state under ISO conditions. Finally, 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 CO_2 content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating month basis, the gross electric sales to the utility power distribution system minus the applicable percentage of purchased power of the thermal host facility or facilities. The applicable percentage of purchase power for CHP facilities is determined based on the percentage of the total thermal load of the host facility supplied to the host facility by the CHP facility. For example, if a CHP facility serves 50 percent of a thermal host's thermal demand, the owner/operator of the CHP facility would subtract 50 percent of the thermal host's electric purchased power when calculating net-electric sales.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales during a system emergency are not included when calculating net-electric sales.

Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means the base load rating design efficiency at the maximum electric production rate (*e.g.,* CHP units with condensing steam turbines will operate at maximum electric production) multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.,* a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, (*e.g.,* onsite photovoltaics), integrated energy storage (*e.g.,* onsite batteries), heat recovery system, or auxiliary equipment. 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. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment.

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP-011-2 or its successor.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in 40 CFR 75.20 and appendix A to 40 CFR part 75 must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to 40 CFR part 75 must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to 40 CFR part 75. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to 40 CFR part 75 must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to 40 CFR part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to 40 CFR part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in table 1 to this subpart.

Table 1 to Subpart TTTTa of Part 60—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)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU category	CO_2 emission standard
Base load combustion turbines	For 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
	For 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Intermediate load combustion turbines	530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 700 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Low load combustion turbines	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525a.

Table 2 to Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Steam Generating Units or IGCC That Commenced Modification After May 23, 2023

Affected EGU	CO_2 Emission standard
Modified coal-fired steam generating unit	A unit-specific emissions standard determined by an 88.4 percent reduction in the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification).

Table 3 to Subpart TTTTa of Part 60—Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTTa

General provisions citation	Subject of citation	Applies to subpart TTTTa	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580a.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	No.	
§ 60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods.
§ 60.8(c)-(f)	Conducting performance tests	No.	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13 (a)-(h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§ 60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements.

General provisions citation	**Subject of citation**	**Applies to subpart TTTTa**	**Explanation**
§ 60.14	Modification	Yes (steam generating units and IGCC facilities) No (stationary combustion turbines).	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the Technical Support Document (ATSD) for a Part 70 Significant Permit Modification and PSD/Significant Source Modification

Source Background and Description

Source Name:	**Maple Creek Energy LLC**
Source Location:	**W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849**
County:	**Sullivan**
SIC Code:	**4911 (Electric Services)**
Operation Permit No.:	**T153-45909-00056**
Operation Permit Issuance Date:	**June 19, 2023**
Significant Source Modification No.:	**153-49550-00056**
Significant Permit Modification No.:	**153-50217-00056**
Permit Reviewer:	**Tamera Wessel**

On April 2, 2026, the Office of Air Quality (OAQ) had a notice posted on IDEM's website (https://www.in.gov/idem/public-notices/), stating that Maple Creek Energy LLC had applied for a Part 70 significant permit modification and PSD/significant source modification to remove the Siemens Model SCC6-9000HL Turbine option from the permit and to adjust potential emissions calculations for the remaining turbine due to updated emissions data provided by the turbine manufacturer. The notice also stated that the OAQ proposed to issue a Part 70 significant permit modification and PSD/significant source modification for this operation and provided information on how the public could review the proposed permit and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit should be issued as proposed.

Comments and Responses

On April 22, 2026, Maple Creek Energy LLC, submitted comments to IDEM, OAQ on the draft Part 70 significant permit modification and PSD/significant source modification.

The Technical Support Document (TSD) is used by IDEM, OAQ for historical purposes. IDEM, OAQ does not make any changes to the original TSD, but the Permit will have the updated changes. The comments and revised permit language are provided below with deleted language as ~~strikeouts~~ and new language **bolded**.

Comment 1:

> Condition D.1.8 Startup and Shutdown contains information not pertinent to the startup and shutdown information contained in Condition D.1.8. Please remove.

Response to Comment 1:

> IDEM agrees with the recommended changes, since the condition includes statements not relevant to the topic of startup and shutdown. The permit has been revised as follows:
>
> *****

D.1.8 Startup and Shutdown

~~Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbine shall be as follows:~~

(a) A startup is defined as the operation in the period beginning when continuous fuel flow to the combustion turbine is initiated and ending when the CCCT achieves steady-state operating condition:
*****

Comment 2:

To provide clarity for reporting requirements, replace "information" with the specific items to be reported in Conditions D.1.14 Reporting Requirements and D.2.8 Reporting Requirements.

Response to Comment 2:

IDEM agrees with the recommended changes, since additional information will eliminate any confusion as to what reporting is needed to remain compliant. The permit has been revised as follows:

****

D.1.14 Reporting Requirements

(a) A quarterly summary of ~~the information~~**PM, PM_{10}, $PM_{2.5}$, NOx, VOC, and CO emissions** to document the compliance status with D.1.2 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.

*****

D.2.8 Reporting Requirements

A quarterly report of monthly CO_{2e} emissions and hours of operation **of the auxiliary boiler (AUX)** ~~and a quarterly summary of the information~~ to document the compliance status with D.2.1(l) and D.2.1(n) 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.

*****

Comment 3:

The condition citation in condition D.2.5 Greenhouse Gases (GHGs) Calculations references the wrong citation.

Response to Comment 3:

IDEM agrees with the recommended changes, since the citation refers to the wrong item. The permit has been revised as follows:

D.2.5 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with condition D.2.1(~~n~~**l**), the following equation shall be used to determine the CO_{2e} emissions from the Auxiliary Boiler:

Comment 4:

Condition D.2.6 contains typographical errors that need to be corrected.

Response to Comment 4:

IDEM agrees with the recommended changes. The permit has been revised as follows:

*****

D.2.6 Testing Requirements [326 IAC 2-1.1-11]

*****

(c) In order to demonstrate compliance with Condition D.2.1(h), within 60 days after achieving the maximum production rate of the emission unit, but not later than 180 days after the startup of natural gas-fired auxiliary boiler, the Permittee shall perform CO testing of the natural gas-fired auxiliary boiler utilizing methods approved by the commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

(~~e~~**d**) In order to demonstrate compliance with Condition D.2.1(j), within 60 days after achieving the maximum production rate of the emission unit, but not later than 180 days after the startup of natural gas-fired auxiliary boiler, the Permittee shall perform H_2SO_4 testing of the natural gas-fired auxiliary boiler utilizing methods approved by the commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

(~~f~~**e**) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition. PM_{10} and $PM_{2.5}$ includes filterable and condensable PM.

*****

Additional Changes

IDEM, OAQ has decided to make additional revisions to the permit as described below, with deleted language as ~~strikeouts~~ and new language **bolded**.

(a) IDEM, OAQ has updated Condition D.1.1(f) to include good combustion practices as part of NOx control.

(b) IDEM, OAQ has included a specific value, per AP-42, for the heat content to use in the CO2e emissions calculation in Condition D.1.7 for clarity.

(c) IDEM, OAQ has updated rule citations pertaining to the definition of responsible official in Conditions D.2.8 and D.3.6.

(d) IDEM, OAQ has included compliance equations for PM, PM10, PM2.5, and VOC emissions to assist in demonstrating compliance with Condition D.1.2.

(e) IDEM, OAQ has updated the links within Conditions F.10(b), F.10(c), F.10(d). The EPA's Air Markets program has been updated to be named Clean Air Power Sector Programs and the links to petitions have been updated accordingly.

(f) IDEM, OAQ has revised the initial testing timeframe requirement for H_2SO_4 in Condition D.1.10(c) to provide consistency between Maple Creek I and Maple Creek II testing requirements.

IDEM, OAQ has decided to make additional revisions to the emission calculations (See ATSD Appendix A: Emission Calculations) and to the permit as described below, with deleted language as ~~strikeouts~~ and new language **bolded**.

(a) IDEM, OAQ has added startup/shutdown pounds per hour, in order to determine emissions for compliance determination.

IDEM, OAQ has decided to make additional revisions to Appendix B to the permit as described below, with deleted language as ~~strikeouts~~ and new language **bolded**.

(a) IDEM, OAQ has corrected the Summary of RBLC Database Review - Large Combustion Turbines - Natural Gas - VOC by removing Selective Catalytic Reduction (SCR) as the listed control method for Alabama Power (RBLC ID: AL-0328) and FG LA Complex (RBLC ID: LA-0364). These control methods were inadvertently included in the summary table but are not found in a search of the RBLC for these facilities. A note has been included to explain the inclusion of SCR for Renovo Energy Center LLC / Renovo PLT (RBLC ID: PA-0334).

(b) IDEM, OAQ has removed the 3-hour average specification for SO_2 emissions from the H_2SO_4 BACT determination for CTG-01 in Appendix B: Best Available Control Technology (BACT) Analysis Determination. This requirement is intended for emission units using continuous emissions monitors (CEMS) to monitor the pollutant in question.

(c) IDEM, OAQ has updated the PM/PM10/PM2.5 BACT Determination: Combined-Cycle Gas Turbine, Step 4: Evaluate Top Control Alternatives within Appendix B for clarity.

(d) IDEM, OAQ has updated the NOx BACT Determination: Combined-Cycle Gas Turbine, to include good combustion practices.

(e) IDEM, OAQ has removed the 3-hour average specification for CO emissions from the CO BACT determination for auxiliary boilers in Appendix B: Best Available Control Technology (BACT) Analysis Determination. This requirement is intended for emission units using continuous emissions monitors (CEMS) to monitor the pollutant in question.

(f) IDEM, OAQ has corrected a typographical error in the NOx RBLC Database Review tables for the Auxiliary Boilers in Appendix B. The RBLC entry for WV-0029 should indicate a NOx emission limit of 0.011 lb/MMBtu, not 0.0011 lb/MMBtu.

(g) IDEM, OAQ has added further explanation to the evaluation of BACT for PM, PM10, and PM2.5 from the diesel-fired emergency generator (EG-02) to explain why Hybar (RBLC ID: AR-0191) established a PM, PM10, and PM2.5 BACT that is more stringent than the emission limits established in 40 CFR 60, Subpart IIII.

****

D.1.1 PSD and VOC BACT [326 IAC 2-2-3] [326 IAC 8-1-6]

*****

(f) The NOx emissions from CTG-01 shall be controlled by a Selective Catalytic Reduction system ~~and~~**,** dry-low-NOx combustors**, and good combustion practices**.

*****

D.1.7 Greenhouse Gases (GHGs) Calculations

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Heat Content (mmbtu/mmscf) = standard value in AP-42 for natural gas **(1,020 mmBtu/mmscf)** or vendor data, if available

*****

D.1.8 Startup and Shutdown

(a) **To determine the compliance status with Condition D.1.2(a), the following equation shall be used to determine the PM, PM10, and PM2.5 emissions from the startup and shutdown events from CTG-01:**

$PM/PM_{10}/PM_{2.5}$ (tons/month) = [SU_C (hrs/month) x EFc (lb/hr) + SU_W (hrs/month) x EFw (lb/hr) + SU_H (hrs/month) x EF_H (lb/hr) + SD (hrs/month) x EF_{SD} (lb/hr)] x 1/2000 (ton/lb)

Where:

SUc =	**Hours of cold startup per month**
EFc (lb/hr) =	**$PM/PM_{10}/PM_{2.5}$ emissions per hour of cold startup (13.5 pounds per hour per vendor provided data)**
SUw =	**Hours of warm startup per month**
EF_W (lb/hr) =	**$PM/PM_{10}/PM_{2.5}$ emissions per hour of warm startup (13.5 pounds per hour per vendor provided data)**
SU_H =	**Hours of hot startup per month**
EF_H (lb/hr) =	**$PM/PM_{10}/PM_{2.5}$ emissions per hour of hot startup (13.6 pounds per hour per vendor provided data)**
SU_{SD} =	**Hours of shutdown per month**
EF_{SD} (lb/hr) =	**$PM/PM_{10}/PM_{2.5}$ emissions per hour of shutdown (12.5 pounds per hour per vendor provided data)**

(b) **To determine the compliance status with Condition D.1.2(c), the following equation shall be used to determine the VOC emissions from the startup and shutdown events from CTG-01:**

VOC (tons/month) = [SU_C (hr/month) x EFc (lb/hr) + SU_W (hr/month) x EFw (lb/hr) + SU_H (hr/month) x EF_H (lb/hr) + SD (hr/month) x EF_{SD} (lb/hr)] x 1/2000 (ton/lb)

Where:

SUc =	**Hours of cold startup per month**
EFc (lb/hr) =	**VOC emissions per hour of cold startup (85.7 pounds per hour per vendor provided data)**
SUw =	**Hours of warm startup per month**
EF_W (lb/hr) =	**VOC emissions per hour of warm startup (85 pounds per hour per vendor provided data)**
SU_H =	**Hours of hot startup per month**
EF_H (lb/hr) =	**VOC emissions per hour of hot startup (160 pounds per hour per vendor provided data)**
SU_{SD} =	**Hours of shutdown per month**
EF_{SD} (lb/hr) =	**VOC emissions per hour of shutdown (300 pounds per hour per vendor provided data)**

(~~a~~**c**) A startup is defined as the operation in the period beginning when continuous fuel flow to the combustion turbine is initiated and ending when the CCCT achieves steady-state operating condition:

*****

D.1.10 Testing Requirements [326 IAC 2-1.1-11]

*****

(c) In order to demonstrate compliance with Conditions D.1.1(q), **within 60 days after achieving the maximum production rate of the emission unit, but** not later than 180 days after initial start-up, the Permittee shall perform H_2SO_4 testing on CTG-01, utilizing methods as approved by the Commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

D.2.8 Reporting Requirements

A quarterly report of monthly CO_{2e} emissions and hours of operation of the auxiliary boiler (AUX) to document the compliance status with D.2.1(l) and D.2.1(n) 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~~**33**).

*****

D.3.6 Reporting Requirements

A quarterly report of monthly CO_{2e} emissions and hours of operation and a quarterly summary of the information to document the compliance status with D.3.1(e)(2) and D.3.1(f)(2), 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)~~**(33)**.

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F.10 Description of CSAPR Monitoring Provisions

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(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~~**https://www.epa.gov/amtic/regulations-guidance-and-monitoring-plans**.

(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), 97.835 (CSAPR NO_X Ozone Season Group 2 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 **https://www.epa.gov/petitions**~~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), 97.830 through 97.834 (CSAPR NO_X Ozone Season Group 2 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), 97.835 (CSAPR NO_X Ozone Season Group 2 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 **https://www.epa.gov/petitions**~~http://www.epa.gov/airmarkets/emissions/petitions.html~~.

*****

Appendix B has been revised as follows:

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Summary of RBLC Database Review - Large Combustion Turbines - Natural Gas - VOC

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
*****	****	****	****	****
Renovo Energy Center LLC / Renovo PLT	18-00033B (04/29/2021)	PA-0334	Combustion Turbines with Duct Burners #1 and #2 (4546 MMBtu/hr, each)	Control Method: SCR* and catalytic oxidizer VOC Emission Limits: 1.6 ppmdv at 15% O2 9.3 lb/hr (*no lb/MMBtu listed)*
Alabama Power Company	503-1001 (11/09/2020)	AL-0328	(2) Combined Cycle Units (744 MW)	Control Method: ~~SCR and~~ Oxidation Catalyst VOC Emission Limits: 13.6 lb/hr 0.003 lb/MMBtu
FG LA Complex	PSD-LA-812 (01/06/2020)	LA-0364	Natural Gas Cogeneration Units (2222 MMBtu/hr)	Control Method: ~~SCR~~ Good combustion practices and catalytic oxidation VOC Emission Limit: 4.0 ppmvd @ 15% O_2 (*no lb/MMBtu listed)*
****	****	****	****	****

* **The P2/Add-on Description field for all pollutants of Renovo Energy Center LLC / Renovo PLT include "SCR, Catalytic Oxidizer." It appears that SCR and Catalytic Oxidizer were the default entry for this field for the entire RBLC entry, and does not really indicate that SCR was used for VOC control.**

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Step 5: Select BACT (H_2SO_4)

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the CTG shall be as follows:

(1) SO_2 and H_2SO_4 from CTG-01 shall be controlled through the use of pipeline-quality natural gas.

(2) SO_2 emissions from CTG-01 shall not exceed 0.0019 lb/MMBtu~~, based on a 3-hour average~~.

*****

MCE ~~II~~ **I**'s proposed $PM/PM_{10}/PM_{2.5}$ limit of 0.0058 lb/MMBtu for GE technology is based on the vendor estimate and is on the lower end of the range of the other $PM/PM_{10}/PM_{2.5}$ BACT limits for GE turbines presented in the above table and is generally consistent with the Duke Energy project. MCE ~~II~~ **I**'s proposed $PM/PM_{10}/PM_{2.5}$ limit is more stringent than the **existing** MCE I facility (0.0075 lb/MMBtu) due to a reduction in vendor emissions estimates.

*****

Summary of RBLC Database Review - Large Combustion Turbines - Natural Gas

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Requirements
Maple Creek Energy I LLC	Proposed	--	Combined Cycle Combustion Turbine Generator (4,200 MMBtu/hr)	Control Method: Selective Catalytic Reduction system and dry-low NOx combustors**, good combustion practices** NO_X Emission Limits: 2.0 ppmvdc, excluding SU/SD @ 15% O_2 based on a 3-hour average 30.9 lb/hr, excluding SU/SD NOx SU/SD Emission Limit: 35.8 tons/yr for duration of combined SU/SD Events
*****	*****	*****	*****	*****

*****

Step Five: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the combustion turbine generator shall be as follows:

(1) The NOx emissions from CTG-01 shall be controlled by a Selective Catalytic Reduction system ~~and~~**,** dry-low-NOx combustors**, and good combustion practices**.

Step 5: Select BACT (CO)

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler (AUX) shall be as follows:

(1) CO emissions from the natural gas-fired auxiliary boiler (AUX) shall not exceed 0.037 lb/MMBtu~~, based on a 3-hour average~~.

*****

Summary of RBLC Database Review - Auxiliary Boilers - Natural Gas

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO Emission Limits
Maple Creek Energy I LLC	Proposed	--	Natural Gas-Fired Auxiliary Boiler (96 MMBtu/hr)	Control Method: Good combustion practices CO Emission Limit: 0.037 lb/MMBtu~~, 3-hr avg.~~

*****

Harrison County Power Plant	R14-0036 (03/27/2018)	WV-0029	Auxiliary Boiler (77.80 MMBtu/hr) (Annual Emissions based on 4,600	Control Method: Low-NOx burners, GCP, FGR NOx Emission Limit: 0.86 lb/hr 1.96 tons/year

			hrs/yr)	~~0.0011~~**0.011** lb/MMBtu

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Summary of RBLC Database Review - Large Internal Combustion Engines - Diesel Fuel

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Hybar (AR-0191) proposes a more stringent $PM/PM_{10}/PM_{2.5}$ emission limit, based on vendor emissions data, of 0.1 g/bhp-hr with good operating practices, limited hours of operation, and compliance with NSPS Subpart IIII. **The emission factors used by the Hybar facility for the emergency diesel-fired generator are from Kohler KD2500 Tier 2 EPA Certified for Stationary Emergency Applications Emission Optimized Data Sheet, EPA D2 Cycle 5-mode weighted emission factors. Hybar has a large number of generators and HAP restrictions associated with the steel mill facility, resulting in a need for reduced emissions.** 40 CFR 60, Subpart IIII establishes a $PM/PM_{10}/PM_{2.5}$ emission limit of 0.15 g/hp-hr for engines with a maximum power of greater than 750 HP.

*****

IDEM Contact

(a) If you have any questions regarding this permit, please contact Tamera Wessel, 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) 234-8530 or (800) 451-6027, and ask for Tamera Wessel.

(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: ATSD Emission Calculations
PTE Summary

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Uncontrolled Potential to Emit (tons/yr)									
Emissions Unit	**PM**	**PM10**	**PM2.5 ***	**SO_2**	**NOx**	**VOC**	**CO**	**H_2SO_4**	**GHGs**
Emission Units Plant 1									
CCGT - Steady State and SU/SD[1]	59.57	59.57	59.57	28.47	136.12	36.14	112.69	19.27	2,065,094
CCGT - SU/SD[2]	5.91	5.91	5.91		113.73	59.64	165.71		
Auxiliary Boiler	3.15	3.15	3.15	0.59	15.55	1.45	15.55	0.059	49,247
Emergency Generator	0.17	0.17	0.17	0.006	5.32	0.35	2.89	negl.	625.26
Fire Pump	0.03	0.03	0.03	0.00	0.69	0.09	0.60	negl.	122.60
Tanks	--	--	--	--	--	0.5	--	--	--
Paved Roads (Fugitive)	*0.37*	*0.07*	*0.02*	--	--	--	--	--	--
Plant 1 Total	**63.30**	**63.00**	**62.94**	**29.07**	**157.68**	**62.03**	**184.76**	**19.33**	**2,115,089**
Plant 2 Total	60.70	60.40	60.35	28.61	140.87	37.06	116.94	19.29	2,076,487.23
Total PTE of Entire Source Including Fugitives	***124.00***	***123.40***	***123.29***	***57.67***	***298.56***	***99.09***	***301.70***	***38.62***	***4,191,576.11***

** PM2.5 listed is direct PM2.5*
***Fugitve HAP emissions are always included in the source-wide emissions*
** PM2.5 listed is direct PM2.5*
1 - Emissions include start up and shut/down operations with steady state operations
2 - Emissions represent startup/shutdown operations for 8,760 hours per year.
****The uncontrolled potential to emit of Plant 2 (Maple Creek Energy LLC) is from T153-49555-00064, pending.*

Appendix A: ATSD Emission Calculations
HAP Summary

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W. Fairbanks. Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Uncontrolled Potential to Emit (tons/yr)

Emissions Unit	1.3 Butadiene	Acenaphthene	Acenaphthylene	Acetaldehyde	Acrolein	Anthracene	Benz(a)-anthracene	Benzene	Benzo(a)-pyrene	Benzo(b)-fluoranthene	Benzo(g,h,i)-perylene	Benzo(k)-fluoranthene
Emission Units Plant 1 CCGT	0.01	--	--	0.70	0.11	--	--	0.21	--	--	--	--
Auxiliary Boiler	--	7.31E-07	7.31E-07	--	--	9.74E-07	7.31E-07	8.52E-04	4.87E-07	7.31E-07	4.87E-07	7.31E-07
Emergency Generator	--	1.67E-05	3.29E-05	8.99E-05	2.81E-05	4.39E-06	2.22E-06	2.77E-03	9.17E-07	3.96E-06	1.98E-06	7.78E-07
Fire Pump	2.91E-05	1.06E-06	3.77E-06	5.71E-04	6.89E-05	1.39E-06	1.25E-06	6.95E-04	1.40E-07	7.38E-08	3.64E-07	1.15E-07
	0.01	0.00	0.00	0.70	0.11	0.00	0.00	0.21	0.00	0.00	0.00	0.00
Plant 2 Total	7.54E-03	3.72E-06	7.51E-06	7.01E-01	1.12E-01	1.38E-06	8.61E-07	2.11E-01	3.23E-07	9.74E-07	5.81E-07	3.45E-07
Source Total	1.51E-02	2.22E-05	4.49E-05	1.40E+00	2.24E-01	8.13E-06	5.06E-06	4.26E-01	1.87E-06	5.74E-06	3.42E-06	1.97E-06

Emissions Unit	Chrysene	Dibenzo(a,h)-anthracene	Dichloro-benzene	Ethylbenzene	Fluoranthene	Fluorene	Formaldehyde	Hexane	Indeno(1,2,3-cd)- pyrene	Naphthalene	PAH	Phena-nathrene	Propylene	Propylene Oxide
Emission Units Plant 1 CCGT	--	--	--	0.56	--	--	3.85	--	--	0.02	0.04	--	--	0.51
Auxiliary Boiler	7.31E-07	4.87E-07	4.87E-04	--	1.22E-06	1.14E-06	0.03	7.31E-01	7.31E-07	2.48E-04	--	6.90E-06	--	--
Emergency Generator	5.46E-06	1.23E-06	--	--	1.44E-05	4.57E-05	2.81E-04	--	1.48E-06	4.64E-04	--	1.46E-04	9.95E-03	--
Fire Pump	2.63E-07	4.34E-07	--	--	5.67E-06	2.17E-05	8.79E-04	--	2.79E-07	6.31E-05	--	2.19E-05	1.92E-03	--
	0.00	0.00	0.00	0.56	0.00	0.00	**3.88**	0.73	2.49E-06	0.02	0.04	1.74E-04	0.012	0.51
Plant 2 Total	1.31E-06	4.45E-07	1.11E-04	5.60E-01	4.29E-06	1.37E-05	3.86	0.17	5.18E-07	2.29E-02	3.85E-02	3.51E-05	2.37E-03	0.51
Source Total	7.76E-06	2.60E-06	5.98E-04	1.12E+00	2.55E-05	8.23E-05	7.75	0.90	3.00E-06	4.65E-02	7.71E-02	2.09E-04	1.42E-02	1.02

Emissions Unit	Pyrene	Toluene	Xylene	Arsenic	Beryllium	Cadmium	Chromium	Cobalt	Manganese	Mercury	Nickel	Selenium	Total HAPs**	Single Highest HAP
Emission Units Plant 1 CCGT	--	2.28	1.12	--	--	--	--	--	--	--	--	--	9.41	Formaldehyde
Auxiliary Boiler	2.03E-06	1.38E-03	--	8.12E-05	4.87E-06	4.46E-04	5.68E-04	3.41E-05	1.54E-04	1.06E-04	8.52E-04	9.74E-06	0.77	
Emergency Generator	1.32E-05	1.00E-03	6.89E-04	--	--	--	--	--	--	--	--	--	0.02	
Fire Pump	3.56E-06	3.05E-04	2.12E-04	--	--	--	--	--	--	--	--	--	4.81E-03	
	0.00	2.28	1.12	8.12E-05	4.87E-06	4.46E-04	5.68E-04	3.41E-05	1.54E-04	1.06E-04	8.52E-04	9.74E-06	**10.20**	3.88
Plant 2 Total	3.82E-06	2.28E+00	1.12	1.85E-05	1.11E-06	1.02E-04	1.30E-04	7.78E-06	3.52E-05	2.41E-05	1.95E-04	2.22E-06	9.59	3.86
Source Total	2.26E-05	4.56E+00	2.24	9.97E-05	5.98E-06	5.48E-04	6.98E-04	4.19E-05	1.89E-04	1.30E-04	1.05E-03	1.20E-05	**19.79**	7.75

** PM2.5 listed is direct PM2.5*

** PM2.5 listed is direct PM2.5*
***Fugitve HAP emissions are always included in the source-wide emissions*

Note: The gray shaded cells indicate where limits are included.
Note: Pursuant to 326 IAC 6-3-2(d), the particulate emissions from surface coating operations shall be controlled by dry particulate filters and the Permittee shall operate the control devices in accordance with the manufacturer's specifications. Compliance with this standard, in conjuction with a conservative assumption of 95% capture and control, shall limit PM, PM10, and PM2.5 emissions from the surface coating operations to the values shown.

Appendix A: ATSD Emission Calculations
Facility Data

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Data Inputs for Calculations

A: GAS TURBINES WITH HRSG & DB (EACH UNIT)	VALUE	UNIT	REFERENCE
Number of Combustion Turbines	1	1 X 1 CC	APS
Operating Hours			
Total Maximum Operating hours	8,760	hrs/yr	
Total Maximum Operating hours for CTs firing Natural Gas	8,760	hrs/yr	
Total Maximum Operating hours for DBs	NA	hrs/yr	no duct burning per APS
Fuel for CT	Natural Gas		
Fuel for DB	NA		
GT Natural Heat Input (ISO) (Case 4)	4,077	MMBtu/hr - HHV	Case 4 - T218_MCE Emissions Estimate - 7/25/22
Duct Burner Heat Input (Max)	NA	MMBtu/hr - HHV	no duct burning per APS
Total Heat Input	4,077	MMBtu/hr - HHV	Case 4 - T218_MCE Emissions Estimate - 7/25/22
Natural Gas Heat Value HHV	23,413	Btu/lbm	T218_MCE Emissions Estimate - 7/25/22
Natural Gas Heat Value LHV	21,139	Btu/lbm	T218_MCE Emissions Estimate - 7/25/22
Natural Gas Density	NA	lb/scf	
Natural Gas Sulfur Content	0.5	grains/100 dscf	T218_MCE Emissions Estimate - 7/25/22
Natural Gas Ratio HHV/LHV	1.108	unitless	Calculation, T218_MCE Emissions Estimate - 7/25/22
HRSG Stack Exit Conditions			
NOx Concentration	2	ppmvd @ 15% O_2	T218_MCE Emissions Estimate - 7/25/22
CO Concentration	2	ppmvd @ 15% O_2	T218_MCE Emissions Estimate - 7/25/22
VOC Concentration	1	ppmvd @ 15% O_2	T218_MCE Emissions Estimate - 7/25/22
Ammonia Concentration (as Slip from SCR)	5	ppmvd @ 15% O_2	T218_MCE Emissions Estimate - 7/25/22
SO_2 to SO_3 Conversion			
CTG (combustion)	NA		Conversion of SO2 to H2SO4 provided onT218_MCE Emissions Estimate - 7/25/22
SCR Catalyst	NA		
Oxid Catalyst	NA		
Total	NA		
Stack Height	185.00	ft	
Stack Diameter	23.00	ft	

SUSD Emissions - Typical Scenario [1]			
Number of Start-up/Shutdown Events			
Cold Start	15	events per year	Conservative Assumption based Maximum Predicted Event Occurances of each event (plus 20%). Dispatch predictions with maximum predicted event occurances were provided by MCE on 7/22/22
Warm Start	175	events per year	
Hot Start	70	events per year	
Shutdown	260	events per year	
Duration of Start-up/Shutdown Events			
Cold Start	70	minutes/event	T208a_7HA.03 RRL startup emissions memo_AP_Maple Creek-Aug 2022_Rev A
Warm Start	60	minutes/event	
Hot Start	30	minutes/event	
Shutdown	12	minutes/event	
Minimum Downtime Prior to Events			
Cold Start	72	hours/event	T208a_7HA.03 RRL startup emissions memo_AP_Maple Creek-Aug 2022_Rev A
Warm Start	8	hours/event	
Hot Start	0	hours/event	
Shutdown	0	hours/event	

SUSD EMISSIONS (EACH UNIT)

Per GT/HRST Stack	Pounds (lbs) per Event						Reference
	NOx	CO	VOC	PM10/PM2.5		Fuel (MMBTU,HHV)	
Cold Start	420.0	310.0	100.0	15.8		2,250	T208a_7HA.03 RRL startup emissions memo_AP_Maple Creek-Aug 2022_Rev A
Warm Start	260.0	230.0	85.0	13.5		1,930	
Hot Start	135.0	200.0	80.0	6.8		825	
Shutdown	40.0	175.0	60.0	2.5		182	

Appendix A: Emission Calculations
Facility Data

Company Name: Maple Creek Energy LLC
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Permit Number: 153-49550-00056
Reviewer: Tamera Wessel

B: EMERGENCY DIESEL GENERATOR			
Number of Emergency Diesel Generators	1		
Engine Rating	2,012	HP	
Fuel	ULSD		
Operating Hours	100	Hrs/yr	
SO2 to SO3 conversion	10%		
C: EMERGENCY FIRE WATER PUMP			
Number of Emergency Fire Water Pump	1		
Engine Rating	420	HP	
Fuel	ULSD		
Operating Hours	100	Hrs/yr	
SO2 to SO3 conversion	10%		
D: AUXILIARY BOILER			
Number of Auxiliary Boiler	1		
Maximum Heat Input	96.00	MMBtu/hr	
Fuel	natural gas		
Operating Hours	2,000	Hrs/yr	
SO2 to SO3 conversion	10%		
E: GLOBAL WARMING POTENTIAL FOR GREENHOUSE GASES (2)			
CO_2	1	CO_2e	40 CFR Part 98 Table A-1
N_2O	298	CO_2e	40 CFR Part 98 Table A-1
CH_4	25	CO_2e	40 CFR Part 98 Table A-1

(1) These parameters represent a typical SU/SD operating scenario for a baseload combined cycle facility in order to estimate potential emissions.

Appendix A: ATSD Emission Calculations
PTE Summary

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Annual Emission Rate Summary (TPY)

Pollutant	HAP?	CCGT(1)	EMGEN (2)	FWP (2)	AUX BOILER (3)	SITE TOTAL
Particulate Matter (PM_{10})	no	59.57	0.033	0.01	0.72	**60.3**
Particulate Matter ($PM_{2.5}$)	no	59.57	0.033	0.01	0.72	**60.3**
Sulfur Oxides (SO_x)	no	28.47	0.001	0.0003	0.13	**28.6**
Nitrogen Oxides (NO_x)	no	136.12	1.1	0.1	3.6	**140.9**
Carbon Monoxide (CO)	no	112.69	0.6	0.1	3.6	**116.9**
Volatile Organic Compound (VOC)	no	36.14	0.1	0.0	0.3	**36.6**
Sulfuric Acid Mist (SAM)	no	19.27	1.53E-04	3.00E-05	0.01	**19.3**
Lead	yes				4.63E-05	**4.63E-05**
Greenhouse Gas (CO_2e)	no	2,065,094.06	125.05	24.52	11,243.60	**2,076,487**
1,3-Butadiene	yes	0.01	0.00E+00	5.82E-06		**7.54E-03**
2-Methylnaphthalene	no				2.22E-06	**2.22E-06**
3-Methylchloranthrene	no				1.67E-07	**1.67E-07**
7,12-Dimethylbenz(a)anthracene	no				1.48E-06	**1.48E-06**
Acenaphthene	no		3.34E-06	2.11E-07	1.67E-07	**3.72E-06**
Acenaphthylene	no		6.59E-06	7.54E-07	1.67E-07	**7.51E-06**
Acetaldehyde	yes	0.70	1.80E-05	1.14E-04		**0.70**
Acrolein	yes	0.11	5.62E-06	1.38E-05		**0.11**
Ammonia	no	117.82				**117.82**
Anthracene	no		8.78E-07	2.79E-07	2.22E-07	**1.38E-06**
Benz(a)anthracene	no		4.44E-07	2.50E-07	1.67E-07	**8.61E-07**
Benzene	yes	0.21	5.54E-04	1.39E-04	1.95E-04	**0.21**
Benzo(a)pyrene	no		Benzene (including benzene from gasoline)	2.80E-08	1.11E-07	**1.39E-07**
Benzo(b)fluoranthene	no		7.92E-07	1.48E-08	1.67E-07	**9.74E-07**
Benzo(g,h,i)perylene	no		3.97E-07	7.28E-08	1.11E-07	**5.81E-07**
Benzo(k)fluoranthene	no		1.56E-07	2.31E-08	1.67E-07	**3.45E-07**
Chrysene	no		1.09E-06	5.26E-08	1.67E-07	**1.31E-06**
Dibenzo(a,h)anthracene	no		2.47E-07	8.68E-08	1.11E-07	**4.45E-07**
Dichlorobenzene	yes				1.11E-04	**1.11E-04**
Ethylbenzene	yes	0.56				**0.56**
Fluoranthene	no		2.88E-06	1.13E-06	2.78E-07	**4.29E-06**
Fluorene	no		9.13E-06	4.35E-06	2.59E-07	**1.37E-05**
Formaldehyde	yes	3.85	5.63E-05	1.76E-04	6.95E-03	**3.86**
Hexane	yes				1.67E-01	**0.17**
Indeno(1,2,3-cd)pyrene	no		2.95E-07	5.59E-08	1.67E-07	**5.18E-07**
Naphthalene	yes	0.02	9.28E-05	1.26E-05	5.65E-05	**0.02**
Total PAH	yes	0.04	0.000151	0.000025		**0.04**
Phenanathrene	no		2.91E-05	4.38E-06	1.58E-06	**3.51E-05**
Propylene	no		1.99E-03	3.84E-04		**0.00**
Propylene Oxide	yes	0.51				**0.51**
Pyrene	no		2.65E-06	7.12E-07	4.63E-07	**3.82E-06**
Toluene	yes	2.28	2.00E-04	6.09E-05	3.15E-04	**2.28**
Xylene (mixed isomers)	yes	1.12	1.38E-04	4.24E-05		**1.12**
Arsenic	yes				1.85E-05	**1.85E-05**
Beryllium	yes				1.11E-06	**1.11E-06**
Cadmium	yes				1.02E-04	**1.02E-04**
Chromium	yes				1.30E-04	**1.30E-04**
Cobalt	yes				7.78E-06	**7.78E-06**
Manganese	yes				3.52E-05	**3.52E-05**
Mercury	yes				2.41E-05	**2.41E-05**
Nickel	yes				1.95E-04	**1.95E-04**
Selenium	yes				2.22E-06	**2.22E-06**
Highest Individual HAP		3.85	0.0006	0.0002	0.1668	**3.86**
Total HAPs		9.41	0.00122	0.00059	0.17494	**9.59**

Notes:
(1) Criteria emissions are based on the proposed controlled emission rates as provided in "CCGT Unit Summary".
For GHG and HAPs emissions the emissions are based on 8,760 hours of operation per year.
(2) Emissions are based on 100 hours of non-emergency operations per year.
(3) Emissions are based on 2000 hours of operations per year.

Appendix A: ATSD Emission Calculations
CTG Summary

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

SINGLE COMBUSTION TURBINE

				280	SU_SD event hours (without downtime)			
CRITERIA POLLUTANTS				2760	SU_SD event hours (inc. downtime)			
	Steady State Operation ONLY [1]			Steady State and SU_SD Operations[3]				
Pollutant	Hourly Emissions at ISO Conditions (lbs/hr)[2][5][6][7]	Maximum Hourly Emissions (lbs/hr)	Annual Emissions at ISO Conditions (ton/yr)	Emissions during SU/SD event hrs (TPY)	Emissions during Steady State Operating hrs (TPY)	Annual Emissions with SUSD and Steady State Operation (TPY)	Major Source Threshold (tpy)	SER (tpy)
Particulate Matter (PM_{10})	13.60	13.90	59.57	18.76	40.80	**59.57**	100	15
Particulate Matter ($PM_{2.5}$)	13.60	13.90	59.57	18.76	40.80	**59.57**	100	10
Sulfur Oxides (SO_x)	6.50	6.90	28.47	na	na	**28.47**	100	40
Nitrogen Oxides (NO_x)	29.10	30.90	127.46	48.81	87.31	**136.12**	100	40
Carbon Monoxide (CO)	17.70	18.80	77.53	59.59	53.10	**112.69**	100	100
Total Volatile Organic Compounds (VOC)	5.10	5.40	22.34	20.84	15.30	**36.14**	100	40
Sulfuric acid mist (SAM)	4.40	4.70	19.27	NA	NA	**19.27**	100	7

GHG

	Steady State Operation ONLY			Steady State and SU_SD Operations				
Pollutant	Hourly Emissions at ISO Conditions (lbs/hr)[2]	Maximum Hourly Emissions (lbs/hr)	Annual Emissions at ISO Conditions (ton/yr)	Emissions during SU/SD event hrs (TPY)	Emissions during Steady State Operating hrs (TPY)	Annual Emissions with SUSD and Steady State Operation (TPY)[4]	Major Source Threshold (tpy)	SER (tpy)
CO_2	471,000	501,000	2,062,980	NA	NA	2,062,980		
N_2O	0.88	0.94	3.86	NA	NA	4		
CH_4	8.81	9.37	38.58	NA	NA	39		
CO_2e	471,483	501,513	2,065,094	NA	NA	2,065,094	NA	75000

B: HAP/TAP

	Steady State Operation ONLY			Steady State and SU_SD Operations				
Pollutant	Hourly Emissions at ISO Conditions (lbs/hr)[2]	Maximum Hourly Emissions (lbs/hr)	Annual Emissions at ISO Conditions (ton/yr)	Emissions during SU/SD event hrs (TPY)	Emissions during Steady State Operating hrs (TPY)	Annual Emissions with SUSD and Steady State Operation (TPY)[4]	Major Source Threshold (tpy)	SER (tpy)
1,3 Butadiene	0.002	0.002	0.01	NA	NA	0.01		
Acetaldehyde	0.160	0.170	0.70	NA	NA	0.70		
Acrolein	0.026	0.027	0.11	NA	NA	0.11		
Ammonia	26.90	28.600	117.82	NA	NA	117.82		
Benzene	0.048	0.051	0.21	NA	NA	0.21		
Ethylbenzene	0.128	0.136	0.56	NA	NA	0.56		
Formaldehyde	0.880	0.936	3.85	NA	NA	3.85		
Naphthalene	0.005	0.006	0.02	NA	NA	0.02		
PAH	0.009	0.009	0.04	NA	NA	0.04		
Propylene Oxide	0.116	0.123	0.51	NA	NA	0.51		
Toluene	0.520	0.553	2.28	NA	NA	2.28		
Xylene (Total)	0.256	0.272	1.12	NA	NA	1.12		
Maximum Indvidual HAP						3.85	10	NA
Total HAPs						9.41	25	NA

Notes:
[1] CTG/HRSG Emissions provided by GE "1592244 AP - Maple Creek Plant Emissions Estimate Rev -.xlsx"
[2] ISO Conditions are considered to be Case 4 (59°F/EC on)
[3] Refer to "GE SU SD" tab for calculations
[4] Steady State emissions are considered worst-case as emissions for these pollutants are based on fuel consumption.
[5] Assumes 80% control of NOX from selective catalytic reduction system to estimate uncontrolled emission factor. Actual control efficiency will vary based on ambient air and load conditions.
[6] Assumes 80% control of CO from oxidation catalyst to estimate uncontrolled emission factor. Actual control efficiency will vary based on ambient air and load conditions.
[7] Assumes 25% control of VOC from oxidation catalyst to estimate uncontrolled emission factor. Actual control efficiency will vary based on ambient air and load conditions.

Appendix A: ATSD Emission Calculations
CGT Data

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Combined Cycle Systems Emissions Estimates: AP - Maple Creek															
Operating Point		3	4	5	6	8	9	10	11	12	13	14	15	16	
Case Description		-20°F, Gas fuel, 1 GT @ 100% load	-20°F, Gas fuel, 1 GT @ 27.8% load	16°F, Gas fuel, 1 GT @ 100% load	16°F, Gas fuel, 1 GT @ 19.2% load	59°F, Gas fuel, 1 GT @ 100% load, EC on	59°F, Gas fuel, 1 GT @ 97.9% load	59°F, Gas fuel, 1 GT @ 19.6% load	87°F, Gas fuel, 1 GT @ 100% load, EC on	87°F, Gas fuel, 1 GT @ 93.9% load	87°F, Gas fuel, 1 GT @ 20.2% load	105°F, Gas fuel, 1 GT @ 100% load, EC on	105°F, Gas fuel, 1 GT @ 89.7% load	105°F, Gas fuel, 1 GT @ 21.7% load	Maximum
Ambient Conditions															
Ambient Temperature	°F	-20.0	-20.0	16.0	16.0	59.0	59.0	59.0	87.0	87.0	87.0	105.0	105.0	105.0	
Ambient Pressure	psia	14.4	14.4	14.411	14.411	14.4	14.4	14.4	14.411	14.411	14.411	14.4	14.4	14.4	
Ambient Relative Humidity	%	86.0	86.0	76	76	60.0	60.0	60.0	49	49	49	49.0	49.0	49.0	
Gas Turbine															
GT Fuel Type		Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	
Number of Gas Turbines operating per Block		1.0	1.0	1	1	1.0	1.0	1.0	1	1	1	1.0	1.0	1.0	
GT load fraction	-	1.0	0.3	1	0.192	1.0	1.0	0.2	1	0.939	0.202	1.0	0.9	0.2	
Evap Cooler status		off	off	off	off	On	off	off	On	off	off	On	off	off	
Gas turbine water injection flow rate	klb/h	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Abatement Status															
CO Catalyst Operating status		Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	
SCR Operating status		Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	
GT Fuel															
Gas Turbine fuel LHV	Btu/lb	21139	21139	21139	21139	21139	21139	21139	21139	21139	21139	21139	21139	21139	
Gas Turbine fuel HHV	Btu/lb	23413	23413	23413	23413	23413	23413	23413	23413	23413	23413	23413	23413	23413	
Gas Turbine gas fuel molecular weight	lb/lbmole	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	
Gas Turbine sulfur ppm (by mass)	ppm	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	
Duct Burner															
Duct Burner fuel LHV	Btu/lb	21139	21139	21139	21139	21139	21139	21139	21139	21139	21139	21139	21139	21139	
Duct Burner fuel HHV	Btu/lb	23413	23413	23413	23413	23413	23413	23413	23413	23413	23413	23413	23413	23413	
Duct Burner fuel molecular weight	lb/lbmole	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	
Duct Burner fuel sulfur content (by mass)	ppm	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	
Duct Burner status		Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	
Duct Burner gas fuel flow	klb/h	0	0	0.0	0.0	0	0	0	0.0	0.0	0.0	0	0	0	
Duct Burner load fraction	%	0	0	0.0	0.0	0	0	0	0.0	0.0	0.0	0	0	0	
Heat Consumption for permitting (per unit)															
GT Heat Cons (HHV), with permitting margin	MMBtu/h	4252.4	1777.7	4188.8	1455.9	4077.3	3998.7	1440.8	3989.2	3776.7	1407.1	3765.9	3438.2	1394.4	
DB Heat Cons (HHV)	MMBtu/h	0	0	0.0	0.0	0	0	0	0.0	0.0	0.0	0	0	0	
HRSG Exit Exhaust gas (per unit)															
Stack N2 mole fraction	-	0.7452	0.7549	0.7443	0.7522	0.7362	0.7382	0.7469	0.7266	0.7303	0.7384	0.7148	0.7191	0.7263	
Stack O2 mole fraction	-	0.1079	0.1356	0.109	0.1317	0.106	0.107	0.1322	0.1049	0.1065	0.1301	0.1036	0.105	0.1265	
Stack AR mole fraction	-	0.008873	0.008988	0.008863	0.008957	0.008766	0.008789	0.008893	0.008652	0.008696	0.008793	0.008511	0.008562	0.008648	
Stack H2O mole fraction	-	0.09084	0.06611	0.09129	0.07103	0.1021	0.09934	0.077	0.1136	0.1085	0.08767	0.1278	0.1222	0.1034	
Stack CO2 mole fraction	-	0.04715	0.03434	0.04647	0.03598	0.04685	0.04664	0.03501	0.04613	0.04579	0.03488	0.04517	0.04502	0.03508	
Stack Molecular Weight	lb/lbmole	28.39	28.55	28.38	28.51	28.27	28.3	28.43	28.13	28.19	28.32	27.97	28.03	28.15	
Stack Temperature	°F	198.7	199.1	198.6	178.6	194.9	194.3	179.1	207.5	203.8	178.7	220.2	213	188.8	
Stack Mass flow, including Permitting Margin, per stack	lb/h	6850200	3962300	6843600	3092200	6579800	6489200	3136600	6508300	6218400	3062000	6238000	5725900	2998300	
Margined exhaust vol flow (incl. permitting margin)	Mft3/h	118.28	68.088	118.2	51.558	113.47	111.69	52.472	114.93	109	51.403	112.91	102.34	51.444	
HRSG Exit Emissions (per unit)															
NOx Volume fraction, dry, at 15 % O2	ppm	2	2	2	2	2	2	2	2	2	2	2	2	2	
NOx mass flow rate (as NO2)	lb/h	30.9	12.9	30.4	10.6	29.6	29.1	10.5	29.0	27.4	10.2	27.4	25	10.1	30.9
CO Volume fraction, dry, at 15 % O2	ppm	2	2	2	2	2	2	2	2	2	2	2	2	2	
CO mass flow rate	lb/h	18.8	7.8	18.5	6.4	18	17.7	6.4	17.7	16.7	6.2	16.7	15.2	6.2	18.8
VOC Volume fraction, dry, at 15 % O2	ppm	1	1	1	1	1	1	1	1	1	1	1	1	1	
VOC mass flow rate (as methane)	lb/h	5.4	2.2	5.3	1.8	5.2	5.1	1.8	5.1	4.8	1.8	4.8	4.4	1.8	5.4
NH3 Volume fraction, dry, at 15 % O2	ppm	5	5	5	5	5	5	5	5	5	5	5	5	5	
NH3 mass flow rate	lb/h	28.6	11.9	28.2	9.8	27.4	26.9	9.7	26.8	25.4	9.4	25.3	23.1	9.4	28.6
SOx mass flow rate (as SO2)	lb/h	6.9	2.9	6.8	2.4	6.6	6.5	2.3	6.5	6.2	2.3	6.1	5.6	2.3	6.9
Total Particulates	lb/h	13.9	8.68	13.8	7.7	13.7	13.6	7.86	13.6	13.3	7.9	13.3	12.9	8.03	13.9
Sulfur Mist as H2SO4	lb/h	4.7	2.0	4.6	1.6	4.5	4.4	1.6	4.4	4.2	1.5	4.1	3.8	1.5	4.7
Stack CO2 mass flow rate, including Permitting margin	lb/h	501000	210000	493000	172000	480000	471000	170000	470000	445000	166000	443000	405000	164000	501000.0
Total Particulates	lb/MMBtu	0.0033	0.0049	0.0033	0.0053	0.0034	0.0034	0.0055	0.0034	0.0035	0.0056	0.0035	0.0038	0.0058	0.00576
Sulfur Mist as H2SO4	lb/MMBtu	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.00113
NOx mass flow rate (as NO2)	lb/MMBtu	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0072	0.0073	0.0073	0.0072	0.00729
CO mass flow rate	lb/MMBtu	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.00445
VOC mass flow rate (as methane)	lb/MMBtu	0.0013	0.0012	0.0013	0.0012	0.0013	0.0013	0.0012	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.00129
SOx mass flow rate (as SO2)	lb/MMBtu	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.00165

HAP and Other GHGs (lb/hr)

		3	4	5	6	8	9	10	11	12	13	14	15	16	Maximum lb/hr
LOAD LEVEL		-20°F, Gas fuel, 1 GT @ 100% load	-20°F, Gas fuel, 1 GT @ 27.8% load	16°F, Gas fuel, 1 GT @ 100% load	16°F, Gas fuel, 1 GT @ 19.2% load	59°F, Gas fuel, 1 GT @ 100% load, EC on	59°F, Gas fuel, 1 GT @ 97.9% load	59°F, Gas fuel, 1 GT @ 19.6% load	GT @ 100% load, EC on	87°F, Gas fuel, 1 GT @ 93.9% load	87°F, Gas fuel, 1 GT @ 20.2% load	GT @ 100% load, EC on	105°F, Gas fuel, 1 GT @ 89.7% load	105°F, Gas fuel, 1 GT @ 21.7% load	
AMBIENT DRY BULB TEMPERATURE, °F		-20	-20	16	16	59	59	59	87	87	87	105	105	105	
methane (CH4)	2.20E-03	9.37E+00	3.92E+00	9.23E+00	3.21E+00	8.98E+00	8.81E+00	3.17E+00	8.79E+00	8.32E+00	3.10E+00	8.29E+00	7.57E+00	3.07E+00	9.37E+00
nitrous oxide (N2O)	2.20E-04	9.37E-01	3.92E-01	9.23E-01	3.21E-01	8.98E-01	8.81E-01	3.17E-01	8.79E-01	8.32E-01	3.10E-01	8.29E-01	7.57E-01	3.07E-01	9.37E-01
1,3 Butadiene	4.30E-07	1.83E-03	7.64E-04	1.80E-03	6.26E-04	1.75E-03	1.72E-03	6.20E-04	1.72E-03	1.62E-03	6.05E-04	1.62E-03	1.48E-03	6.00E-04	1.83E-03
Acetaldehyde	4.00E-05	1.70E-01	7.11E-02	1.68E-01	5.82E-02	1.63E-01	1.60E-01	5.76E-02	1.60E-01	1.51E-01	5.63E-02	1.51E-01	1.38E-01	5.58E-02	1.70E-01
Acrolein	6.40E-06	2.72E-02	1.14E-02	2.68E-02	9.32E-03	2.61E-02	2.56E-02	9.22E-03	2.55E-02	2.42E-02	9.01E-03	2.41E-02	2.20E-02	8.92E-03	2.72E-02
Benzene	1.20E-05	5.10E-02	2.13E-02	5.03E-02	1.75E-02	4.89E-02	4.80E-02	1.73E-02	4.79E-02	4.53E-02	1.69E-02	4.52E-02	4.13E-02	1.67E-02	5.10E-02
Ethylbenzene	3.20E-05	1.36E-01	5.69E-02	1.34E-01	4.66E-02	1.30E-01	1.28E-01	4.61E-02	1.28E-01	1.21E-01	4.50E-02	1.21E-01	1.10E-01	4.46E-02	1.36E-01
Formaldehyde (MACT Limit for CTG)	2.20E-04	9.36E-01	3.91E-01	9.22E-01	3.20E-01	8.97E-01	8.80E-01	3.17E-01	8.78E-01	8.31E-01	3.10E-01	8.28E-01	7.56E-01	3.07E-01	9.36E-01
Naphthalene	1.30E-06	5.53E-03	2.31E-03	5.45E-03	1.89E-03	5.30E-03	5.20E-03	1.87E-03	5.19E-03	4.91E-03	1.83E-03	4.90E-03	4.47E-03	1.81E-03	5.53E-03
PAH	2.20E-06	9.36E-03	3.91E-03	9.22E-03	3.20E-03	8.97E-03	8.80E-03	3.17E-03	8.78E-03	8.31E-03	3.10E-03	8.28E-03	7.56E-03	3.07E-03	9.36E-03
Propylene Oxide	2.90E-05	1.23E-01	5.16E-02	1.21E-01	4.22E-02	1.18E-01	1.16E-01	4.18E-02	1.16E-01	1.10E-01	4.08E-02	1.09E-01	9.97E-02	4.04E-02	1.23E-01
Toluene	1.30E-04	5.53E-01	2.31E-01	5.45E-01	1.89E-01	5.30E-01	5.20E-01	1.87E-01	5.19E-01	4.91E-01	1.83E-01	4.90E-01	4.47E-01	1.81E-01	5.53E-01
Xylene (Total)	6.40E-05	2.72E-01	1.14E-01	2.68E-01	9.32E-02	2.61E-01	2.56E-01	9.22E-02	2.55E-01	2.42E-01	9.01E-02	2.41E-01	2.20E-01	8.92E-02	2.72E-01

Appendix A: ATSD Emission Calculations
CGT Data

Company Name:	Maple Creek Energy LLC
Source Address:	W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM:	153-49550-00056
Permit Number SPM:	153-50217-00056
Reviewer:	Tamera Wessel

Project information

Advance Power/ Maple Creek
IN
A. Kos
22-Jul-2022
1 block(s) 1x1 7HA.03_NG only SS A650-40LSB ACC
Design Point HRSG Steam conditions: 2338#/1085F/1085F
Duct firing: None
ITD or (TTD + Trise + Twb aprch): 47.6F
Ambient pressure: 14.4107 psia

SUMMARY TABLE

Case **Description**		HB_NG_1 1x GT @100%; Evap Cooler OFF, Duct Burner OFF	HB_NG_2 1x GT @75%; Evap Cooler OFF, Duct Burner OFF	HB_NG_3 1x GT @62%; Evap Cooler OFF, Duct Burner OFF	HB_NG_4 1x GT @100%; Evap Cooler ON, Duct Burner OFF	HB_NG_5 1x GT @100%; Evap Cooler OFF, Duct Burner OFF	HB_NG_6 1x GT @75%; Evap Cooler OFF, Duct Burner OFF	HB_NG_7 1x GT @29%; Evap Cooler OFF, Duct Burner OFF	HB_NG_8 1x GT @100%; Evap Cooler ON, Duct Burner OFF	HB_NG_9 1x GT @100%; Evap Cooler OFF, Duct Burner OFF	HB_NG_10 1x GT @75%; Evap Cooler OFF, Duct Burner OFF	HB_NG_11 1x GT @36%; Evap Cooler OFF, Duct Burner OFF
Ambient temperature/ Relative humidity		-15°F/86%RH	-15°F/86%RH	-15°F/86%RH	59°F/60%RH	59°F/60%RH	59°F/60%RH	59°F/60%RH	105°F/49%RH	105°F/49%RH	105°F/49%RH	105°F/49%RH
Gross output	kW	629,948	493,467	421,421	634,067	630,459	488,112	237,833	564,011	513,755	398,976	222,837
Gross heat rate- LHV	Btu/kWh	5,579	5,714	5,852	5,447	5,440	5,550	6,381	5,706	5,721	5,891	6,665
Gross heat rate-HHV	Btu/kWh	6,183	6,332	6,486	6,036	6,029	6,152	7,073	6,324	6,341	6,529	7,387
Estimated plant aux load	kW	10,688	9,156	8,504	12,556	12,527	10,912	7,961	11,840	11,258	10,002	8,536
Plant aux load (% of Gross output)	-	1.70%	1.86%	2.02%	1.98%	1.99%	2.24%	3.35%	2.10%	2.19%	2.51%	3.83%
Net plant output	**kW**	**619,261**	**484,312**	**412,917**	**621,511**	**617,931**	**477,201**	**229,872**	**552,172**	**502,497**	**388,974**	**214,301**
Net plant heat rate- LHV	Btu/kWh	5,675	5,822	5,972	5,557	5,550	5,677	6,602	5,829	5,849	6,042	6,930
Net plant efficiency- LHV	%	60.13%	58.61%	57.13%	61.41%	61.47%	60.10%	51.68%	58.54%	58.33%	56.47%	49.23%
Net plant heat rate- HHV	Btu/kWh	6,289	6,452	6,619	6,158	6,152	6,292	7,318	6,460	6,483	6,696	7,681
Net plant efficiency- HHV	%	54.25%	52.88%	51.55%	55.41%	55.47%	54.23%	46.63%	52.82%	52.63%	50.95%	44.42%
GT Load		100%	75%	62%	100%	100%	75%	29%	100%	100%	75%	36%
Duct Burner Heat Consumption (all HRSGs)- HHV	MBtu/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HP Throttle P	psia	2301	1953	1767	2379	2376	1940	1309	2317	2169	1802	1315
ST exhaust pressure	inHg	2.713	2.000	2.000	2.713	2.713	2.100	2.000	8.816	8.240	6.841	5.275
LP Annulus Velocity	ft/s	760	861	787	779	779	820	600	265	266	266	252
DB exit temp	°F	1100	1118	1116	1114	1114	1118	1109	1115	1123	1117	1110

Fuel properties (all GTs)		HB_NG_1	HB_NG_2	HB_NG_3	HB_NG_4	HB_NG_5	HB_NG_6	HB_NG_7	HB_NG_8	HB_NG_9	HB_NG_10	HB_NG_11
HHV/LHV ratio	-	1.108	1.108	1.108	1.108	1.108	1.108	1.108	1.108	1.108	1.108	1.108
LHV (mass)	Btu/lb	20,515.9	20,515.9	20,515.9	20,515.9	20,515.9	20,515.9	20,515.9	20,515.9	20,515.9	20,515.9	20,515.9
HHV (mass)	Btu/lb	22,737.8	22,737.8	22,737.8	22,737.8	22,737.8	22,737.8	22,737.8	22,737.8	22,737.8	22,737.8	22,737.8
LHV (vol)	Btu/ft³	924.8	924.8	924.8	924.8	924.8	924.8	924.8	924.8	924.8	924.8	924.8
HHV (vol)	Btu/ft³	1,025.0	1,025.0	1,025.0	1,025.0	1,025.0	1,025.0	1,025.0	1,025.0	1,025.0	1,025.0	1,025.0

ESTIMATED AUX LOADS		HB_NG_1	HB_NG_2	HB_NG_3	HB_NG_4	HB_NG_5	HB_NG_6	HB_NG_7	HB_NG_8	HB_NG_9	HB_NG_10	HB_NG_11
GE Aux	kW	1577	1596	1593	1587	1581	1596	1588	1570	1570	1570	1570
Rest of plat BOP aux												
Main step-up xformer	kW	2192	2192	2192	2192	2192	2192	2192	2192	2192	2192	2192
Lighting/ HVAC/Other	kW	1890	1480	1264	1902	1891	1464	713	1692	1541	1197	669
Vacuum pumps	kW	78	67	61	80	80	66	45	68	64	53	39
Condensate pump	kW	349	255	212	367	366	252	131	350	310	219	131
Boiler feed pump	kW	2960	2113	1734	3158	3149	2086	969	2980	2599	1798	975
Aux cooling load	kW	0	0	0	0	0	0	0	0	0	0	0
Water treatment &service air compressors	kW	150	150	150	150	150	150	150	150	150	150	150
ACC or WCT fans	kW	1419	1242	1242	3031	3031	3031	2122	2755	2755	2755	2755
WCT circ water pump	kW	0	0	0	0	0	0	0	0	0	0	0
Aux xformers and misc elec system losses	kW	73	60	55	88	88	75	51	82	78	67	56
Rest of plat BOP aux total	kW	9111	7559	6910	10969	10946	9316	6373	10270	9688	8432	6966
Total estimated plant aux load	kW	10688	9156	8504	12556	12527	10912	7961	11840	11258	10002	8536

Appendix A: ATSD Emission Calculations
Startup/Shutdown Emissions

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Mode	Events/year	Time (min) per event	Min Downtime before Event (hr)	Total Time per event (hr)	Total Pounds Per Event NOx	CO	VOC	PM		Fuel Use	Total Pounds Per Hour * VOC	PM
StartUp - Cold:	15	70	72	73.17	420	310	100	15.8		2,250	85.7	13.5
StartUp - Warm:	175	60	8	9.00	260	230	85	13.5		1930	85.0	13.5
StartUp - Hot:	70	30	0	0.50	135	200	80	6.8		825	160.0	13.6
Shutdown:	260	12	0	0.20	40	175	60	2.5		182	300.0	12.5

* Total Pounds Per Hour (lb/hr) = Total Pounds Per Event (lb/event) / (Time per event (min/event)/ 60 min /hr)

Maximum Hourly Emissions (for modeling)

		Total Time per event (min) (no downtime)	Total Event Time per Year (hr) (no downtime)	SU/SD Lb per min (not including downtime) NOx	CO	VOC	PM		Max Steady State lb per min NOx	CO	VOC	PM		Max Hourly Emissions During SU/SD Event NOx	CO	VOC	PM	
StartUp - Cold:	15	70.00	17.5	6.0	4.4	1.4	0.2		0.5	0.3	0.1	0.2		360.0	265.7	85.7	13.5	
StartUp - Warm:	175	60.00	175.0	4.3	3.8	1.4	0.2		0.5	0.3	0.1	0.2		260.0	230.0	85.0	13.5	
StartUp - Hot:	70	30.00	35.0	4.5	6.7	2.7	0.2		0.5	0.3	0.1	0.2		150.5	209.4	82.7	13.8	
Shutdown:	260	12.00	52.0	3.3	14.6	5.0	0.2		0.5	0.3	0.1	0.2		64.7	190.0	64.3	13.6	
TOTAL			279.5															

Annual Average Emissions

SU/SD hrs per year 279.5 w/o downtime
SU/SD hrs per year 2759.5 with downtime

	Events/year	Total Time per event (hr) (no downtime)	Annual Hours for SU/SD Events	SU/SD lb per yr (for SU/SD Hours including downtime) NOx	CO	VOC	PM		Normal Operation lb per year (for SU/SD Hours including downtime) NOx	CO	VOC	PM		Worst Case Annual Emissions lb per yr (During SU_SD Event Hours including downtime) NOx	CO	VOC	PM	SO2
StartUp - Cold:	15	1.17	1097.5	6300	4650	1500	237		31937	19426	5597	14926		31937	19426	5597	14926	0
StartUp - Warm:	175	1.00	1575.0	45500	40250	14875	2363		45833	27878	8033	21420		45833	40250	14875	21420	0
StartUp - Hot:	70	0.50	35.0	9450	14000	5600	476		1019	620	179	476		9450	14000	5600	476	0
Shutdown:	260	0.20	52.0	10400	45500	15600	650		1513	920	265	707		10400	45500	15600	707	0
TOTAL SU_SD EVENT HRS:		279.5	2759.5															
Annual Emissions During SU_SD Event Hours (inc. downtime) (tpy)			2759.5											48.8	59.6	20.8	18.8	0.0
Annual Emissions During Steady State Operation			6000.5											87.3	53.1	15.3	40.8	19.5
TOTAL			8760.0											**136.1**	**112.7**	**36.1**	**59.6**	**19.5**

A For pollutants that are self-correcting hourly emissions are during normal operation, for non self correcting pollutants, emissions are during SU/SD event.
B Incorporates SU/SD emissions for those pollutants that are not self-correcting as indicated with orange shading.
C Max Hourly Emissions During SU/SD event incorporates assumes steady state operation for the remainder of the hour.

Emissions for Modeling (lb/hr)

	Events/year	Total Time per event (min) (no downtime)	Max 1-hour NOx	CO	PM	8-hr NOx	CO	PM	24-hr NOx	CO	PM	Annual Average NOx	CO	PM
StartUp - Cold:	15	70	360.0	na	na	na	76.2	na	na	na	13.9	38.1	na	13.9
StartUp - Warm:	175	60	260.0	na	na	na	66.6	na	na	na	13.8	38.1	na	13.9
StartUp - Hot:	70	30	150.5	na	na	na	154.5	na	na	na	13.7	38.1	na	13.9
Shutdown:	260	12	64.7	na	na	na	154.5	na	na	na	13.9	38.1	na	13.9

Operating Scenarios (min of operation)

8-hr scenarios (480 min)	cold # of events	cold total minutes	warm # of events	warm total minutes	hot # of events	hot total minutes	shutdown # of events	shutdown total minutes	SS (minutes)	Minutes in Avg Period			
StartUp - Cold Scenario (min)	1	70		0		0	1	12	398	480			
StartUp - Warm Scenario		0	1	60		0	1	12	408	480			
StartUp - Hot Scenario[a]		0		0	3	90	3	36	354	480			
Shutdown:		0		0	3	90	3	36	354	480			
24-hr scenarios (1440 min)	**cold # of events**	**cold total minutes**	**warm # of events**	**warm total minutes**	**hot # of events**	**hot total minutes**	**shutdown # of events**	**shutdown total minutes**	**SS (minutes)**	**Minutes in Avg Period**	**Exhaust Flow during event (acfm)**	**steady state (acfm)**	**Time Wghtd Average (acfm)**
StartUp - Cold Scenario (min)	1	70		0		0	1	12	1358	1440	874,533	1,891,167	1,833,275
StartUp - Warm Scenario		0	3	180		0	3	36	1224	1440	874,533	1,891,167	1,738,672
StartUp - Hot Scenario[a]		0		0	9	270	9	108	1062	1440	874,533	1,891,167	1,624,300
Shutdown:		0		0		0	0	0	1440	1440	874,533	1,891,167	1,891,167
Annual Average scenarios	**cold # of events**	**cold total minutes**	**warm # of events**	**warm total minutes**	**hot # of events**	**hot total minutes**	**shutdown # of events**	**shutdown total minutes**	**SS (minutes)**	**Minutes in Avg Period**	**Exhaust Flow during event (acfm)**	**steady state (acfm)**	**Time Wghtd Average (acfm)**
SU/SD Events	15	1050	175	10500	70	2100	260	3120	508830	525600	874,533	1,891,167	1,858,730

a Assumed that CTG would run SS for at least 2 hr after each hot start.

Appendix A: ATSD Emission Calculations
Auxiliary Boiler

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Auxiliary Boiler Emission Calculations

Emission calculations shown below depict emissions from an auxiliary boiler with a maximum rating of 96 MMBTU/hr. Emission estimates are based on a maximum annual operating time of 2000 hours per year

Pollutant	Annual Operation (hrs/yr)	Limited Annual Operation (hrs/yr)	Boiler Size (MMBTU/hr)	Emission Factor (1)	Emission Factor Units(1)	Emissions (Potential to Emit)			
						Average (2) (lbs/hr)	Maximum (3) (lbs/hr)	Annual (tons/yr)	Limited Annual (4) (tons/yr)
Particulate Matter (PM_{10})	8760	2,000	96.00	0.7200	lb/hr	0.720	0.720	3.15	0.720
Particulate Matter ($PM_{2.5}$)	8760	2,000	96.00	0.7200	lb/hr	0.720	0.720	3.15	0.720
Sulfur Oxides (SO_x)	8760	2,000	96.00	0.1345	lb/hr	0.134	0.134	0.59	0.134
Nitrogen Oxides (NO_x)(5)	8760	2,000	96.00	3.5500	lb/hr	3.550	3.550	15.55	3.550
Carbon Monoxide (CO)	8760	2,000	96.00	3.5500	lb/hr	3.550	3.550	15.55	3.550
Total Volatile Organic Compounds (VOC)(5)	8760	2,000	96.00	0.3300	lb/hr	0.330	0.330	1.45	0.330
Sulfuric Acid Mist (as H_2SO_4)	8760	2,000	96.00	0.0001	lb/MMBTU	0.013	0.013	0.06	0.013
Lead	8760	2,000	96.00	4.83E-07	lb/MMBTU	0.000046	0.000046	0.00	0.000046
Carbon Dioxide (CO_2)	8760	2,000	96.00	1.17E+02	lb/MMBTU	11232.000	11232.000	49196.16	11232.00
Methane (CH_4)	8760	2,000	96.00	2.20E-03	lb/MMBTU	0.212	0.212	0.93	2.1E-01
Nitrous Oxide (N_2O)	8760	2,000	96.00	2.20E-04	lb/MMBTU	0.021	0.021	0.09	2.1E-02
CO_2e	8760	2,000	96.00	--	--	11243.60	11243.60	49246.96	11243.60
2-Methylnaphthalene	8760	2,000	96.00	2.32E-08	lb/MMBTU	0.0000022	0.0000022	9.74E-06	2.22E-06
3-Methylchloranthrene	8760	2,000	96.00	1.74E-09	lb/MMBTU	0.0000002	0.0000002	7.31E-07	1.67E-07
7,12-Dimethylbenz(a)anthracene	8760	2,000	96.00	1.54E-08	lb/MMBTU	0.0000015	0.0000015	6.49E-06	1.48E-06
Acenaphthene	8760	2,000	96.00	1.74E-09	lb/MMBTU	0.0000002	0.0000002	7.31E-07	1.67E-07
Acenaphthylene	8760	2,000	96.00	1.74E-09	lb/MMBTU	0.0000002	0.0000002	7.31E-07	1.67E-07
Anthracene	8760	2,000	96.00	2.32E-09	lb/MMBTU	0.0000002	0.0000002	9.74E-07	2.22E-07
Benz(a)anthracene	8760	2,000	96.00	1.74E-09	lb/MMBTU	0.0000002	0.0000002	7.31E-07	1.67E-07
Benzene	8760	2,000	96.00	2.03E-06	lb/MMBTU	0.0001946	0.0001946	8.52E-04	1.95E-04
Benzo(a)pyrene	8760	2,000	96.00	1.16E-09	lb/MMBTU	0.0000001	0.0000001	4.87E-07	1.11E-07
Benzo(b)fluoranthene	8760	2,000	96.00	1.74E-09	lb/MMBTU	0.0000002	0.0000002	7.31E-07	1.67E-07
Benzo(g,h,i)perylene	8760	2,000	96.00	1.16E-09	lb/MMBTU	0.0000001	0.0000001	4.87E-07	1.11E-07
Benzo(k)fluoranthene	8760	2,000	96.00	1.74E-09	lb/MMBTU	0.0000002	0.0000002	7.31E-07	1.67E-07
Chrysene	8760	2,000	96.00	1.74E-09	lb/MMBTU	0.0000002	0.0000002	7.31E-07	1.67E-07
Dibenzo(a,h)anthracene	8760	2,000	96.00	1.16E-09	lb/MMBTU	0.0000001	0.0000001	4.87E-07	1.11E-07
Dichlorobenzene	8760	2,000	96.00	1.16E-06	lb/MMBTU	0.0001112	0.0001112	4.87E-04	1.11E-04
Fluoranthene	8760	2,000	96.00	2.90E-09	lb/MMBTU	0.0000003	0.0000003	1.22E-06	2.78E-07
Fluorene	8760	2,000	96.00	2.70E-09	lb/MMBTU	0.0000003	0.0000003	1.14E-06	2.59E-07
Formaldehyde	8760	2,000	96.00	7.24E-05	lb/MMBTU	0.0069498	0.0069498	3.04E-02	6.95E-03
Hexane	8760	2,000	96.00	1.74E-03	lb/MMBTU	0.1667954	0.1667954	7.31E-01	1.67E-01
Indeno(1,2,3-cd)pyrene	8760	2,000	96.00	1.74E-09	lb/MMBTU	0.0000002	0.0000002	7.31E-07	1.67E-07
Naphthalene	8760	2,000	96.00	5.89E-07	lb/MMBTU	0.0000565	0.0000565	2.48E-04	5.65E-05
Phenanathrene	8760	2,000	96.00	1.64E-08	lb/MMBTU	0.0000016	0.0000016	6.90E-06	1.58E-06
Pyrene	8760	2,000	96.00	4.83E-09	lb/MMBTU	0.0000005	0.0000005	2.03E-06	4.63E-07
Toluene	8760	2,000	96.00	3.28E-06	lb/MMBTU	0.0003151	0.0003151	1.38E-03	3.15E-04
Arsenic	8760	2,000	96.00	1.93E-07	lb/MMBTU	0.0000185	0.0000185	8.12E-05	1.85E-05
Beryllium	8760	2,000	96.00	1.16E-08	lb/MMBTU	0.000001	0.000001	4.87E-06	1.11E-06
Cadmium	8760	2,000	96.00	1.06E-06	lb/MMBTU	0.0001019	0.0001019	4.46E-04	1.02E-04
Chromium	8760	2,000	96.00	1.35E-06	lb/MMBTU	0.0001297	0.0001297	5.68E-04	1.30E-04
Cobalt	8760	2,000	96.00	8.11E-08	lb/MMBTU	0.0000078	0.0000078	3.41E-05	7.78E-06
Manganese	8760	2,000	96.00	3.67E-07	lb/MMBTU	0.0000352	0.0000352	1.54E-04	3.52E-05
Mercury	8760	2,000	96.00	2.51E-07	lb/MMBTU	0.0000241	0.0000241	1.06E-04	2.41E-05
Nickel	8760	2,000	96.00	2.03E-06	lb/MMBTU	0.0001946	0.0001946	8.52E-04	1.95E-04
Selenium	8760	2,000	96.00	2.32E-08	lb/MMBTU	0.0000022	0.0000022	9.74E-06	2.22E-06
Total HAP								**0.77**	**0.17**

vendor data	0.7200 lb/hr	=	0.0075 lb/MMBTU
	0.7200 lb/hr	=	0.0075 lb/MMBTU
Based on 0.5 gr S /100 scf	0.1345 lb/hr	=	0.0014 lb/MMBTU
vendor data	3.5500 lb/hr	=	0.0370 lb/MMBTU
	3.5500 lb/hr	=	0.0370 lb/MMBTU
	0.3300 lb/hr	=	0.0034 lb/MMBTU
SO2 to SO3 Conversion	0.14 lb/MMscf	=	0.00014 lb/MMBTU
From AP-42 (7/98); Tables 1.4-2	5.00E-04 lb/MMscf		4.83E-07 lb/MMBTU
40 CFR 98 Table C-2	5.31E+01 kg/MMBtu		117.00 lb/MMBTU
	1.00E-03 kg/MMBtu	=	2.20E-03 lb/MMBTU
	1.00E-04 kg/MMBtu	=	2.20E-04 lb/MMBTU
NA	NA		NA
From AP-42 (7/98); Tables 1.4-3	2.40E-05 lb/MMscf	=	2.32E-08 lb/MMBTU
	1.80E-06 lb/MMscf	=	1.74E-09 lb/MMBTU
	1.60E-05 lb/MMscf	=	1.54E-08 lb/MMBTU
	1.80E-06 lb/MMscf	=	1.74E-09 lb/MMBTU
	1.80E-06 lb/MMscf	=	1.74E-09 lb/MMBTU
	2.40E-06 lb/MMscf	=	2.32E-09 lb/MMBTU
	1.80E-06 lb/MMscf	=	1.74E-09 lb/MMBTU
	2.10E-03 lb/MMscf	=	2.03E-06 lb/MMBTU
	1.20E-06 lb/MMscf	=	1.16E-09 lb/MMBTU
	1.80E-06 lb/MMscf		1.74E-09 lb/MMBTU
	1.20E-06 lb/MMscf		1.16E-09 lb/MMBTU
	1.80E-06 lb/MMscf		1.74E-09 lb/MMBTU
	1.80E-06 lb/MMscf		1.74E-09 lb/MMBTU
	1.20E-06 lb/MMscf		1.16E-09 lb/MMBTU
	1.20E-03 lb/MMscf		1.16E-06 lb/MMBTU
	3.00E-06 lb/MMscf		2.90E-09 lb/MMBTU
	2.80E-06 lb/MMscf		2.70E-09 lb/MMBTU
	7.50E-02 lb/MMscf		7.24E-05 lb/MMBTU
	1.80E+00 lb/MMscf		1.74E-03 lb/MMBTU
	1.80E-06 lb/MMscf		1.74E-09 lb/MMBTU
	6.10E-04 lb/MMscf		5.89E-07 lb/MMBTU
	1.70E-05 lb/MMscf		1.64E-08 lb/MMBTU
	5.00E-06 lb/MMscf		4.83E-09 lb/MMBTU
	3.40E-03 lb/MMscf		3.28E-06 lb/MMBTU
From AP-42 (7/98); Tables 1.4-4	2.00E-04 lb/MMscf		1.93E-07 lb/MMBTU
	1.20E-05 lb/MMscf		1.16E-08 lb/MMBTU
	1.10E-03 lb/MMscf		1.06E-06 lb/MMBTU
	1.40E-03 lb/MMscf		1.35E-06 lb/MMBTU
	8.40E-05 lb/MMscf		8.11E-08 lb/MMBTU
From AP-42 (7/98); Tables 1.4-4	3.80E-04 lb/MMscf		3.67E-07 lb/MMBTU
	2.60E-04 lb/MMscf		2.51E-07 lb/MMBTU
	2.10E-03 lb/MMscf		2.03E-06 lb/MMBTU
	2.40E-05 lb/MMscf		2.32E-08 lb/MMBTU

Notes

(1) Criteria pollutant emission provided in lb/hr from vendor data.
HAP emission factors referenced from AP-42, Chapter 1.4
CO2, CH4 and N2O emission factors based on 40 CFR 98 Table C-2
Sulfuric Acid Mist (as H_2SO_4) emissions provided by vendor, based on 10% conversion

(2) If emission factor provided as lb/hr, those emission factors are assumed for emissions (lb/hr), OR
Calculated as: Boiler Size (MMBTU/hr) **X** Emission Factor (lbs/MMBTU)

(3) Maximum emissions assumed to same as average emissions

(4) Calculated as: Emissions (lbs/hr) **X** Annual Operation (hrs/yr) ÷ 2,000 lbs/ton

(5) CO2e emissions = CO2 Emissions *CO2 GWP + CH4 Emissions * CH4 GWP + N2O Emissions * N2O GWP

Appendix A: ATSD Emission Calculations
Emergency Generator Emissions

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Emergency Diesel Generator Emission Calculations

Emission calculations shown below depict emissions from an emergency use diesel-fired generator engine with a maximum horsepower rating of 1500 kW (2,012 HP). Emission estimates are based on a maximum annual operating time of 100 non-emergency hours per year.

Pollutant	Annual Operation (hrs/yr)	Limited Annual Operation (hrs/yr)	Engine Size (HP)	Emission Factor (1) (lbs/HP-hr)	Emissions (Potential to Emit) Average (2) (lbs/hr)	Maximum(3) (lbs/hr)	Annual (4) (tons/yr)	Limited Annual (4) (tons/yr)
Particulate Matter (PM_{10})	500	100	2,012	0.000331	0.665	0.665	0.17	0.033
Particulate Matter ($PM_{2.5}$)	500	100	2,012	0.000331	0.665	0.665	0.17	0.033
Sulfur Oxides (SO_x)	500	100	2,012	0.000012	0.024	0.024	0.01	0.001
Nitrogen Oxides (NO_x)(5)	500	100	2,012	0.010582	21.291	21.291	5.32	1.065
Carbon Monoxide (CO)	500	100	2,012	0.005754	11.577	11.577	2.89	0.579
Total Volatile Organic Compounds (VOC)(5)	500	100	2,012	0.000705	1.419	1.419	0.35	0.071
Sulfuric Acid Mist (as H_2SO_4)	500	100	2,012	0.000002	0.003	0.003	7.65E-04	0.00015
1,3-Butadiene	500	100	2,012	0.00E+00	0.000	0.000	0.00E+00	0.000
Acenaphthene	500	100	2,012	3.32E-08	0.000	0.000	1.67E-05	0.000
Acenaphthylene	500	100	2,012	6.55E-08	1.3E-04	1.3E-04	3.29E-05	6.6E-06
Acetaldehyde	500	100	2,012	1.79E-07	3.6E-04	3.6E-04	8.99E-05	1.80E-05
Acrolein	500	100	2,012	5.59E-08	1.1E-04	1.1E-04	2.81E-05	5.62E-06
Anthracene	500	100	2,012	8.72E-09	1.8E-05	1.8E-05	4.39E-06	8.78E-07
Benz(a)anthracene	500	100	2,012	4.41E-09	8.9E-06	8.9E-06	2.22E-06	4.44E-07
Benzene	500	100	2,012	5.50E-06	0.011	0.011	2.77E-03	5.54E-04
Benzo(a)pyrene	500	100	2,012	1.82E-09	0.000	0.000	9.17E-07	1.83E-07
Benzo(b)fluoranthene	500	100	2,012	7.87E-09	1.6E-05	1.6E-05	3.96E-06	7.92E-07
Benzo(g,h,i)perylene	500	100	2,012	3.94E-09	7.9E-06	7.9E-06	1.98E-06	3.97E-07
Benzo(k)fluoranthene	500	100	2,012	1.55E-09	3.1E-06	3.1E-06	7.78E-07	1.56E-07
Chrysene	500	100	2,012	1.09E-08	2.2E-05	2.2E-05	5.46E-06	1.09E-06
Dibenzo(a,h)anthracene	500	100	2,012	2.45E-09	4.9E-06	4.9E-06	1.23E-06	2.47E-07
Fluoranthene	500	100	2,012	2.86E-08	5.8E-05	5.8E-05	1.44E-05	2.88E-06
Fluorene	500	100	2,012	9.08E-08	1.8E-04	1.8E-04	4.57E-05	9.13E-06
Formaldehyde	500	100	2,012	5.60E-07	0.001	0.001	2.81E-04	5.63E-05
Indeno(1,2,3-cd)pyrene	500	100	2,012	2.94E-09	5.9E-06	5.9E-06	1.48E-06	2.95E-07
Naphthalene	500	100	2,012	9.22E-07	0.002	0.002	4.64E-04	9.28E-05
Phenanathrene	500	100	2,012	2.89E-07	5.8E-04	5.8E-04	1.46E-04	2.91E-05
Propylene	500	100	2,012	1.98E-05	0.040	0.040	9.95E-03	1.99E-03
Pyrene	500	100	2,012	2.63E-08	5.3E-05	5.3E-05	1.32E-05	2.65E-06
Toluene	500	100	2,012	1.99E-06	0.004	0.004	1.00E-03	2.00E-04
Xylene (mixed isomers)	500	100	2,012	1.37E-06	0.003	0.003	6.89E-04	1.38E-04
Carbon Dioxide (CO_2 or CO_2e)	500	100	2,012	1.24E+00	2,492.485	2492.485	623.12	124.62
Methane (CH_4)	500	100	2,012	5.02E-05	0.101	0.101	0.03	0.005
Nitrous Oxide (N_2O)	500	100	2,012	1.00E-05	0.020	0.020	5.06E-03	0.001
CO_2e	500	100	2,012	--	2501.04	2501.04	625.26	125.05

CI ICE Tier 2	0.15 g/HP-hr	=	0.000331 lbs/HP-hr
CI ICE Tier 2	0.15 g/HP-hr	=	0.000331 lbs/HP-hr
ULSD sulfur content	15 ppm S in Fuel	=	0.000012 lbs/HP-hr
Vendor Information	4.80 g/HP-hr	=	0.010582 lbs/HP-hr
CI ICE Tier 2	2.61 g/HP-hr	=	0.005754 lbs/HP-hr
Vendor Information	0.32 g/HP-hr	=	0.000705 lbs/HP-hr
SO2 to SO3 Conversion	1.52E-06 lbs/HP-hr	=	1.52E-06 lbs/HP-hr
AP-42 (10/96); Tables 3.4-3 and 3.4-4	0.00E+00 lbs/MMBtu	=	0.00E+00lbs/HP-hr
	4.68E-06 lbs/MMBtu	=	3.32E-08lbs/HP-hr
	9.23E-06 lbs/MMBtu	=	6.55E-08lbs/HP-hr
	2.52E-05 lbs/MMBtu	=	1.79E-07lbs/HP-hr
	7.88E-06 lbs/MMBtu	=	5.59E-08lbs/HP-hr
	1.23E-06 lbs/MMBtu	=	8.72E-09lbs/HP-hr
	6.22E-07 lbs/MMBtu	=	4.41E-09lbs/HP-hr
	7.76E-04 lbs/MMBtu	=	5.50E-06lbs/HP-hr
	2.57E-07 lbs/MMBtu	=	1.82E-09lbs/HP-hr
	1.11E-06 lbs/MMBtu	=	7.87E-09lbs/HP-hr
	5.56E-07 lbs/MMBtu	=	3.94E-09lbs/HP-hr
	2.18E-07 lbs/MMBtu	=	1.55E-09lbs/HP-hr
	1.53E-06 lbs/MMBtu	=	1.09E-08lbs/HP-hr
	3.46E-07 lbs/MMBtu	=	2.45E-09lbs/HP-hr
	4.03E-06 lbs/MMBtu	=	2.86E-08lbs/HP-hr
	1.28E-05 lbs/MMBtu	=	9.08E-08lbs/HP-hr
	7.89E-05 lbs/MMBtu	=	5.60E-07lbs/HP-hr
	4.14E-07 lbs/MMBtu	=	2.94E-09lbs/HP-hr
	1.30E-04 lbs/MMBtu	=	9.22E-07lbs/HP-hr
	4.08E-05 lbs/MMBtu	=	2.89E-07lbs/HP-hr
	2.79E-03 lbs/MMBtu	=	1.98E-05lbs/HP-hr
	3.71E-06 lbs/MMBtu	=	2.63E-08lbs/HP-hr
	2.81E-04 lbs/MMBtu	=	1.99E-06lbs/HP-hr
	1.93E-04 lbs/MMBtu	=	1.37E-06lbs/HP-hr
NA	NA		NA
	NA		NA
40 CFR 98 Table C-2	7.40E+01 lbs/MMBtu	=	1.24E+00lbs/HP-hr
	3.00E-03 kg/MMBtu	=	5.02E-05lbs/HP-hr
	6.00E-04 kg/MMBtu	=	1.00E-05lbs/HP-hr

Notes

(1) Sources:
- PM_{10} and CO emission factors based on EPA emission certification for Tier 2 engine
- SO_x based on use of ULSD
- NO_x emission factors based CI ICE Tier 2 Standard for Nox + NMHC
- VOC emissions provided by vendor, who used emission factor from AP-42 Table 3.4-1
- Spectated organics: AP-42 Emission Factors
- CO2, CH_4 and N_2O emission factors based on 40 CFR 98 Table C-2
- Sulfuric Acid Mist (as H_2SO_4) emissions provided by vendor, based on 10% conversion

(2) Calculated as: Engine Size (HP) **X** Emission Factor (lbs/HP-hr)

(3) Maximum emissions assumed to same as average emissions

(4) Calculated as: Emissions (lbs/hr) **X** Annual Operation (hrs/yr) ÷ 2,000 lbs/ton

(5) NOx emissions are depicted at a rate of 4.8 g/hp-hr for conservative permitting purposes; however, NOx + NMHC emissions from the unit will not exceed 4.8 g/hp-hr, as specified in 40 CFR 60 Subpart IIII.

(6) CO2e emissions = CO2 Emissions *CO2 GWP + CH4 Emissions * CH4 GWP + N2O Emissions * N2O GWP

Appendix A: ATSD Emission Calculations
Fire Pump Emissions

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Emergency Fire Water Pump Emission Calculations

Emission calculations shown below depict emissions from an emergency use diesel-fired fire water pump engine with a maximum horsepower rating of 420 HP. Emission estimates are based on a maximum annual operating time of 100 non-emergency hours per year

Pollutant	Annual Operation (hrs/yr)	Limited Annual Operation (hrs/yr)	Engine Size (HP)	Emission Factor (1) (lbs/HP-hr)	Emissions (Potential to Emit)			
					Average (2) (lbs/hr)	Maximum (3) (lbs/hr)	Annual (4) (tons/yr)	Limited Annual (4) (tons/yr)
Particulate Matter (PM_{10})	500	100	420	0.000331	0.139	0.139	0.035	0.0069
Particulate Matter ($PM_{2.5}$)	500	100	420	0.000331	0.139	0.139	0.035	0.0069
Sulfur Oxides (SO_x)	500	100	420	0.000012	0.005	0.005	0.001	0.00025
Nitrogen Oxides (NO_x)(5)	500	100	420	0.006614	2.778	2.778	0.694	0.139
Carbon Monoxide (CO)	500	100	420	0.005754	2.417	2.417	0.604	0.121
Total Volatile Organic Compounds (VOC)(5)	500	100	420	0.000882	0.370	0.370	0.093	0.019
Sulfuric Acid Mist (as H_2SO_4)	500	100	420	0.000001	0.0006	0.0006	1.50E-04	0.00003
1,3-Butadiene	500	100	420	2.77E-07	1.2E-04	1.2E-04	2.91E-05	5.8E-06
Acenaphthene	500	100	420	1.01E-08	4.2E-06	4.2E-06	1.06E-06	2.1E-07
Acenaphthylene	500	100	420	3.59E-08	1.5E-05	1.5E-05	3.77E-06	7.5E-07
Acetaldehyde	500	100	420	5.44E-06	0.002	0.002	5.71E-04	1.1E-04
Acrolein	500	100	420	6.56E-07	2.8E-04	2.8E-04	6.89E-05	1.4E-05
Anthracene	500	100	420	1.33E-08	5.6E-06	5.6E-06	1.39E-06	2.8E-07
Benz(a)anthracene	500	100	420	1.19E-08	5.0E-06	5.0E-06	1.25E-06	2.5E-07
Benzene	500	100	420	6.62E-06	0.003	0.003	6.95E-04	1.4E-04
Benzo(a)pyrene	500	100	420	1.33E-09	0.000	0.000	1.40E-07	2.8E-08
Benzo(b)fluoranthene	500	100	420	7.03E-10	0.000	0.000	7.38E-08	1.5E-08
Benzo(g,h,i)perylene	500	100	420	3.47E-09	0.000	0.000	3.64E-07	7.3E-08
Benzo(k)fluoranthene	500	100	420	1.10E-09	0.000	0.000	1.15E-07	2.3E-08
Chrysene	500	100	420	2.50E-09	0.000	0.000	2.63E-07	5.3E-08
Dibenzo(a,h)anthracene	500	100	420	4.13E-09	0.000	0.000	4.34E-07	8.7E-08
Fluoranthene	500	100	420	5.40E-08	0.000	0.000	5.67E-06	1.1E-06
Fluorene	500	100	420	2.07E-07	0.000	0.000	2.17E-05	4.3E-06
Formaldehyde	500	100	420	8.37E-06	0.004	0.004	8.79E-04	1.8E-04
Indeno(1,2,3-cd)pyrene	500	100	420	2.66E-09	0.000	0.000	2.79E-07	5.6E-08
Naphthalene	500	100	420	6.01E-07	2.5E-04	2.5E-04	6.31E-05	1.3E-05
Phenanathrene	500	100	420	2.09E-07	8.8E-05	8.8E-05	2.19E-05	4.4E-06
Propylene	500	100	420	1.83E-05	0.008	0.008	1.92E-03	3.8E-04
Pyrene	500	100	420	3.39E-08	0.000	0.000	3.56E-06	7.1E-07
Toluene	500	100	420	2.90E-06	0.001	0.001	3.05E-04	6.1E-05
Xylene (mixed isomers)	500	100	420	2.02E-06	0.001	0.001	2.12E-04	4.2E-05
Carbon Dioxide (CO_2 or CO_2e)	500	100	420	1.16	488.7	488.7	122.18	24.4
Methane (CH_4)	500	100	420	4.72E-05	0.020	0.020	0.005	0.001
Nitrous Oxide (N_2O)	500	100	420	9.44E-06	0.004	0.004	9.91E-04	0.0002
CO_2e	500	100	420	--	490.40	490.40	122.60	24.52

CI ICE Tier 3	0.15 g/HP-hr	=	0.000331 lbs/HP-hr
CI ICE Tier 3	0.15 g/HP-hr	=	0.000331 lbs/HP-hr
ULSD sulfur content	15 ppm S in Fuel	=	0.000012 lbs/HP-hr
Vendor Information	3.00 g/HP-hr	=	0.006614 lbs/HP-hr
CI ICE Tier 3	2.61 g/HP-hr	=	0.005754 lbs/HP-hr
Vendor Information	0.40 g/HP-hr	=	0.000882 lbs/HP-hr
SO_2 to SO_3 Conversion	1.43E-06 lbs/HP-hr	=	1.43E-06lbs/HP-hr
AP-42 (10/96); Table 3.3-2	3.91E-05 lbs/MMBtu	=	2.77E-07lbs/HP-hr
	1.42E-06 lbs/MMBtu	=	1.01E-08lbs/HP-hr
	5.06E-06 lbs/MMBtu	=	3.59E-08lbs/HP-hr
	7.67E-04 lbs/MMBtu	=	5.44E-06lbs/HP-hr
	9.25E-05 lbs/MMBtu	=	6.56E-07lbs/HP-hr
	1.87E-06 lbs/MMBtu	=	1.33E-08lbs/HP-hr
	1.68E-06 lbs/MMBtu	=	1.19E-08lbs/HP-hr
	9.33E-04 lbs/MMBtu	=	6.62E-06lbs/HP-hr
	1.88E-07 lbs/MMBtu	=	1.33E-09lbs/HP-hr
	9.91E-08 lbs/MMBtu	=	7.03E-10lbs/HP-hr
	4.89E-07 lbs/MMBtu	=	3.47E-09lbs/HP-hr
	1.55E-07 lbs/MMBtu	=	1.10E-09lbs/HP-hr
	3.53E-07 lbs/MMBtu	=	2.50E-09lbs/HP-hr
	5.83E-07 lbs/MMBtu	=	4.13E-09lbs/HP-hr
	7.61E-06 lbs/MMBtu	=	5.40E-08lbs/HP-hr
	2.92E-05 lbs/MMBtu	=	2.07E-07lbs/HP-hr
	1.18E-03 lbs/MMBtu	=	8.37E-06lbs/HP-hr
	3.75E-07 lbs/MMBtu	=	2.66E-09lbs/HP-hr
	8.48E-05 lbs/MMBtu	=	6.01E-07lbs/HP-hr
	2.94E-05 lbs/MMBtu	=	2.09E-07lbs/HP-hr
	2.58E-03 lbs/MMBtu	=	1.83E-05lbs/HP-hr
	4.78E-06 lbs/MMBtu	=	3.39E-08lbs/HP-hr
	4.09E-04 lbs/MMBtu	=	2.90E-06lbs/HP-hr
	2.85E-04 lbs/MMBtu	=	2.02E-06lbs/HP-hr
NA	NA		NA
	NA		NA
40 CFR 98 Table C-2	7.40E+01 kg/MMBtu	=	1.16E+00lbs/HP-hr
	3.00E-03 kg/MMBtu	=	4.72E-05lbs/HP-hr
	6.00E-04 kg/MMBtu	=	9.44E-06lbs/HP-hr

Notes

(1) Sources:
- PM_{10} and CO emission factors based on EPA emission certification for Tier 3 engine
- SO_x based use of ULSD
- NO_x emission factors based CI ICE Tier 23Standard for Nox + NMHC
- VOC emissions provided by vendor
- Spectated organics: AP-42 Emission Factors
- CO2, CH_4 and N_2O emission factors based on 40 CFR 98 Table C-2
- Sulfuric Acid Mist (as H_2SO_4) emissions provided by vendor, based on 10% conversion

(2) Calculated as: Engine Size (HP) **X** Emission Factor (lbs/HP-hr)

(3) Maximum emissions assumed to same as average emissions

(4) Calculated as: Emissions (lbs/hr) **X** Annual Operation (hrs/yr) ÷ 2,000 lbs/ton

(5) NOx emissions are depicted at a rate of 3.0 g/hp-hr for conservative permitting purposes; however, NOx + NMHC emissions from the unit will not exceed 3.0 g/hp-hr, as specified in 40 CFR 60 Subpart IIII.

(6) CO2e emissions = CO2 Emissions *CO2 GWP + CH4 Emissions * CH4 GWP + N2O Emissions * N2O GWP

Appendix A: ATSD Emission Calculations
Fugitive Dust Emissions - Paved Roads

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

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)
Ammonia Delivery Truck (2/wk;one-way)	1.0	0.3	0.3	41.0	11.7	2112	0.400	0.1	41.7
Fuel Oil Delivery Truck (2/yr; one-way)	1.0	0.0	0.0	41.0	0.2	2112	0.400	0.0	0.8
Tradesmen/Delivery Trucks (15/wk; one-way)	3.0	2.1	6.4	4.5	28.9	2112	0.400	2.6	938.6
Ammonia Delivery Truck (2/wk;one-way)	1.0	0.3	0.3	16.0	4.6	2112	0.400	0.1	41.7
Fuel Oil Delivery Truck (2/yr; one-way)	1.0	0.0	0.0	16.0	0.1	2112	0.400	0.0	0.8
Tradesmen/Delivery Trucks (15/wk; one-way)	3.0	2.1	6.4	2.6	16.7	2112	0.400	2.6	938.6
		Totals	**13.4**		**62.2**			**5.4**	**1962.2**

Average Vehicle Weight Per Trip = 4.6 tons/trip
Average Miles Per Trip = 0.40 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 =	4.6	4.6	4.6	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 = 125 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 =	0.415	0.083	0.0204	lb/mile
Mitigated Emission Factor, Eext =	0.380	0.076	0.0186	lb/mile

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)
Ammonia Delivery Truck (2/wk;one-way)	0.01	0.00	0.00
Fuel Oil Delivery Truck (2/yr; one-way)	0.00	0.00	0.00
Tradesmen/Delivery Trucks (15/wk; one-way)	0.18	0.04	0.01
Ammonia Delivery Truck (2/wk;one-way)	0.01	0.00	0.00
Fuel Oil Delivery Truck (2/yr; one-way)	0.00	0.00	0.00
Tradesmen/Delivery Trucks (15/wk; one-way)	0.18	0.04	0.01
Totals	**0.37**	**0.07**	**0.02**

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: ATSD Emission Calculations
Screening Modeling - 185-foot Stack

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

			1	2	3	4	5	6	7	8	9	10	11					
Operating Scenarios			-15°F, Gas fuel, 1 GT @ 100% load	-15°F, Gas fuel, 1 GT @ 75% load	-15°F, Gas fuel, 1 GT @ 62.0021% load	59°F, Gas fuel, 1 GT @ 100% load, EC on	59°F, Gas fuel, 1 GT @ 100% load	59°F, Gas fuel, 1 GT @ 75% load	59°F, Gas fuel, 1 GT @ 29.3864% load	105°F, Gas fuel, 1 GT @ 100% load, EC on	105°F, Gas fuel, 1 GT @ 100% load	105°F, Gas fuel, 1 GT @ 75% load	105°F, Gas fuel, 1 GT @ 35.6867% load		Cold Start	Warm Start	Hot Start	Shutdown
Stack Parameters																		
Stack Temperature	°F		183.7	166.8	163.9	182.5	181.7	168.7	155.8	210.1	203.4	193.7	177.9		156.0	156.0	156.0	156.0
Stack Mass flow, including Permitting Margin, per stack	lb/h		6886700	5541700	5029900	6799200	6804700	5486500	3661000	6520600	5985700	5037600	3628400					
Margined exhaust vol flow (incl. permitting margin)	Mft3/h		116.22	91.069	82.212	115.03	114.86	90.7	59.1	116.28	105.45	87.372	61.278					
Margined exhaust vol flow (incl. permitting margin)	acfm		1937000	1517816.667	1370200	1917166.667	1914333.333	1511666.667	985000	1938000	1757500	1456200	1021300		974130	917470	789540	842540
Margined exhaust vol flow (incl. permitting margin) (24-hr and annual)	acfm		1937000	1517816.667	1370200	1917166.667	1914333.333	1511666.667	985000	1938000	1757500	1456200	1021300		985000	985000	985000	985000
Normalized Screening Model Impacts [(ug/m3)/(g/s)]																		
1-hour (max) - For 1-hour CO			1.09571	1.41147	1.51718	1.11125	1.11655	1.4049	1.80864	0.97805	1.09914	1.3132	1.68754		1.81548	1.85635	1.95206	1.91233
1-hour (annual max averaged over 5 years) - For 1-hour NO2			0.58934	0.74748	0.90227	0.59348	0.59496	0.74546	1.29573	0.55581	0.58749	0.70553	1.13672		1.30961	1.39156	1.63045	1.51544
8-hour (max) - For 8-hour CO			0.43749	0.5923	0.65337	0.4445	0.44692	0.58833	1.04477	0.38735	0.43799	0.53845	0.90286		1.10622	1.13171	1.38751	
24-hour (max) - For PM10 24-hour			0.1897	0.23874	0.26605	0.19195	0.1927	0.23759	0.41474	0.17367	0.19059	0.22287	0.32815		0.42154	0.42154	0.42154	
24-hour (annual max averaged over 5 years) - For 24-hr PM2.5			0.15677	0.21089	0.23416	0.15923	0.16011	0.20939	0.35179	0.13854	0.15603	0.19087	0.29895		0.3524	0.3524	0.3524	
Annual (max of 5 years) - for PM10 Annual and NO2 Annual			0.01798	0.02549	0.02865	0.01831	0.01842	0.02528	0.04175	0.01566	0.01792	0.02271	0.03473		0.03915	0.03915	0.03915	
Annual (averaged over 5 years) - For annual PM2.5			0.01515	0.02167	0.02451	0.01542	0.01552	0.02149	0.03657	0.01315	0.01504	0.01921	0.03035		0.03653	0.03653	0.03653	
Max Hourly Emission Rates (lb/hr)																		
NO2			30.90	12.90	30.40	10.60	29.60	29.10	10.50	29.00	27.40	10.20	27.40		11	8	5	2
CO			18.80	7.80	18.50	6.40	18.00	17.70	6.40	17.70	16.70	6.20	16.70		266	230	209	190
PM10			13.90	8.68	13.80	7.70	13.70	13.60	7.86	13.60	13.30	7.88	13.30		14	14	14	14
PM2.5			13.90	8.68	13.80	7.70	13.70	13.60	7.86	13.60	13.30	7.88	13.30		14	14	14	14
8- Hr Average Emission Rates (lb/hr)																		
NO2			30.90	12.90	30.40	10.60	29.60	29.10	10.50	29.00	27.40	10.20	27.40					
CO			18.80	7.80	18.50	6.40	18.00	17.70	6.40	17.70	16.70	6.20	16.70		76	67	154	
PM10			13.90	8.68	13.80	7.70	13.70	13.60	7.86	13.60	13.30	7.88	13.30					
PM2.5			13.90	8.68	13.80	7.70	13.70	13.60	7.86	13.60	13.30	7.88	13.30					
24- Hr Average Emission Rates (lb/hr)																		
NO2			30.90	12.90	30.40	10.60	29.60	29.10	10.50	29.00	27.40	10.20	27.40					
CO			18.80	7.80	18.50	6.40	18.00	17.70	6.40	17.70	16.70	6.20	16.70					
PM10			13.90	8.68	13.80	7.70	13.70	13.60	7.86	13.60	13.30	7.88	13.30		13.9	13.8	13.7	
PM2.5			13.90	8.68	13.80	7.70	13.70	13.60	7.86	13.60	13.30	7.88	13.30		13.9	13.8	13.7	
Annual Average Emission Rates (lb/hr)																		
NO2			30.90	12.90	30.40	10.60	29.60	29.10	10.50	29.00	27.40	10.20	27.40		38.1	38.1	38.1	
CO			18.80	7.80	18.50	6.40	18.00	17.70	6.40	17.70	16.70	6.20	16.70					
PM10			13.90	8.68	13.80	7.70	13.70	13.60	7.86	13.60	13.30	7.88	13.30		38.1	38.1	38.1	
PM2.5			13.90	8.68	13.80	7.70	13.70	13.60	7.86	13.60	13.30	7.88	13.30		38.1	38.1	38.1	
Hourly Emission Rates (g/s)																		
NO2			3.89	1.63	3.8304	1.34	3.73	3.67	1.32	3.65	3.45	1.29	3.45		1.4473	1.0453	0.6048	0.2602
CO			2.37	0.98	2.33	0.81	2.27	2.23	0.81	2.23	2.10	0.78	2.10		33.4800	28.9800	26.3844	23.9450
PM10			1.75	1.09	1.74	0.97	1.73	1.71	0.99	1.71	1.68	0.99	1.68		1.7064	1.7010	1.7325	1.7161
PM2.5			1.75	1.09	1.74	0.97	1.73	1.71	0.99	1.71	1.68	0.99	1.68		1.7064	1.7010	1.7325	1.7161
8- Hr Average Emission Rates (g/s)																		
NO2			3.89	1.63	3.83	1.34	3.73	3.67	1.32	3.65	3.45	1.29	3.45					
CO			2.37	0.98	2.33	0.81	2.27	2.23	0.81	2.23	2.10	0.78	2.10		9.6029	8.3922	19.4657	
PM10			1.75	1.09	1.74	0.97	1.73	1.71	0.99	1.71	1.68	0.99	1.68					
PM2.5			1.75	1.09	1.74	0.97	1.73	1.71	0.99	1.71	1.68	0.99	1.68					
24- Hr Average Emission Rates (g/s)																		
NO2			3.89	1.63	3.83	1.34	3.73	3.67	1.32	3.65	3.45	1.29	3.45					
CO			2.37	0.98	2.33	0.81	2.27	2.23	0.81	2.23	2.10	0.78	2.10					
PM10			1.75	1.09	1.74	0.97	1.73	1.71	0.99	1.71	1.68	0.99	1.68		1.7477	1.7407	1.7311	
PM2.5			1.75	1.09	1.74	0.97	1.73	1.71	0.99	1.71	1.68	0.99	1.68		1.7477	1.7407	1.7311	
Annual Average Emission Rates (g/s)																		
NO2			3.89	1.63	3.83	1.34	3.73	3.67	1.32	3.65	3.45	1.29	3.45		4.7998	4.7998	4.7998	
CO			2.37	0.98	2.33	0.81	2.27	2.23	0.81	2.23	2.10	0.78	2.10					
PM10			1.75	1.09	1.74	0.97	1.73	1.71	0.99	1.71	1.68	0.99	1.68		4.7998	4.7998	4.7998	
PM2.5			1.75	1.09	1.74	0.97	1.73	1.71	0.99	1.71	1.68	0.99	1.68		4.79976	4.80	4.80	
Screening Modeling Estimated Impacts (ug/m3)		SIL																
NO2 1-hr		7.5	2.29	1.21	3.46	0.79	2.22	2.73	1.71	2.03	2.03	0.91	3.92		1.90	1.45	0.99	
NO2 Annual		1.0	0.07	0.04	0.11	0.02	0.07	0.09	0.06	0.06	0.06	0.03	0.12		0.19	0.19	0.19	
CO 1-hr		2000.0	2.60	1.39	3.54	0.90	2.53	3.13	1.46	2.18	2.31	1.03	3.55		60.78	53.80	51.50	45.79
CO 8-hr		500	1.04	0.58	1.52	0.36	1.01	1.31	0.84	0.86	0.92	0.42	1.90		10.62	9.50	27.01	
PM10 24-hr		5	0.33	0.26	0.46	0.19	0.33	0.41	0.41	0.30	0.32	0.22	0.55		0.72	0.72	0.73	
PM10 Annual		1	0.03	0.03	0.05	0.02	0.03	0.04	0.04	0.03	0.03	0.02	0.06		0.19	0.19	0.19	
PM2.5 24-hr		1.2	0.27	0.23	0.41	0.15	0.28	0.36	0.35	0.24	0.26	0.19	0.50		0.62	0.61	0.61	
PM2.5 Annual		0.3	0.03	0.02	0.04	0.01	0.03	0.04	0.04	0.02	0.03	0.02	0.05		0.18	0.18	0.18	

Appendix A: ATSD Emission Calculations
Ancillary Equipment Modeling Parameters

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Ancillary Equipment		Auxiliary Boiler	Emergency Generator	Emergency Fire Pump
Stack Parameters				
Stack Temperature	°F	300.0	900.0	850.0
exhaust vol flow	acfm	26700	17300	2200
Max Hourly Emission Rates (lb/hr)				
NO2		3.55	0.24	0.03
CO		3.55	11.58	2.42
PM10		0.72	0.67	0.14
PM2.5		0.72	0.67	0.14
8- Hr Average Emission Rates (lb/hr)				
NO2		3.55	21.29	2.78
CO		3.55	11.58	2.42
PM10		0.72	0.67	0.14
PM2.5		0.72	0.67	0.14
24- Hr Average Emission Rates (lb/hr)				
NO2		3.55	0.89	0.12
CO		3.55	0.21	0.10
PM10		0.72	0.03	0.01
PM2.5		0.72	0.03	0.01
Annual Average Emission Rates (lb/hr)				
NO2		3.55	0.24	0.03
CO		3.55	0.13	0.03
PM10		0.72	0.01	0.00
PM2.5		0.72	0.01	0.00
Hourly Emission Rates (g/s)				
NO2		0.4473	0.0306	0.0040
CO		0.4473	1.4587	0.3045
PM10		0.0907	0.0838	0.0175
PM2.5		0.0907	0.0838	0.0175
8- Hr Average Emission Rates (g/s)				
NO2		0.4473	2.6827	0.3500
CO		0.4473	1.4587	0.3045
PM10		0.0907	0.0838	0.0175
PM2.5		0.0907	0.0838	0.0175
24- Hr Average Emission Rates (g/s)				
NO2		0.4473	0.1118	0.0146
CO		0.4473	0.0270	0.0127
PM10		0.0907	0.0035	0.0007
PM2.5		0.0907	0.0035	0.0007
Annual Average Emission Rates (g/s)				
NO2		0.4473	0.0306	0.0040
CO		0.4473	0.0167	0.0035
PM10		0.0907	0.0010	0.0002
PM2.5		0.0907	0.0010	0.0002

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Part 70 Significant Permit Modification and PSD/Significant Source Modification

Source Description and Location

Source Name:	**Maple Creek Energy LLC**
Source Location:	**W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849**
County:	**Sullivan**
SIC Code:	**4911 (Electric Services)**
Operation Permit No.:	**T 153-45909-00056**
Operation Permit Issuance Date:	**June 19, 2023**
Significant Source Modification No.:	**153-49550-00056**
Significant Permit Modification No.:	**153-50217-00056**
Permit Reviewer:	**Tamera Wessel**

Source Definition

The following plants are considered in the source determination:

(a) Plant 1, Maple Creek Energy 1, is located at W CR 1040 N 0.5 miles South and SR 63 0.4 miles West, Fairbanks, Indiana 47849, Source ID: 153-00056. Plant 1 is a natural gas-fired combined cycle system.

(b) Plant 2, Maple Creek Energy 2, is/will be located at W CR 1040 N 0.5 miles South and SR 63 0.4 miles West, Fairbanks, Indiana 47849, Source ID: Pending. Plant 2 is a natural gas-fired combined cycle system.

IDEM's Nonrule Policy Documents Air-005 applies to the definition of "major source" in 326 IAC 2-7-1(22). IDEM's Nonrule Policy Document Air-006 provides additional policy guidance to permitting on-site contractors. All of IDEM's nonrule policy documents are available at https://www.in.gov/idem/resources/nonrule-policies/effective-nonrule-policies/ on IDEM's website.

IDEM, OAQ has examined whether these plants are part of the same Part 70 major source. The term "major source" is defined at 326 Indiana Administrative Code 2-7-1(22). The Indiana Administrative Code is available at http://www.in.gov/legislative/iac/iac_title?iact=326 on the Internet. In order for these plants to be considered as a major source under 326 IAC 2-7-1(22)(B) and (C), all three of the following criteria must be met:

(a) The plants must have common ownership and/or control;

(b) The plants must have the same two-digit Standard Industrial Classification (SIC) Code or one must serve as a support facility to the other; and

(c) The plants must be located on the same, contiguous or adjacent properties.

First Criteria - Common Ownership or Control:
The first criteria to be considered is whether these plants are under common ownership or control. NPD Air-005 states:

Common ownership may exist in several forms.

- If a third party has ownership of fifty-one percent (51%) or more in each of two (2) or more entities, common ownership exists.
- If two (2) or more entities share common corporate officers, in whole or in substantial part, who are responsible for the day-to-day operations of the entities, common ownership exists.
- If one entity has fifty-one percent (51%) or greater ownership of another entity, common ownership exists.

Each Plant will be owned by a separate Project Company. The Project Companies will have common parent ownership by AL Advanced Power DevCo TopCo LLC prior to the start of construction. After the start of construction, it is anticipated that the Plants may have different ownership structures. However, at the time of the construction permit issuance, the first criteria of common ownership is met.

Second Criteria - Common SIC Code or Support Facility:
The second criteria is whether either of the plants have a common two-digit Standard Industrial Classification (SIC) Code or if one plant serves as a support facility for the other plant. The Standard Industrial Classification Manual of 1987 sets out how to determine the proper SIC Code for each type of business. More information about SIC Codes is available at https://www.osha.gov/data/sic-manual on the Internet. The SIC Code is determined by looking at the principal product or activity of each plant.

The two-digit Standard Industrial Classification (SIC) Code for both plants is Major Group 49: Electric, Gas, and Sanitary Services. More specifically, both plants have a SIC Code of 4911 Electric Services.

Third Criteria - Same, Contiguous, or Adjacent Properties:
The third and last criteria of the major source definition is whether the plants are on the same, contiguous or adjacent properties. Plants located on properties that share a common property border are contiguous.

The plants will be located on the same 176-acre property. Therefore, the third criteria of the major source definition is met.

Source Determination - Final Conclusion Under 326 IAC 2-7-1(22)(B) and (C):
IDEM, OAQ finds that the plants meet all three criteria of the major source definition. Therefore, the plants are part of the same Part 70 major source.

An Administrative Part 70 Permit will be issued to Maple Creek Energy II LLC (Source ID: 153-00064) solely for administrative purposes.

Existing Approvals

The source was issued Part 70 Operating Permit No. T153-45909-00056 on June 19, 2023. The source has since received the following approvals:

(a) Administrative Amendment No. 153-48358-00056, issued on October 21, 2024

County Attainment Status

The source is located in Sullivan 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 SO2 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 PM2.5 standard.
$PM_{2.5}$	Unclassifiable or attainment effective December 13, 2009, for the 2006 24-hour PM2.5 standard.
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Unclassifiable or attainment effective January 29, 2012, for the 2010 NO2 standard.
Pb	Unclassifiable or attainment effective December 31, 2011, for the 2008 lead standard.

(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. Sullivan 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) $PM_{2.5}$
Sullivan 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
Sullivan 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 plant of more than 250 million Btu/hr 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	GHG	Single HAP[3]	Total HAPs
Total PTE of Entire Source Including Fugitives*	72.29	72.29	72.29	32.55	147.38	37.27	120.49	2,304,359	<10	10.08
Title V Major Source Thresholds	NA	100	100	100	100	100	100	NA	10	25
PSD Major Source Thresholds	100	100	100	100	100	100	100	75,000	--	--

[1]Under the Part 70 Permit program (40 CFR 70), PM_{10} and $PM_{2.5}$, not particulate matter (PM), are each considered as a "regulated air pollutant."
[2]$PM_{2.5}$ listed is direct $PM_{2.5}$.
[3]Single highest source-wide HAP
*Fugitive HAP emissions are always included in the source-wide emissions.

(a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because a PSD regulated pollutant(s), NOx, CO, and GHGs, 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 not a major source of HAP, as defined in 40 CFR 63.2, because HAP emissions are less than ten (10) tons per year for any single HAP and less than twenty-five (25) tons per year of a combination of HAPs.

(c) These emissions are based on the TSD of TV NSC No. T153-45909-00056, issued on June 19, 2023.

Description of Proposed Modification

The Office of Air Quality (OAQ) has reviewed an application submitted by Maple Creek Energy LLC on September 5, 2025, relating to the removal of the Siemens Model SCC6-9000HL Turbine option and adjusting potential emissions calculations for the remaining turbine due to updated emissions data provided by the turbine manufacturer.

The Part 70 Operating Permit No. T153-45909-00056 issued to Maple Creek Energy LLC on June 19, 2023 contained the requirements and details for two possible options of a turbine to be installed (only one of which would be constructed). The Permittee has determined the turbine they would like to install and therefore have requested to remove all requirements and references to the unselected unit. Additionally, Maple Creek Energy LLC has requested to revise PM, PM10 and PM2.5 emissions limits as a result of updated emissions data provided by the turbine manufacturer. As the units granted permission to construct in Part 70 Operating Permit No. T153-45909-00056 have not been built, these units will require reapproval to construct.

The following is a list of the new and modified emission units and pollution control devices:

(a) One (1) natural gas-fired combined cycle system, identified as CTG-01, approved in 2026 for construction, with a maximum heat input capacity of 4,253 MMBtu per hour, equipped with a GE combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG) and one air-cooled condenser (ACC), using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.

Under 40 CFR 60, Subpart KKKK, CTG-01 is an affected facility because it was constructed after February 18, 2005, has a maximum heat input capacity of greater than 10 MMBtu/hr, and is a stationary combustion turbine (CTG).

Under 40 CFR 60, Subpart TTTTa, CTG-01 was constructed after May 23, 2023, has a base load rating greater than 250 MMBtu/hr of fossil fuel, and serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system, and is an affected unit.

Ancillary Equipment:

(b) One (1) natural gas-fired auxiliary boiler, identified as AUX, equipped with ultra-low-NOx burners, approved in 2026 for construction, with a rated maximum heat input capacity of 96 MMBtu per hour, and exhausting to stack AUX.

Under 40 CFR 60, Subpart Dc, AUX is an affected facility because it was constructed after June 9, 1989, has a maximum design heat input capacity of less than 100 MMBtu/hr, but greater than 10 MMBtu/hr, and is considered a small steam generating unit.

(c) One (1) diesel-fired emergency generator using ultra-low-sulfur-distillate (ULSD), identified as EG, approved in 2026 for construction, with a maximum output rating of 2,012 horsepower (hp) and exhausting to stack EG.

Under 40 CFR 60, Subpart IIII, EG is an affected facility because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and is not a fire pump engine.

Under 40 CFR 63, Subpart ZZZZ, EG is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

(d) One (1) diesel-fired emergency fire pump engine using ultra-low-sulfur-distillate (ULSD), identified as FP, approved in 2026 for construction, with a maximum output rating of 420 horsepower (hp), and exhausting to stack FP.

Under 40 CFR 60, Subpart IIII, FP is an affected facility because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, and was manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Under 40 CFR 63, Subpart ZZZZ, FP is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

As part of this permitting action, the following emission units are being removed from the permit:

Option 1: Siemens Model SCC6-9000HL Turbine

(a1) One (1) natural gas-fired combined cycle system, identified as CTGA, approved in 2026 for construction, with a maximum heat input capacity of 3,800 MMBtu per hour, equipped with a Siemens combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG), using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.

Under 40 CFR Part 60, Subpart KKKK, this unit considered an affected facility.
Under 40 CFR Part 60, Subpart TTTT, this unit is considered an affected facility.

Project Aggregation

Project 1: Maple Creek Energy LLC, Significant Source Modification No. 153-49550-00056, issuance pending.

Project 2: Maple Creek Energy II LLC, Significant Source Modification No. 153-49555-00064, issuance pending.

Maple Creek II has been determined to be one source with Maple Creek Energy. Therefore, these projects are aggregated as one project. Since Maple Creek Energy has not yet begun construction, the emission units must go through PSD BACT review.

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.

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	H_2SO_4	GHG	Single HAP[3]	Total HAPs
Total PTE of Entire Source (Plant 1) Including Fugitives*	**74.88**	**74.58**	**74.53**	**33.01**	**>100**	**62.03**	**>100**	**21.96**	**>75,000**	**4.06**	**10.70**
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100	NA	10	25
PSD Major Source Thresholds	100	100	100	100	100	100	100	100	75,000	--	--

[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."

	Source-Wide Emissions Prior to Modification (ton/year)										
	PM[1]	PM_{10}[1]	$PM_{2.5}$[1, 2]	SO_2	NO_X	VOC	CO	H_2SO_4	GHG	Single HAP[3]	Total HAPs

[2]$PM_{2.5}$ listed is direct $PM_{2.5}$.
[3]Single highest source-wide HAP formaldehyde.
*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), NOx, CO, and GHGs, 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 not a major source of HAP, as defined in 40 CFR 63.2, because HAP emissions are less than ten (10) tons per year for any single HAP and less than twenty-five (25) tons per year of a combination of HAPs.

(c) These emissions are based on the TSD of Part 70 Permit No. T153-45909-00056, issued on June 19, 2023.

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[1]**	**PM_{10}[1]**	**$PM_{2.5}$[1]**	**SO_2**	**NO_X**	**VOC**	**CO**	**H_2SO_4**	**GHG**	**Single HAP[3]**	**Total HAPs**
CTG-01 (Worst Case)	59.57	59.57	59.57	28.47	136.12	36.14	112.69	19.27	2,065,094	3.85	9.41
Auxiliary Boiler (AUX)	3.15	3.15	3.15	0.59	15.55	1.45	15.55	0.059	49,247	0.03	0.77
Emergency Generator (EG)	0.17	0.17	0.17	0.006	5.32	0.35	2.89	negl.	625.26	--	0.02
Emergency Fire Pump (FP)	0.03	0.03	0.03	0.00	0.69	0.09	0.60	negl.	122.60	--	4.81E-03
Tanks	--	--	--	--	--	0.50	--	--	--	--	--
Paved Roads	0.37	0.07	0.02	--	--	--	--	--	--	--	--
Total PTE Before Controls of the New Emission Units:	**63.30**	**63.00**	**62.94**	**29.07**	**157.68**	**62.03**	**184.76**	**19.33**	**2,115,089**	**3.88**	**10.20**
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100	NA	10	25

[1]$PM_{2.5}$ listed is direct $PM_{2.5}$.
[2]Single highest HAP is formaldehyde.

Appendix A of this TSD reflects the detailed potential emissions 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)(2), a Significant Source Modification is required because this modification is subject to 326 IAC 8-1-6.

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.

(b) Approval to Operate

The potential to emit (as defined in 326 IAC 2-7-1(28)) of NOx and CO from the plant (Plant 1, MCE I LLC) are each equal to or greater than the Title V major source threshold levels. Therefore, the plant is subject to the provisions of 326 IAC 2-7 and will be issued an Administrative Part 70 Operating Permit.

Permit Level Determination – PSD Emissions Increase

(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) 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.

$ATP_{(\text{new unit})} = PTE_{(\text{new unit})} – \text{Baseline Emissions}_{(\text{new unit})}$

See Appendix A of this Technical Support Document for detailed emission calculations.

Project Emissions Increase (tons/year)									
Process/Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**NO_X**	**VOC**	**CO**	**H_2SO_4**	**GHGs**
CTG-01 (Worst Case)	59.57	59.57	59.57	28.47	136.12	36.14	112.69	19.27	2,065,094
Auxiliary Boiler (AUX)	3.15	3.15	3.15	0.59	15.55	1.45	15.55	0.059	11,244
Emergency Generator (EG)	0.17	0.17	0.17	0.006	5.32	0.35	2.89	negl.	125.05
Emergency Fire Pump (FP)	0.03	0.03	0.03	0.00	0.69	0.09	0.60	negl.	24.52
Tanks	0	0	0	0	0	0.50	0	0	0
Paved Roads	0.37	0.07	0.02	0	0	0	0	0	0
Project Emissions Increase	**63.30**	**63.00**	**62.94**	**29.07**	**157.68**	**62.03**	**184.76**	**19.33**	**2,076,487**
Significant Levels	25	15	10	40	40	40	100	7	75,000 CO_2e

Project Emissions Increase (tons/year)									
Process/Emissions Unit	**PM**	**PM_{10}**	**$PM_{2.5}$***	**SO_2**	**NO_X**	**VOC**	**CO**	**H_2SO_4**	**GHGs**
*PM2.5 listed is direct PM2.5.									

Appendix A of this TSD reflects the detailed potential emissions 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)(2), a Significant Source Modification is required because this modification is subject to 326 IAC 8-1-6.

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.

(b) Approval to Operate

The potential to emit (as defined in 326 IAC 2-7-1(28)) of NOx and CO from the plant (Plant 2, MCE II LLC) are each equal to or greater than the Title V major source threshold levels. Therefore, the plant is subject to the provisions of 326 IAC 2-7 and will be issued an Administrative Part 70 Operating Permit.

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 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**	**H_2SO_4**	**GHG**	**Single HAP[3]**	**Total HAPs**
Total PTE of Plant 1 (MCE I) Including Fugitives*	63.30	63.00	62.94	29.07	>100	62.03	>100	21.96	>75,000	3.88	10.18
Total PTE of Plant 2 (MCE II) Including Fugitives*	60.70	60.40	60.35	28.61	>100	37.06	>100	19.29	>75,000	3.86	9.59
Total PTE of Entire Source Including Fugitives*	**>100**	**>100**	**>100**	**57.67**	**>100**	**99.09**	**>100**	**38.62**	**>75,000**	**7.75**	**19.79**

	Source-Wide Emissions After Issuance (ton/year)										
	PM[1]	PM_{10}[1]	$PM_{2.5}$[1, 2]	SO_2	NO_X	VOC	CO	H_2SO_4	GHG	Single HAP[3]	Total HAPs
Title V Major Source Thresholds	NA	100	100	100	100	100	100	100	NA	10	25
PSD Major Source Thresholds	100	100	100	100	100	100	100	100	75,000	--	--

[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 is formaldehyde.
*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, NOx, CO, and H_2SO_4, has emissions equal to or greater than the PSD major source threshold.

(b) This existing area source of HAP will continue to be an area source of HAP, as defined in 40 CFR 63.2, because HAP emissions will continue to be less than ten (10) tons per year for any single HAP and less than twenty-five (25) tons per year of a combination of HAPs. Therefore, this source is an area source under Section 112 of the Clean Air Act (CAA).

Federal Rule Applicability Determination

Due to the modification at this source, federal rule applicability has been reviewed as follows:

New Source Performance Standards (NSPS):

(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 natural gas-fired auxiliary boiler, identified as AUX, because this boiler has a maximum heat input rate of less than 73 MW (250 MMBtu/hr).

(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 natural gas-fired combined cycle system, identified as CTG-01, because this facility is subject to the requirements of 40 CFR 60, Subpart KKKK, and is therefore exempt from the requirements of Subpart Da, pursuant to § 60.40Da(e).

(c) 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 natural gas-fired auxiliary boiler, identified as AUX, because the natural gas-fired auxiliary boiler has a maximum heat input capacity of less than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/hr)), and is therefore not subject to this subpart, pursuant to § 60.40Da(a)(1).

(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 combined cycle system, identified as CTG-01, because this facility is subject to the requirements of 40 CFR 60, Subpart KKKK, and is therefore exempt from the requirements of Subpart Db, pursuant to § 60.40b(i).

(e) 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 auxiliary boiler, identified as AUX, because the natural gas-fired auxiliary boiler has a maximum heat input capacity of less than 29 megawatts (MW)

(100 million British thermal units per hour (MMBtu/hr)), and is therefore not subject to this subpart, pursuant to § 60.40b(a).

(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 natural gas-fired combined cycle system, identified as CTG-01, because this facility is subject to the requirements of 40 CFR 60, Subpart KKKK, and is therefore exempt from the requirements of Subpart Dc, pursuant to § 60.40c(e).

(g) The natural gas-fired auxiliary boiler, identified as AUX, 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 the natural gas-fired auxiliary boiler (AUX) is a steam generating unit for which construction commenced after June 9, 1989, and has a maximum design heat input capacity of less than 100 MMBtu/hr, but greater than 10 MMBtu/hr. The maximum design heat input capacity of the natural gas-fired auxiliary boiler (AUX) is 96 MMBtu/hr.

The natural gas-fired auxiliary boiler, identified as AUX, is subject to the following portions of Subpart Dc.

60.40c	Applicability and delegation of authority.
60.41c	Definitions.
60.48c(a)(1), (a)(3), (g), and (i)	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 auxiliary boiler, identified as AUX, except as otherwise specified in 40 CFR 60, Subpart Dc.

(h) The requirements of the New Source Performance Standard for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978, 40 CFR 60, Subpart K and 326 IAC 12, are not included in the permit for the six (6) storage tanks, because each of these tanks has a capacity of less than 40,000 gallons, was constructed after May 19, 1978, and does not store petroleum liquids, as defined in § 60.111. Petroleum liquids do not include fuel oil to diesel fuel oils.

(i) The requirements of the New Source Performance Standard for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984, 40 CFR 60, Subpart Ka and 326 IAC 12, are not included in the permit for six (6) storage tanks, because each of these tanks has a capacity of less than 40,000 gallons, was constructed after July 23, 1984, and does not store petroleum liquids, as defined in § 60.111a. Petroleum liquids do not include fuel oil to diesel fuel oils.

(j) The requirements of the New Source Performance Standard for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984, and On or Before October 4, 2023, 40 CFR 60, Subpart Kb and 326 IAC 12, are not included in the permit for six (6) storage tanks, because each of these tanks has a capacity of less than 75 cubic meters (m^3), was constructed after October 4, 2023, and does not store petroleum liquids.

(k) 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 six (6) storage tanks, because although these tanks will be constructed after October 4, 2023, each of the tanks has a storage capacity of less than 20,000 gallons storing volatile organic liquids (VOL) with a maximum true vapor pressure of less than 0.25 psia (1.7 kPa absolute).

(l) 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 combined cycle system, identified as CTG-01, because this facility is subject to a newer subpart (40 CFR 60, Subpart KKKK, NSPS for Stationary Combustion Turbines). Pursuant to § 60.4305(b), stationary combustion turbines that are regulated under subpart KKKK are exempt from the requirements of subpart GG.

(m) The one (1) diesel-fired emergency generator (EG) is subject to the New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII and 326 IAC 12, because this unit is a stationary compression ignition (CI) internal combustion engine (ICE) that will commence construction after July 11, 2005, was manufactured after April 1, 2006, and is not a fire pump engine.

The one (1) diesel-fired emergency generator (EG) is subject to the following portions of Subpart IIII.

60.4200(a)(2)(i), (a)(4), (c)	Am I subject to this subpart?
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(a)	What is the deadline for importing or installing stationary CI ICE produced in previous model years?
60.4209(a)	What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?
60.4211(a), (c), (f), (g)(3)	What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?
60.4214(b) and (d)	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 5	Labeling and Recordkeeping Requirements for New Stationary Emergency Engines
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 one (1) diesel-fired emergency generator (EG) except as otherwise specified in 40 CFR 60, Subpart IIII.

(n) The one (1) diesel-fired emergency fire pump engine (FP) is subject to the New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII and 326 IAC 12, because this unit is a fire pump engine that will commence construction after July 1, 2006.

The one (1) diesel-fired emergency fire pump engine (FP) is subject to the following portions of Subpart IIII.

60.4200(a)(2)(ii), (a)(4), and (c)	Am I subject to this subpart?
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?
60.4209(a)	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?
60.4218	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 4	Emission Standards for Stationary Fire Pump Engines
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 one (1) diesel-fired emergency fire pump engine (FP) except as otherwise specified in 40 CFR 60, Subpart IIII.

(o) The natural gas-fired combined cycle system, identified as CTG-01, is subject to the New Source Performance Standards for Stationary Combustion Turbines, 40 CFR 60, Subpart KKKK and 326 IAC 12, because the stationary combustion turbine (CTG) has a maximum heat input capacity of greater than 10 MMBtu per hour and will commence construction after February 18, 2005.

The natural gas-fired combined cycle system, identified as CTG-01 is subject to the following portions of Subpart KKKK:

60.4300	What is the purpose of this subpart?
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(b)	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?
60.4360	How do I determine the total sulfur content of the turbine's combustion fuel?
60.4365(a)	How can I be exempted from monitoring the total sulfur content of the fuel?
60.4375(a)	What reports must I submit?

60.4380(b) and (c)	How are excess emissions and monitor downtime defined for NOX?
60.4385	How are excess emissions and monitoring downtime defined for SO2?
60.4395	When must I submit my reports?
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 combined cycle system, identified as CTG-01, except as otherwise specified in 40 CFR 60, Subpart KKKK.

(p) 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 combined cycle system, identified as CTG-01, because although this facility is a stationary turbine, it will not commence construction before May 23, 2023, pursuant to § 60.5508.

(q) The natural gas-fired combined cycle system, identified as CTG-01, is 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 this facility is a stationary combustion turbine that will commence construction after May 23, 2023, has a base load rating greater than 250 MMBtu per hour of fossil fuel, and serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

The natural gas-fired combined cycle system, identified as CTG-01, is subject to the following portions of Subpart TTTTa.

60.5508a	What is the purpose of this subpart?
60.5509a(a)	Am I subject to this subpart?
60.5515a	Which pollutants are regulated by this subpart?
60.5520a(a) and (b)	What CO_2 emissions standard must I meet?
60.5525a(a)(1), (b), (c)(1), (c)(3)(i)	What are my general requirements for complying with this subpart?
60.5535a(a), (c)(1) through (4), (d)(1)	How do I monitor and collect data to demonstrate compliance?
60.5540a	How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?
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 CTG-01 except as otherwise specified in 40 CFR 60, Subpart TTTTa.

(r) The requirements of the New Source Performance Standard for Greenhouse Gas Emissions for Electric Utility Generating Units, 40 CFR 60, Subpart UUUUb and 326 IAC 12, are not included in the permit for the natural gas-fired combined cycle system, identified as CTG-01, because this subpart requires the Governor of a State in the contiguous United States with one or more designated facilities to submit a State plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart. Therefore, this source is not subject to this subpart.

(s) There are no other New Source Performance Standards (40 CFR Part 60) and 326 IAC 12 included in the permit for this proposed new source.

National Emission Standards for Hazardous Air Pollutants (NESHAP):

(a) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Tanks - Level 1, 40 CFR 63, Subpart OO and 326 IAC 20-35 are not included in the permit for the six (6) storage tanks, since these tanks are not subject to another subpart of 40 CFR 60, 61, or 63.

(b) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Storage Vessels (Tanks) - Control Level 2, 40 CFR 63, Subpart WW and 326 IAC 20-43 are not included in the permit for six (6) storage tanks, since these tanks are not subject to any subpart that references the use of subpart WW for air emission control.

(c) 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 natural gas-fired combined cycle system, since this source is not a major source of HAPs.

(d) The diesel-fired emergency generator and the diesel-fired emergency fire pump engine are both subject to the National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ and 326 IAC 20-82, because each of these units are considered a new (construction commenced on or after June 12, 2006) stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

The units subject to this rule include the following:

(1) One (1) diesel-fired emergency generator using ultra-low-sulfur-distillate (ULSD), identified as EG, approved in 2025 for construction, with a maximum output rating of 2,012 horsepower (hp), using no control, and exhausting to stack EG.

(2) One (1) diesel-fired emergency fire pump engine using ultra-low-sulfur-distillate (ULSD), identified as FP, approved in 2025 for construction, with a maximum output rating of 420 horsepower (hp), using no control, and exhausting to stack FP.

The diesel-fired emergency generator and the diesel-fired emergency fire pump engine are subject to the following portions of Subpart ZZZZ:

63.6580	What is the purpose of subpart ZZZZ?
63.6585	Am I subject to this subpart?
63.6590(a)(2)(iii) and (c)(1)	What parts of my plant does this subpart cover?
63.6595(a)(7)	When do I have to comply with this subpart?
63.6665	What parts of the General Provisions apply to me?
63.6670	Who implements and enforces this subpart?
63.6675	What definitions apply to this subpart?

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 and the diesel-fired emergency fire pump engine except as otherwise specified in 40 CFR 63, Subpart ZZZZ.

(e) The requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD and 326 IAC 20-95 are not included in the permit for the natural gas-fired auxiliary boiler (AUX), since this source is not a major source of HAP.

(f) 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 natural gas-fired auxiliary boiler (AUX), since this boiler is a gas-fired boiler, and is not subject to this subpart pursuant to § 63.11195(e).

(g) 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 new source.

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)
CTG-01 / NO_X	SCR	326 IAC 2-2-3	≥ 100	< 100	N [1]	--
CTG-01 / VOC	OC	326 IAC 8-1-6	< 100	--	N [2]	--
CTG-01 / CO	OC	326 IAC 2-2-3	≥ 100	≥ 100	N [1]	--

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.

PM* For limitations under 326 IAC 6-3-2, 326 IAC 6.5, and 326 IAC 6.8, IDEM OAQ uses PM as a surrogate for the regulated air pollutant PM10. Therefore, uncontrolled PTE and controlled PTE reflect the emissions of the regulated air pollutant PM10.

N [1] A NO_X and CO CEMS is required under 326 IAC 3-5 and 326 IAC 2-2-3 for this unit. This CEMS is 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.

N [2] CAM does not apply for VOC because the uncontrolled PTE of VOC is less than the major source threshold.

Controls: SCR = Selective Catalytic Reduction, OC = Oxidation Catalyst

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 not applicable to any of the units as part of this new source construction permit.

Federal Rule Applicability Determination
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 combined cycle system, identified as CTG-01, is 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 combined cycle system, identified as CTG-01.

Pursuant to 40 CFR 97.804(a)(1), the natural gas-fired combined cycle system, identified as CTG-01, is 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 combined cycle system, identified as CTG-01.

Pursuant to 40 CFR 97.604(a)(1), the natural gas-fired combined cycle system, identified as CTG-01, is 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 combined cycle system, identified as CTG-01.

Transport Rule Monitoring Provisions

The emission unit description identified as XXXX is 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.

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 2-2 (PSD) and 326 IAC 2-3 (Emission Offset)
PSD applicability is discussed under the PTE of the Entire Source After Issuance section of this document.

PSD BACT Limits

Combined-Cycle Combustion Turbine (CTG-01)
Pursuant to 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)) and 326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbine (CTG-01), the Permittee shall comply with the following:

(a) CTG-01 shall combust pipeline-quality natural gas.

(b) PM, PM_{10}, and $PM_{2.5}$ emissions from CTG-01 shall be limited through the use of good combustion practices.

(c) PM emissions from CTG-01 shall not exceed 0.0058 lb/MMBtu, excluding periods of startup and shutdown.

(d) PM_{10} emissions from CTG-01 shall not exceed 0.0058 lb/MMBtu, excluding periods of startup and shutdown.

(e) $PM_{2.5}$ emissions from CTG-01 shall not exceed 0.0058 lb/MMBtu, excluding periods of startup and shutdown.

(f) The NOx emissions from CTG-01 shall be controlled by a Selective Catalytic Reduction system and dry-low-NOx combustors.

(g) The NOx emissions from CTG-01 shall not exceed 2.0 ppmvd @ 15% O_2 based on a 3-hour average, excluding periods of startup and shutdown.

(h) NOx emissions from CTG-01 shall not exceed 30.9 lb/hr, excluding periods of startup and shutdown.

(i) The VOC emissions from CTG-01 shall be controlled by catalytic oxidation and good combustion practices.

(j) VOC emissions from CTG-01 shall not exceed 0.0013 pounds per MMBtu, excluding periods of startup and shutdown.

(k) VOC emissions from CTG-01 shall not exceed 1.0 ppmvd, excluding periods of startup and shutdown.

(l) The CO emissions from CTG-01 shall be controlled using good combustion practices and an oxidation catalyst.

(m) CO emissions from CTG-01 shall not exceed 2.0 ppmvd @ 15% O2 based on a 3-hr average, excluding periods of startup and shutdown.

(n) CO emissions from CTG-01 shall not exceed 0.0044 pounds per MMBtu, excluding periods of startup and shutdown.

(o) SO_2 and H_2SO_4 from CTG-01 shall be controlled through the use of pipeline-quality natural gas.

(p) SO_2 emissions from CTG-01 shall not exceed 0.0019 lb/MMBtu.

(q) H_2SO_4 emissions from CTG-01 shall not exceed 0.0013 lb/MMBtu.

(r) CO_{2e} emissions from CTG-01 shall not exceed 800 lb/MW-hr (gross) corrected to ISO conditions.

(s) CO_{2e} emissions from CTG-01 shall not exceed 2,065,094 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(t) CO_{2e} emissions from CTG-01 shall be limited through the use of low-carbon fuel (natural gas) with high-efficiency, combined cycle generation.

<u>Startup/Shutdown</u>

(a) The PM, PM_{10}, and $PM_{2.5}$ emissions from the combined cycle combustion turbine stack shall each not exceed 1.9 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

(b) The NOx emissions from the combined cycle combustion turbine stack shall not exceed 35.8 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

(c) The VOC emissions from the combined cycle combustion turbine stack shall not exceed 18.8 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

(d) The CO emissions from the combined cycle combustion turbine stack shall not exceed 52.2 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

<u>Auxiliary Boiler (AUX)</u>

Pursuant to 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler (AUX), the Permittee shall comply with the following:

(a) PM, PM_{10}, and $PM_{2.5}$ emissions from the auxiliary boiler (AUX) shall be controlled through the use of pipeline-quality natural gas.

(b) PM, PM_{10}, and $PM_{2.5}$ emissions from the auxiliary boiler (AUX) shall be controlled through the use of good combustion practices.

(c) Filterable PM emissions from the auxiliary boiler (AUX) shall not exceed 0.0019 lb/MMBtu.

(d) PM_{10} emissions from the auxiliary boiler (AUX) shall not exceed 0.0075 lb/MMBtu.

(e) $PM_{2.5}$ emissions from the auxiliary boiler (AUX) shall not exceed 0.0075 lb/MMBtu.

(f) NOx emissions from the auxiliary boiler (AUX) shall not exceed 0.011 lb/MMBtu.

(g) NOx emissions from the auxiliary boiler (AUX) shall be controlled by an Ultra Low NOx Burner.

(h) CO emissions from the auxiliary boiler (AUX) shall not exceed 0.037 lb/MMBtu.

(i) CO emissions from the auxiliary boiler (AUX) shall be controlled through the use of good combustion practices.

(j) H_2SO_4 emissions from the auxiliary boiler (AUX) shall not exceed 0.00014 lb/MMBtu.

(k) H_2SO_4 emissions from the auxiliary boiler (AUX) shall be controlled through the use of only pipeline quality natural gas.

(l) CO_{2e} emissions from the auxiliary boiler (AUX) shall not exceed 11,244 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(m) CO_{2e} emissions from the auxiliary boiler (AUX) shall be controlled through the use of good combustion practices.

(n) The auxiliary boiler (AUX) shall not exceed 2,000 hours of operation per twelve (12) consecutive month period.

<u>Emergency Generator (EG) and Emergency Fire Pump Engine (FP)</u>

Pursuant to 326 IAC 2-2 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the diesel-fired emergency generator (EG) and the diesel-fired emergency fire pump engine (FP), the Permittee shall comply with the following:

(a) The emissions from the emergency generator (EG) shall not exceed the limits in the table below, through the use of state-of-the-art combustion design.

	PM	PM_{10}	$PM_{2.5}$	NOx + NMHC	CO
Emission Limit (g/hp-hr)	0.15	0.15	0.15	4.8	2.61
Emission Limit (lb/hr)	0.67	0.67	0.67	21.29	11.58

(b) The emissions from the emergency fire pump engine (FP) shall not exceed the limits in the table below, through the use of state-of-the-art combustion design.

	PM	PM_{10}	$PM_{2.5}$	NOx + NMHC	CO
Emission Limit (g/kW-hr)	0.20	0.20	0.20	4.0	3.5
Emission Limit (lb/hr)	0.14	0.14	0.14	2.72	2.38

(c) The sulfur content of diesel fuel burned in the emergency generator (EG) shall not exceed 0.0015%.

(d) The sulfur content of diesel fuel burned in the emergency fire water pump engine (FP) shall not exceed 0.0015%.

(e) The GHG BACT for the emergency generator (EG) shall be as follows:

(1) The use of a good engineering design and fuel-efficient design; and

(2) The CO_2e emissions from EG shall not exceed 125 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(f) The GHG BACT for the emergency fire water pump engine (FP) shall be as follows:

(1) The use of a good engineering design and fuel-efficient design; and

(2) CO_{2e} emissions from the emergency fire pump shall not exceed 24 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

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. Maple Creek Energy II LLC 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.

NAAQs modeling for the appropriate time-averaging periods for PM_{10}, $PM_{2.5}$, SO_2, NOx, VOC, CO, Pb, H_2SO_4, and HAPs was conducted and compared to the respective NAAQs limit. All maximum-modeled concentrations were compared to the respective NAAQS limits. All maximum-modeled concentrations during the five years were below the NAAQS limits and further modeling was not required.

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.

(b) Pursuant to 326 IAC 2-2-5 (Air Quality Impact; Requirements), the source shall comply with the following:

(1) The Permittee shall demonstrate that allowable emissions increases in conjunction with all other applicable emissions increase or reductions (including secondary emissions) will not cause or contribute to air pollution in violation of any:

(A) ambient air quality standard, as designated in 326 IAC 1-3, in any air quality control region; or

(B) applicable maximum allowable increase over the baseline concentration in any area as described in 326 IAC 2-2-6.

See Appendix C to this Technical Support Document (TSD) for the PSD air quality analysis.

326 IAC 2-2-6 (Increment Consumption Requirements)
Pursuant to 326 IAC 2-2-6(a) any demonstration under 326 IAC 2-2-5 shall demonstrate that increased emissions caused by the proposed stationary source will not exceed eighty percent (80%) of the available maximum allowable increases (MAI) over the baseline concentrations of SO2, PM (PM10 and PM2.5), and NOx indicated in 326 IAC 2-2-6(b)(1). PM10, PM2.5, and NOx are emitted and subject to PSD in this proposed permit, Significant Source Modification No. 153-49555-00064 and Administrative Part 70 Permit No. T153-49758-00064.

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 T153-49758-0064.

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 this source will emit less than ten (10) tons per year for a single HAP and less than twenty-five (25) tons per year for a combination of HAPs. Therefore, 326 IAC 2-4.1 does not apply.

326 IAC 2-6 (Emission Reporting)
This source is subject to the requirements of 326 IAC 2-6 (Emission Reporting), since it is required to have an operating permit under 326 IAC 2-7, Part 70 Permit Program. Pursuant to 326 IAC 2-6-3(a)(2), the Permittee shall submit triennially, by July 1, an emission statement covering the previous calendar year in accordance with the compliance schedule in 326 IAC 2-6-3. 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 Sullivan 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 Sullivan 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 Sullivan County) is not subject to the requirements of 326 IAC 6.8-10 because it is not located in Lake County.

326 IAC 24 (Cross-State Air Pollutant Rule (CSAPR) Programs)
See the Cross-State Air Pollutant Rule (CSAPR) section above.

State Rule Applicability – Individual Facilities

Due to this modification, state rule applicability has been reviewed as follows:

Combined Cycle Combustion Turbine

326 IAC 3-5 (Continuous Monitoring of Emissions)
Pursuant to 326 IAC 3-5-1(a)(2), the Combined Cycle Combustion Turbine is subject to the monitoring requirements in 326 IAC 3-5-1(b)(2)(C) because this unit is a fossil fuel-fired steam generator of greater than 100 MMBtu/hr. A continuous monitoring system for NO_X shall be installed, calibrated, operated, and maintained to measure NO_X emissions from stack CTG-01.

326 IAC 6-2-1 (Particulate Emission Limitations for Sources of Indirect Heating)
Pursuant to 326 IAC 6-2-1(g), the Combined Cycle Combustion Turbine is not subject to the provision of 326 IAC 6-2-4 since this unit is not a source of indirect heating.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
Pursuant to 326 IAC 6-3-1.5(2), natural gas-fired combined combustion turbine (CTG-01) is not subject to the requirements of 326 IAC 6-3, since this unit is not considered manufacturing processes and, pursuant to 326 IAC 1-2-59, liquid and gaseous fuels and combustion air are not considered as part of the process weight.

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations
The natural gas-fired Combined Cycle Combustion Turbine is not subject to 326 IAC 7-1.1 because although this unit has a potential to emit sulfur dioxide (SO_2) greater than 25 tons per year or 10 pounds per hour, the unit does not combust coal or fuel oil.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
The combustion turbine is subject to the requirements of 326 IAC 8-1-6, because it was constructed after January 1, 1980, and its unlimited VOC potential emissions are equal to or greater than twenty-five (25) tons per year, and the unit is not regulated by other rules in 326 IAC 8. Therefore, a Best Available Control Technology (BACT) analysis was required for the combustion turbine (see Appendix B of this TSD).

According to the BACT analysis contained in Appendix B of this TSD, IDEM, OAQ has determined that the following requirements represent BACT for the combustion turbine:

Pursuant to 326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities), the Best Available Control Technologies (BACT) for the combustion turbine generator shall be as follows:

(a) The VOC emissions from the combustion turbine generator shall be controlled by catalytic oxidation and good combustion practices.

(b) VOC emissions from the CTG-01 shall not exceed 0.0013 pounds per MMBtu.

(c) VOC emissions from the CTG-01 shall not exceed 1.0 ppmvd @ 15% O_2 based on a 3-hr average.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
The requirements of 326 IAC 9-1 do not apply to the combined combustion turbine, 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 10-1 (Nitrogen Oxide Emission Requirements)
This source is not located in Clark or Floyd County. Therefore, the requirements of 326 IAC 10-1 are not applicable.

326 IAC 10-2 (NO_X Emissions from Large Affected Units)
Pursuant to 326 IAC 1021(a)(1), the emission unit description identified as XXXX is not subject to the requirements of 326 IAC 10.2 because it is 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 combined combustion turbine, since this unit is not a blast furnace gas-fired boiler, a Portland cement kiln, or a facility specifically listed under 326 IAC 10-3-1(a)(2).

326 IAC 21 (Acid Deposition Control)
326 IAC 21 incorporates by reference the provisions of 40 CFR 72 through 40 CFR 78 for the purpose of implementing an acid rain program that meets the requirements of Title IV of the Clean Air Act and to incorporate monitoring, record keeping, and reporting requirements.

Title IV of the Clean Air Act Amendments required USEPA to establish a program to reduce emissions of acid rain-forming pollutants, called the Acid Rain Program. The overall goal of this program is to achieve significant environmental benefits through reduction in SO_2 and NO_x emissions from fossil fuel-fired electric generating facilities. To achieve this goal, the program implemented a market-based approach for controlling air pollution. Under the market-based aspect of the program, existing affected units were allocated SO_2 allowances by the USEPA, which may be used to offset emissions or traded under the market allowance program. New sources subject to the Acid Rain Program are required to secure sufficient SO_2 allowances from the market. In addition, to ensure that facilities do not exceed their allowances, affected units are required to monitor and report their emissions using a continuous emissions monitoring system, as approved under 40 CFR Part 75.

The Facility is subject to the Acid Rain Program based on the provisions of 40 CFR 72.6(a)(3) because the CTGs are considered “utility units” under the program definition and they do not meet the exemptions listed under paragraph (b) of this section. MCE will be required to submit an Acid Rain Permit application at least 24 months prior to the date on which the affected unit commences operation. MCE will submit an Acid Rain Permit application for the Facility in compliance with these requirements prior to this deadline. After the CTG commences operation, MCE will secure sufficient Acid Rain SO_2 allowances to offset actual emissions.

326 IAC 24 (Cross-State Air Pollution Rule (CSAPR) Programs)
See the Cross-State Air Pollutant Rule (CSAPR) section above.

Natural Gas-Fired Boiler (AUX)

326 IAC 5-1-3 (Temporary Alternative Opacity Limitations)
Pursuant to 326 IAC 5-1-3 (a) (Temporary Alternative Opacity Limitations), when building a new fire in a boiler, or shutting down a boiler, opacity may exceed the applicable opacity limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period. Opacity in excess of the applicable opacity limit established in 326 IAC 5-1-2 shall not continue for more than two (2) six (6)-minute averaging periods in any twenty-four (24) hour period.

If a facility cannot meet the opacity limitations of 326 IAC 5-1-3(a) or (b), the Permittee may submit a written request to IDEM, OAQ, for a temporary alternative opacity limitation in accordance with 326 IAC 5-1-3(d). The Permittee must demonstrate that the alternative limit is needed and justifiable.

326 IAC 6-2-1 (Particulate 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) 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.

Indirect Heating Units Which Began Operation After September 21, 1983						
Facility	Construction Date	Operating Capacity (MMBtu/hr)	Q (MMBtu/hr)	Calculated Pt (lb/MMBtu)	Particulate Limitation, (Pt) (lb/MMBtu)	PM PTE based on AP-42 (lb/MMBtu)
(Plant 1) Auxiliary Boiler (AUX)	2026	96	192	0.28	0.28	0.002
(Plant 2) Auxiliary Boiler (AUX-02)	2026	96	192	0.28	0.28	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 natural gas-fired auxiliary boiler (AUX) is not subject to the requirements of 326 IAC 6-3, since this boiler is an indirect heating unit. Additionally, pursuant to 326 IAC 6-3-1.5(2), natural gas-fired boiler (AUX) is not subject to the requirements of 326 IAC 6-3, since this unit is not considered a manufacturing process and, pursuant to 326 IAC 1-2-59, liquid and gaseous fuels and combustion air are not considered as part of the process weight.

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations
This emission unit is not subject to 326 IAC 326 IAC 7-1.1 because it has a potential to emit (or limited potential to emit) sulfur dioxide (SO2) of less than 25 tons per year or 10 pounds per hour.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
Even though, this natural gas-fired auxiliary boiler (AUX) 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 9-1 (Carbon Monoxide Emission Limits)
The requirements of 326 IAC 9-1 do not apply to the natural gas-fired auxiliary boiler (AUX), 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 natural gas-fired auxiliary boiler (AUX), since this unit is not a blast furnace gas-fired boiler, a Portland cement kiln, or a facility specifically listed under 326 IAC 10-3-1(a)(2).

Emergency Generator and Emergency Fire Pump Engine (EG and FP)

326 IAC 6-2-1 (Particulate Emission Limitations for Sources of Indirect Heating)
The emergency diesel-fired generator (EG) and the emergency diesel-fired fire pump (FP) are each not subject to 326 IAC 6-2 since each of these units is not a source of indirect heating, as defined by 326 IAC 1-2-19.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
Pursuant to 326 IAC 6-3-1.5(2), the emergency diesel-fired generator (EG) and the emergency diesel-fired fire pump (FP) are each not subject to the requirements of 326 IAC 6-3, since each of these units are not considered manufacturing processes and, pursuant to 326 IAC 1-2-59, liquid and gaseous fuels and combustion air are not considered as part of the process weight..

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations
These emission units are not subject to 326 IAC 326 IAC 7-1.1 because each has a potential to emit (or limited potential to emit) sulfur dioxide (SO2) of less than 25 tons per year or 10 pounds per hour.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
Even though, the emergency diesel-fired generator (EG) and the emergency diesel-fired fire pump (FP) were constructed after January 1, 1980, each are not subject to the requirements of 326 IAC 8-1-6 because the unlimited VOC potential emissions are less than twenty-five (25) tons per year, each.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
The requirements of 326 IAC 9-1 do not apply to the emergency diesel-fired generator (EG) and the emergency diesel-fired fire pump (FP), 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 emergency diesel-fired generator (EG) and the emergency diesel-fired fire pump (FP), since each unit is not a blast furnace gas-fired boiler, a Portland cement kiln, or a facility specifically listed under 326 IAC 10-3-1(a)(2).

Storage Tanks

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
Even though the six (6) tanks will be constructed after January 1, 1980, each is not subject to the requirements of 326 IAC 8-1-6 because the unlimited VOC potential emissions are less than twenty-five (25) tons per year, each.

326 IAC 8-9 (Volatile Organic Liquid Storage Vessels)
Pursuant to 326 IAC 8-9-1(a), the six (6) tanks are not subject to this rule because these units are not located in Clark, Floyd, Lake, or Porter County.

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to assure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions; however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

(a) The Compliance Determination Requirements applicable to this source are as follows:

(1) In order to assure compliance with 326 IAC 2-2-3 (PSD BACT), the dry low NO_X burners for NO_X control shall be in operation and control emissions from the combined cycle combustion turbine at all times the combined cycle combustion turbine is in operation.

(2) In order to assure compliance with Conditions 326 IAC 2-2-3 (PSD BACT), the catalytic oxidation system for VOC and CO control shall be in operation and control emissions from the combined cycle combustion turbine at all times the combined cycle combustion turbine is in operation.

(3) To determine the compliance status with 326 IAC 2-2-3 (PSD BACT), the following equation shall be used to determine the CO_{2e} emissions from the combined cycle combustion turbine:

CO_2e emissions (tons/month) = [(Fuel Usage (mmscf/month)
x Heat Content (mmbtu/mmscf))
x (CO_2 EF (lb/mmbtu) x CO_2 GWP + CH_4 EF (lb/mmbtu)
x CH_4 GWP + N_2O EF (lb/mmbtu) x N_2O GWP)]
x 1/2000 (ton/lb)

Where:

Fuel Usage (mmscf/month) = monthly fuel usage data from company records
Heat Content (mmbtu/mmscf) = standard value in AP-42 for natural gas or vendor data, if available
CO_2 EF (lb/mmbtu) = emission factor from GHG Mandatory Reporting Rule (MRR) (40 CFR 98, Subpart C) for natural gas
CH_4 EF (lb/mmbtu) = emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
N_2O EF (lb/mmbtu) = emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas

CO_2 GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)

(4) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NO_X and CO emissions.

(5) All CEMS required by this permit shall meet all applicable performance specifications of 40 CFR 60 and 40 CFR 75 or any other applicable performance specifications, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

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

(7) Whenever a NO_X or CO CEM is down for more than twenty-four (24) hours, the Permittee shall follow good air pollution control practices.

(8) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a CEMS pursuant to 40 CFR 60, 40 CFR 75, and 40 CFR 96.

(9) In order to assure compliance with 326 IAC 2-2-3 (PSD BACT), the low NO_X burners for NO_X control shall be in operation and control emissions from the boiler at all times the boiler is in operation.

(10) In order to assure compliance with 326 IAC 2-2-3 (PSD BACT), the Permittee shall only use natural gas in the auxiliary boiler.

(11) To determine the compliance status with 326 IAC 2-2-3 (PSD BACT), the following equation shall be used to determine the CO_{2e} emissions from the Auxiliary Boiler:

CO_{2e} emissions (tons/month) = [(Fuel Usage (mmscf/month)
x Heat Content (mmbtu/mmscf))
x (CO_2 EF (lb/mmbtu) x CO_2 GWP + CH_4 EF (lb/mmbtu)
x CH_4 GWP + N_2O EF (lb/mmbtu) x N_2O GWP)]
x 1/2000 (ton/lb)

Where:

Fuel Usage (mmscf/month) = monthly auxiliary boiler fuel usage data from company records
Heat Content (mmbtu/mmscf) = standard value in AP-42 for natural gas, or vendor data, if available
CO_2 EF (lb/mmbtu) = emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
CH_4 EF (lb/mmbtu) = emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
N_2O EF (lb/mmbtu) = emission factor from GHG MRR (40 CFR 98, Subpart C) for natural gas
CO_2 GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)

(12) To determine compliance with 326 IAC 2-2-3 (PSD BACT), the following equation shall be used to determine the CO_{2e} emissions from the emergency diesel engine:

CO_{2e} emissions (tons/month) = [(Fuel Usage (gal/month)
x Heat Content (mmbtu/gal))
x (CO_2 EF (lb/mmbtu) x CO_2 GWP + CH_4 EF (lb/mmbtu)
x CH_4 GWP + N_2O EF (lb/mmbtu) x N_2O GWP)]
x 1/2000 (ton/lb)

Where:

Fuel Usage (gal/month) = monthly fire pump engine/emergency generator fuel usage data from company records
Heat Content (mmbtu/gal) = standard value in AP-42 for diesel fuel, or vendor data, if available
CO_2 EF (lb/mmbtu) = emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
CH_4 EF (lb/mmbtu) = emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
N_2O EF (lb/mmbtu) = emission factor from GHG MRR (40 CFR 98, Subpart C) for diesel fuel
CO_2 GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)
CH_4 GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)
N_2O GWP = global warming potential from GHG MRR (40 CFR 98, Subpart A)

Startup/Shutdown

(a) A startup is defined as the operation in the period beginning when continuous fuel flow to the combustion turbine is initiated and ending when the CTG-01 achieves steady-state operating condition:

(1) A cold start is defined as when the combustion turbine has been shut down for more than 72 hours.

(2) A warm start is defined as when the combustion turbine has been shut down for a period from 8 to 72 hours.

(3) A hot start is defined as when the combustion turbine has been shut down for less than 8 hours.

(b) Steady-state is defined as the period of time and load conditions when the combustion turbine is operating in emissions compliance.

(c) Shutdown is defined as the period of time the CTG-01 exits steady state operating condition and ending with termination of combustion in each turbine.

(d) The following records shall be kept by the source:
(1) Number of minutes in each hour that the unit is in startup mode.
(2) Number of minutes in each hour that the unit is in shutdown mode.
(3) Records shall be maintained at any time the unit is off-line.

(e) An event is defined as:

(1) exactly one (1) startup or exactly one (1) shutdown.

Testing Requirements:

Summary of Testing Requirements					
Emission Unit	**Control Device**	**Timeframe for Initial Testing or Date of Initial Valid Demonstration**	**Pollutant/ Parameter**	**Frequency of Testing**	**Authority**
Combined Cycle Combustion Turbine (CTG-01)	--	60/180*	PM, PM_{10}, & $PM_{2.5}$	Every 5 years	326 IAC 2-2-3
	Oxidation Catalyst		VOC	Every 5 years	326 IAC 2-2-3, 326 IAC 8-1-6
	--		H_2SO_4	Every 5 years	326 IAC 2-2-3
Auxiliary Boiler (AUX)	--	60/180*	PM, PM_{10}, & $PM_{2.5}$	Every 5 years	326 IAC 2-2-3
	--		NOx	Every 5 years	326 IAC 2-2-3
	--		CO	Every 5 years	326 IAC 2-2-3
	--		H_2SO_4	Every 5 years	326 IAC 2-2-3
* Within 60 days after achieving the maximum production rate of the emission unit, but not later than 180 days after initial startup of the emission unit.					

Continuous Emissions Monitoring System (CEMS) and Continuous Opacity Monitoring (COM) Requirements:

Emission Unit	Type of Continuous Monitor (Pollutant Monitored)	Applicable Rule or Authority
Combined Cycle Combustion Turbine CTGA	CEMS (NOx)	326 IAC 3-5 326 IAC 2-7-6(1) & (6) 326 IAC 2-2 (BACT) 40 CFR 60, Subpart KKKK

(b) The Compliance Monitoring Requirements applicable to this source are as follows:

Control Device	Type of Parametric Monitoring	Frequency	Range or Specification
Oxidation Catalyst	3-hour average catalyst 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*
*Note: Compliance monitoring parameter value(s) or specification(s) from the most recent compliant stack test will be specified in the stack test report available via IDEM's Virtual File Cabinet (VFC) 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.			

These monitoring conditions are necessary because the oxidation catalyst for the combined cycle combustion turbine must operate properly to assure compliance with 326 IAC 2-2-3 (PSD BACT).

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) Sections A, D.1, E.2, E.3, E.4, and F - Emission unit descriptions and permit requirements for the Siemens model turbine have been removed.

(2) Condition D.1.2(e) has been revised to include the updated PM_{10}/$PM_{2.5}$ emissions rate from turbine vendor data.

(3) Condition D.1.3 has been added to include Air Quality Impact Requirements.

(4) Conditions D.1.5 and D.1.6 - Condition citations have been corrected.

(4) Condition D.1.9 has been revised to include testing requirements to show compliance with air quality impact requirements.

(5) Condition D.1.12(h) – Condition reference citations have been updated.

(6) Reporting forms for the Siemens model turbine have been removed.

(7) Reporting forms - The source address has been updated to include the source zip code.

(8) Section E.4 - NSPS subpart TTTT has been replaced by subpart TTTTa due to a change in applicability based on unit construction date.

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

*****

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

*****

A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)][326 IAC 2-7-1(~~22~~**20**)]

*****

A.2 Source Definition

This stationary combined-cycle electric generating facility consists of two (2) plants:

(a) Plant 1, Maple Creek Energy LLC (Source ID: 153-00056), is located at W CR 1040 N 0.5 miles South and SR 63 0.4 miles West, Fairbanks, Indiana 47849; and

(b) Plant 2, Maple Creek Energy II LLC (Source ID: 153-00064), is/will be located at W CR 1040 N 0.5 miles South and SR 63 0.4 miles West, Fairbanks, Indiana 47849.

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

~~Note: Only one combined cycle system will be constructed. Maple Creek has 2 options and has not determined which one will be installed. Both options are listed here.~~

~~Option 1: Siemens Model SCC6-9000HL Turbine~~

~~(a1) One (1) natural gas-fired combined cycle system, identified as CTGA, approved in 2023 for construction, with a maximum heat input capacity of 3,800 MMBtu per hour, equipped with a Siemens combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG), using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and~~

~~CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.~~

~~Under 40 CFR Part 60, Subpart KKKK, this unit considered an affected facility.~~
~~Under 40 CFR Part 60, Subpart TTTT, this unit is considered an affected facility.~~

~~or~~

~~Option 2: GE Model 7HA.03Turbine~~

(a~~2~~) One (1) natural gas-fired combined cycle system, identified as ~~CTGB~~**CTG-01**, approved in ~~2023~~ **2026** for construction, with a maximum heat input capacity of ~~4,200~~**4,253** MMBtu per hour, equipped with a GE combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG) **and one air-cooled condenser (ACC)**, using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.

Under 40 CFR 60, Subpart KKKK, CTG-01 was constructed after February 18, 2005, has a maximum heat input capacity of greater than 10 MMBtu/hr, and is a stationary combustion turbine (CTG).

Under 40 CFR 60, Subpart TTTTa, CTG-01 was constructed after May 23, 2023, has a base load rating greater than 250 MMBtu/hr of fossil fuel, and serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system, and is an affected unit.

(b) One (1) natural gas-fired auxiliary boiler, identified as AUX, equipped with ultra-low-NOx burners, approved in ~~2023~~ **2026** for construction, with a maximum heat input capacity of 96 MMBtu per hour, ~~using no add-on control,~~ and exhausting to stack AUX.

Under 40 CFR 60, Subpart Dc, AUX was constructed after June 9, 1989, has a maximum design heat input capacity of less than 100 MMBtu/hr, but greater than 10 MMBtu/hr, and is considered a small steam generating unit.~~Under 40 CFR Part 60, Subpart Dc, this unit is considered an affected facility.~~

(c) One (1) **diesel-fired** emergency generator ~~fueled with~~**using** ultra-low-sulfur-distillate (ULSD), identified as EG, approved in ~~2023~~ **2026** for construction, with a maximum **output rating of 2,012** horsepower (hp)~~ of 2,012, displacement < 30 L/cylinder,~~ and exhausting to stack EG.

Under 40 CFR 60, Subpart IIII, EG is considered a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and is not a fire pump engine.
~~Under 40 CFR Part 60, Subpart IIII, this unit is considered an affected facility.~~
Under 40 CFR 63, Subpart ZZZZ, EG was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.~~Under 40 CFR Part 63, Subpart ZZZZ, this unit is considered a new affected source.~~

(d) **One (1) diesel-fired emergency fire pump engine using ultra-low-sulfur-distillate (ULSD), identified as FP, approved in 2026 for construction, with a maximum output rating of 420 horsepower (hp), and exhausting to stack FP.**~~One (1) 420-~~

~~brake hp emergency fire pump fueled with ULSD, identified as FP, approved in 2023 for construction, and exhausting to stack EF.~~

Under 40 CFR 60, Subpart IIII, FP is considered a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, and was manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Under 40 CFR 63, Subpart ZZZZ, FP was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.~~Under 40 CFR Part 60, Subpart IIII, this unit is considered an affected facility.~~
~~Under 40 CFR Part 63, Subpart ZZZZ, this unit is considered a new affected source.~~

*****

A.~~3~~**4** 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, as defined in 326 IAC 2-7-1(~~21~~**19**):

(a) Six (6) tanks~~, each using no control,~~ including:

Emission Unit	Quantity	Year Approved for Construction	Maximum Storage Capacity, Each (gal)
Ammonia storage tank (19% aqueous ammonia)	1	~~2023~~**2026**	30,000
Emergency Diesel Generator ULSD (integrated “belly tank”)	1	~~2023~~**2026**	2,000
Emergency Fire Pump ULSD (integrated “belly tank”)	1	~~2023~~**2026**	200
Lube Oil Tank	1	~~2023~~**2026**	10,000
Demineralized Water Tank	1	~~2023~~**2026**	500,000
Potable/Raw Water Tank	1	~~2023~~**2026**	500,000

*****

A.~~4~~**5** 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.10 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.2 Revocation of Permits [326 IAC 2-1.1-9(5)]

Pursuant to 326 IAC 2-1.1-9(5)(Revocation of Permits), the Commissioner may revoke this permit if construction is not commenced ~~on or before June 19, 2026,~~**within eighteen (18) months after receipt of this approval** or if construction is suspended for a continuous period of one (1) year or more.

****

B.11 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.12 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**).

*****

(b) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions. The PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(~~35~~**33**).

*****

B.13 **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.17 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)][326 IAC 2-7-8(a)][326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(~~35~~**33**).

*****

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

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(~~21~~**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.19 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.21 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.24 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.7 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.8 Performance Testing [326 IAC 3-6]

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

*****

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

The ERP does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(~~35~~**33**).

*****

C.15 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.16 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.~~16~~**17** 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.~~17~~**18** General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [326 IAC 2-2][326 IAC 2-3]

*****

C.~~18~~**19** General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2][326 IAC 2-3]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under ~~Section B - Emergency Provisions~~ **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.~~19~~**20** Compliance with 40 CFR 82 and 326 IAC 22-1

*****

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

~~Option 1: Siemens Model SCC6-9000HL Turbine~~

~~(a1) One (1) natural gas-fired combined cycle system, identified as CTGA, approved in 2023 for construction, with a maximum heat input capacity of 3,800 MMBtu per hour, equipped with a Siemens combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG), using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.~~

~~Under 40 CFR Part 60, Subpart KKKK, this unit considered an affected facility.~~
~~Under 40 CFR Part 60, Subpart TTTT, this unit is considered an affected facility.~~

~~or~~

~~Option 2: GE Model 7HA.03Turbine~~

(a~~2~~) One (1) natural gas-fired combined cycle system, identified as ~~CTGB~~**CTG-01**, approved in ~~2023~~ **2026** for construction, with a maximum heat input capacity of ~~4,200~~**4,253** MMBtu per hour, equipped with a GE combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG) **and one air-cooled condenser (ACC)**, using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.

Under 40 CFR 60, Subpart KKKK, CTG-01 was constructed after February 18, 2005, has a maximum heat input capacity of greater than 10 MMBtu/hr, and is a stationary combustion turbine (CTG).

Under 40 CFR 60, Subpart TTTTa, CTG-01 was constructed after May 23, 2023, has a base load rating greater than 250 MMBtu/hr of fossil fuel, and serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system, and is an affected unit.

*****

D.1.1 PSD and VOC BACT [326 IAC 2-2-3] [326 IAC 8-1-6]

~~Option 1: Siemens Model SCC6-9000HL Turbine~~

~~(a) The CTG shall combust pipeline-quality natural gas.~~

~~(b) PM, PM10 and PM2.5 emissions from the combined-cycle combustion turbine generator shall be controlled through the use of good combustion practices.~~

~~(c) PM emissions from the Siemens CTG shall not exceed 0.0049 lb/MMBtu.~~

~~(d) PM10 emissions from the Siemens CTG shall not exceed 0.0049 lb/MMBtu.~~

~~(e) PM2.5 emissions from the Siemens CTG shall not exceed 0.0049 lb/MMBtu.~~

~~(f) The NOx emissions from the combustion turbine generator shall be controlled by a Selective Catalytic Reduction system and dry-low-NOx combustors.~~

~~(g) The NOx emissions shall not exceed 2.0 ppmvd @ 15% O2 based on a 3-hr average.~~

~~(h) NOx emissions from the Siemens CTG shall not exceed 0.0085 lb/MMBtu.~~

~~(i) Ammonia slip emissions shall not exceed 5.0 ppmvdc.~~

~~(j) The VOC emissions from the combustion turbine generator shall be controlled by catalytic oxidation and good combustion practices.~~

~~(k) VOC emissions from the Siemens CTG shall not exceed 0.0015 pounds per MMBtu.~~

~~(l) VOC emissions from the Siemens CTG shall not exceed 1.0 ppmvd @ 15% O2 based on a 3-hr average.~~

~~(m) The CO emissions from the Siemens combustion turbine generator shall be controlled using good combustion practices and an oxidation catalyst.~~

~~(n) CO emissions from the Siemens CTG shall not exceed 2.0 ppmvd @ 15% O2 based on a 3-hr average.~~

~~(o) CO emissions from the Siemens CTG shall not exceed 0.0051 pounds per MMBtu.~~

~~(p) SO2 and H_2SO_4 shall be controlled through the use of pipeline-quality natural gas.~~

~~(q) SO2 emissions from the Siemens CTG shall not exceed 0.0017 lb/MMBtu, based on a 3 - hour average.~~

~~(r) H_2SO_4 emissions from the Siemens CTG shall not exceed 0.0004 lb/MMBtu.~~

~~(s) CO2e emissions from the Siemens CTG shall not exceed 726 lb/MW-hr (gross) corrected to ISO conditions.~~

~~(t) CO2e emissions from the Siemens CTG shall not exceed 2,040,335 tons per twelve (12) consecutive month period with compliance determined at the end of each month.~~

~~(u) CO2e emissions from the Siemens CTG shall be limited through the use of good combustion practices.~~

~~OR~~

~~Option 2: GE Model 7HA.03Turbine~~

(a) ~~The~~ CTG**-01** shall combust pipeline-quality natural gas.

(b) PM, PM_{10} and $PM_{2.5}$ emissions from the ~~combined-cycle combustion turbine generator~~**CTG-01** shall be ~~controlled~~**limited** through the use of good combustion practices.

(c) PM emissions from the ~~Siemens~~ CTG**-01** shall not exceed 0.~~0049~~**0058** lb/MMBtu**, excluding periods of startup and shutdown**.

(d) PM_{10} emissions from the ~~Siemens~~ CTG**-01** shall not exceed 0.~~0049~~**0058** lb/MMBtu**, excluding periods of startup and shutdown**.

(e) **The** $PM_{2.5}$ emissions from the ~~Siemens~~ CTG**-01** shall not exceed 0.~~0049~~**0058** lb/MMBtu**, excluding periods of startup and shutdown**.

(f) The NOx emissions from ~~the combustion turbine generator~~**CTG-01** shall be controlled by a Selective Catalytic Reduction system and dry-low-NOx combustors.

(g) The NOx emissions **from CTG-01** shall not exceed 2.0 ppmvd @ 15% O_2 based on a 3-hr average**, excluding periods of startup and shutdown**.

(h) NOx emissions from ~~the Siemens~~ CTG**-01** shall not exceed ~~0.0085~~**30.9** lb/~~MMBtu~~**hr, excluding periods of startup and shutdown**.

(i) ~~Ammonia slip emissions shall not exceed 5.0 ppmvdc.~~

The VOC emissions from the ~~combustion turbine generator~~**CTG-01** shall be controlled by catalytic oxidation and good combustion practices.

(j) **VOC emissions from the CTG-01 shall not exceed 0.0013 pounds per MMBtu, excluding periods of startup and shutdown.**

(k) VOC emissions from the ~~Siemens CTG shall not exceed 0.0015 pounds per MMBtu.~~

~~(l) VOC emissions from the Siemens CTG~~**CTG-01** shall not exceed 1.0 ppmvd @ 15% O2 based on a 3-hr average**, excluding periods of startup and shutdown**.

(~~m~~**l**) The CO emissions from ~~the Siemens combustion turbine generator~~**CTG-01** shall be controlled using good combustion practices and an oxidation catalyst.

(~~n~~**m**) CO emissions from ~~the Siemens~~ CTG**-01** shall not exceed 2.0 ppmvd @ 15% O2 based on a 3-hr average**, excluding periods of startup and shutdown**.

(n) CO emissions from the CTG-01 shall not exceed 0.0044 pounds per MMBtu, excluding periods of startup and shutdown.

(o) ~~CO emissions from the Siemens CTG shall not exceed 0.0051 pounds per MMBtu.~~

~~(p)~~ SO_2 and H2SO4 **from CTG-01** shall be controlled through the use of pipeline-quality natural gas.

(~~q~~**p**) SO_2 emissions from the ~~Siemens~~ CTG**-01** shall not exceed 0.~~0017~~**0019** lb/MMBtu~~, based on a 3 - hour average~~.

(~~r~~**q**) H_2SO_4 emissions from the **CTG-01** shall not exceed 0.0013 lb/MMBtu.

(~~Siemens CTG~~**r)** **CO_2e emissions from the CTG-01** shall not exceed ~~0.0004 lb/MMBtu.~~

~~(s) CO2e emissions from the Siemens CTG shall not exceed 726~~**800** lb/MW-hr (gross) corrected to ISO conditions.

(~~t~~**s**) CO_2e emissions from ~~the Siemens~~ CTG**-01** shall not exceed ~~2,040,335~~**2,065,094** tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(~~u~~**t**) CO_2e emissions from ~~the Siemens~~ CTG**-01** shall be limited through the use of ~~good combustion practices.~~ **low-carbon fuel (natural gas) with high-efficiency, combined cycle generation.**

*****

D.1.2 Startup and Shutdown Limitations for Combustion Turbine [326 IAC 2-2-3]

~~Option 1: Siemens Model SCC6-9000HL Turbine~~

~~(a) A startup is defined as the operation in the period beginning when continuous fuel flow to the combustion turbine is initiated and ending when the CCCT achieves steady-state operating condition.~~

~~(1) A cold start is defined as when the combustion turbine has been shut down for more than 48 hours.~~

~~(2) A warm start is defined as when the combustion turbine has been shut down for a period from 8 to 48 hours.~~

~~(3) A hot start is defined as when the combustion turbine has been shut down for less than 8 hours.~~

~~(b) Steady-state is defined as the period of time and load conditions when in dry low NOx mode and the combustion turbine is operating in emissions compliance.~~

~~(c) Shutdown is defined as the period of time the CCCT exits steady state operating condition and ending with termination of combustion in each turbine.~~

~~(d) The following records shall be kept by the source:~~

~~(1) Number of minutes in each hour that the unit is in startup mode.~~

~~(2) Number of minutes in each hour that the unit is in shutdown mode.~~

~~(3) Records shall be maintained at any time the unit is off-line.~~

~~(e) An event is defined as:~~

~~(1) exactly one (1) startup or exactly one (1) shutdown~~

~~For CO (1-hour and 8-hour) and PM_{10}/$PM_{2.5}$ (24-hour), the source determined the worst-case operating scenario that results in the highest modeled impacts to be a cold start of the CCCT. The modeled cold start emission rates are based on startup emission totals provided by the turbine vendor as provided below:~~

~~CO – 1,724 lb/event~~
~~PM_{10}/$PM_{2.5}$ – 5.3 lb/event~~

~~(f) The NO_X emissions from the combined cycle combustion turbine stack shall not exceed 20.7 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.~~

~~(g) The CO emissions from the combined cycle combustion turbine stack shall not exceed 206.6 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.~~

~~(h) The VOC emissions from the combined cycle combustion turbine stack shall not exceed 29.3 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.~~

~~Option 2: GE Model 7HA.03Turbine~~

*****

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

D.1.4 NO_X Control

In order to assure compliance with Conditions D.1.1(~~d), (e)~~**f), (g),** and (~~f~~**h**), the dry low NO_X burners for NO_X control shall be in operation and control emissions from the ~~CCCT~~**natural gas-fired combined cycle combustion turbine (CTG-01)** at all times the ~~CCCT~~**natural gas-fired combined cycle combustion turbine (CTG-01)** is in operation.

D.1.5 ~~VOC and CO Control~~**Ammonia Slip Emissions**

In order to assure compliance with Conditions D.1.1(~~h~~**f), (g), and (h), Ammonia Slip emissions from the natural gas-fired combined cycle combustion turbine (CTG-01) shall not exceed 5.0 ppmvdc at all times the natural gas-fired combined cycle combustion turbine (CTG-01) is in operation.**

D.1.6 VOC and CO Control

In order to assure compliance with Conditions D.1.1(j) through (~~m~~**n**), the catalytic oxidation system for VOC and CO control shall be in operation and control emissions from the ~~CCCT at all times the CCCT~~**natural gas-fired combined cycle combustion turbine (CTG-01) at all times the natural gas-fired combined cycle combustion turbine (CTG-01)** is in operation.

D.1.~~6~~**7** Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Conditions D.1.1(~~t~~**r) and (s**), the following equation shall be used to determine the CO_2e emissions from the CCCT:
*****

D.1.**8 Startup and Shutdown**

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbine shall be as follows:

(a) A startup is defined as the operation in the period beginning when continuous fuel flow to the combustion turbine is initiated and ending when the CCCT achieves steady-state operating condition:

(1) A cold start is defined as when the combustion turbine has been shut down for more than 72 hours.

(2) A warm start is defined as when the combustion turbine has been shut down for a period from 8 to 72 hours.

(3) A hot start is defined as when the combustion turbine has been shut down for less than 8 hours.

(b) Steady-state is defined as the period of time and load conditions when the combustion turbine is operating in emissions compliance.

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

~~7~~**(d) An event is defined as exactly one (1) startup or exactly one (1) shutdown.**

D.1.~~7~~**9** Continuous Emissions Monitoring [326 IAC 3-5] [326 IAC 2-7-6(1), (6)] [326 IAC 2-2-3] [40 CFR 60, Subpart TTTT**a** (4T**a**)] [40 CFR 60, Subpart KKKK (4K)]

(a) Pursuant to 326 IAC 3-5 (Continuous Monitoring of Emissions) continuous emission monitoring systems for the ~~CCCT~~**natural gas-fired combined cycle combustion turbine (CTG-01)** shall be calibrated, maintained, and operated for measuring NO_X and CO emissions, 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 TTTT**a** (4T**a**), and 40 CFR 60, Subpart KKKK (4K).

D.1.~~8~~**10** Testing Requirements [326 IAC 2-1.1-11]

~~Option 1: Siemens Model SCC6-9000HL Turbine~~

~~(a) In order to demonstrate compliance with Conditions D.1.1(a), (b) and (c), not later than 180 days after initial start-up, the Permittee shall perform PM, PM10, and PM2.5 testing on CTGA, utilizing methods as approved by the Commissioner at least once every five~~

~~(5) years from the date of the most recent valid compliance demonstration. PM_{10} and $PM_{2.5}$ includes filterable and condensable PM.~~

~~(b) In order to demonstrate compliance with Conditions D.1.1(k) and (l), not later than 180 days after initial start-up, the Permittee shall perform VOC testing on CTGA, utilizing methods as approved by the Commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.~~

~~(c) In order to demonstrate compliance with Conditions D.1.1(r), not later than 180 days after initial start-up, the Permittee shall perform H_2SO_4 testing on CTGA, utilizing methods as approved by the Commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.~~

~~(d) 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.~~

~~Option 2: GE Model 7HA.03Turbine~~

(a) In order to demonstrate compliance with Conditions D.1.1(~~a), (b~~**c), (d**) and (~~c),~~**e) within 60 days after achieving the maximum production rate of the emission unit, but** not later than 180 days after initial start-up~~,~~ **of the natural gas-fired combined cycle combustion turbine (CTG-01),** the Permittee shall perform PM, PM_{10}, and $PM_{2.5}$ testing ~~on CTGA,~~**of the natural gas-fired combined cycle combustion turbine (CTG-01),** utilizing methods as approved by the Commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration. PM_{10} and $PM_{2.5}$ includes filterable and condensable PM.

(b) In order to demonstrate compliance with Conditions D.1.1(~~k~~**j**) and (~~l),~~**k), within 60 days after achieving the maximum production rate of the emission unit, but** not later than 180 days after initial start-up~~,~~ **of the natural gas-fired combined cycle combustion turbine (CTG-01),** the Permittee shall perform VOC testing ~~on CTGA,~~**of the natural gas-fired combined cycle combustion turbine (CTG-01),** utilizing methods as approved by the Commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

(c) In order to demonstrate compliance with Conditions D.1.1(~~r~~**q**), not later than 180 days after initial start-up, the Permittee shall perform H_2SO_4 testing on ~~CTGA~~**CTG-01**, utilizing methods as approved by the Commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.

*****

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

D.1.~~9~~**11** Oxidation Catalyst Parametric Monitoring

~~(a) In order to assure compliance with Conditions D.1.1(j), (k), (l), (m), (n) and (o), a~~**(a) A** continuous monitoring system shall be calibrated, maintained, and operated on each oxidation catalyst for measuring operating temperature~~.~~ **while operating CTG-01.** For the ~~purposes~~**purpose** of this condition, continuous ~~monitoring~~ means ~~recording the temperature~~ no less often than every 15 minutes. The output of this system shall be recorded as a ~~three (3)~~ -hour average. From the date of startup **of CTG-01** until the stack test results are available, the Permittee shall operate the oxidation catalyst at or above the 3-hour average temperature of 500°F.

(b) The Permittee shall determine the 3-hour average temperature from the latest valid stack test that demonstrates compliance with limits in Conditions D.1.1(**j), (**k), (~~l), (n~~**m**), and (~~o~~**n**).

****

D.1.~~10~~**12** NO_X and CO Continuous Emissions Monitoring (CEMS) Equipment Downtime

****

(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 normal operations, with at least four (4) hours between each set of readings, until a NOx and CO CEMS is online.

D.1.~~11~~**13** Record Keeping Requirement

(a) In order to document the compliance status with ~~Condition~~**Conditions** D.1.1(~~t~~**r) and (s**), the Permittee shall maintain monthly records of the **following:**

(1) The amount of fuel combusted in the combined cycle combustion turbine.

~~(b) To document the compliance status with Conditions D.1.1(s) and (t), the Permittee shall maintain monthly records of the CO_2e emissions.~~

~~(c~~ **(2) The CO_2e emissions from CTG-01.**

(**b**) To document compliance with Condition D.1.2, the Permittee shall maintain records of the following:

(1) The type of operation (i.e. startup, shutdown) with supporting operational data;

(2) The total number of minutes for startup and shutdown operation per event; and

(3) The CEMS data, fuel flow meter data, and/or Method 19 calculations used to determine the mass emissions rate corresponding to each startup and shutdown operating period.

~~(d~~**(4) The monthly records of the combined startup and shutdown PM, PM10, and PM2.5 emissions from CTG-01.**

(5) The monthly records of the combined startup and shutdown VOC emissions from CTG-01.

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

(~~f~~**d**) In the event that a breakdown of the NO_X and CO CEMS occurs, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(~~g~~**e**) The Permittee shall maintain the monthly records of the NO_X and CO emissions from the CCCT based on the CEM data.

(~~h~~**f**) In order to document the compliance status with Condition D.1.~~9~~**11**, the Permittee shall maintain continuous temperature records (on a 3-hour average basis) for each oxidation catalyst to demonstrate compliance.

*****

D.1.~~12~~**14** Reporting Requirements

~~(a~~**(a)** **A quarterly summary of the information to document the compliance status with D.1.2 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.**

(b) 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:

****

(~~c~~**d**) 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**)

*****

Emissions Unit Description:

(b) One (1) natural gas-fired auxiliary boiler, identified as AUX, equipped with ultra-low-NOx burners, approved in 2026 for construction, with a rated maximum heat input capacity of 96 MMBtu per hour, and exhausting to stack AUX.

Under 40 CFR 60, Subpart Dc, AUX is an affected facility because it was constructed after June 9, 1989, has a maximum design heat input capacity of less than 100 MMBtu/hr, but greater than 10 MMBtu/hr, and is considered a small steam generating unit.

****

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

D.2.1 PSD BACT [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler shall be as follows:

(a) ~~The~~ PM, PM_{10}, and $PM_{2.5}$ emissions from the auxiliary boiler **(AUX)** shall be controlled through the use of pipeline-quality natural gas.

(b) PM, PM_{10}, and $PM_{2.5}$ emissions from the auxiliary boiler **(AUX)** shall be controlled through the use of good combustion practices.

(c) **Filterable** PM emissions from the auxiliary boiler **(AUX)** shall not exceed 0.~~0075~~**0019** lb/MMBtu~~, based on a 3 - hour average~~.

(d) PM_{10} emissions from the auxiliary boiler **(AUX)** shall not exceed 0.0075 lb/MMBtu~~, based on a 3 - hour average~~.

(e) $PM_{2.5}$ emissions from the auxiliary boiler **(AUX)** shall not exceed 0.0075 lb/MMBtu~~, based on a 3 - hour average~~.

(f) NOx emissions from the ~~Auxiliary Boiler~~**auxiliary boiler (AUX)** shall not exceed 0.~~037~~**011** lb/MMBtu~~, based on a 3-hour average~~.

(g) NOx emissions from the auxiliary boiler **(AUX)** shall be controlled by ~~a~~**an Ultra** Low NOx Burner.

(h) CO emissions from the ~~Auxiliary Boiler~~**auxiliary boiler (AUX)** shall not exceed 0.037 lb/MMBtu~~, based on a 3-hour average~~.

(i) CO emissions from the auxiliary boiler **(AUX)** shall be controlled through the use of good combustion practices.

(j) H_2SO_4 emissions from the ~~Auxiliary Boiler~~**auxiliary boiler (AUX)** shall not exceed 0.00014 lb/MMBtu~~, based on a 3 - hour average~~.

(k) H_2SO_4 emissions from the auxiliary boiler **(AUX)** shall be controlled through the use of only pipeline quality natural gas.

(l) ~~The GHG's BACT for the boiler shall be as follows:~~

~~(1)~~ CO_{2e} emissions from the ~~Auxiliary Boiler~~**auxiliary boiler (AUX)** shall not exceed 11,244 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(~~2~~**m**) CO_{2e} emissions from the ~~Auxiliary Boiler~~**auxiliary boiler (AUX)** shall be controlled through the use of good combustion practices.

(n) **The auxiliary boiler (AUX) shall not exceed 2,000 hours of operation per twelve (12) consecutive month period.**

****

D.2.3 Particulate Emissions [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating), PM emissions from the **natural gas-fired** auxiliary boiler **(AUX)** shall be limited to 0.~~33~~**28** pounds per MMBtu heat input.

****

D.2.5 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with ~~Condition~~**condition** D.2.1(n~~)(1~~), the following equation shall be used to determine the CO_{2e} emissions from the Auxiliary Boiler:

****

D.2.6 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Conditions D.2.1(c~~) through (e)~~**), (d),** and (~~j),~~**e), within 60 days after achieving the maximum production rate of the emission unit, but** not later than 180 days after the startup of ~~the~~**natural gas-fired** auxiliary boiler, the Permittee shall perform PM, PM_{10}, **and** $PM_{2.5}$ ~~and CO~~ testing of the natural gas-fired auxiliary boiler~~,~~ utilizing methods ~~as~~ approved by the ~~Commissioner~~**commissioner** at least once every five (5) years from the date of the most recent valid compliance demonstration. ~~PM_{10} and $PM_{2.5}$ include filterable and condensable PM.~~

(b) In order to demonstrate compliance with ~~Conditions D.2.1(f),~~**Condition D.2.1(f), within 60 days after achieving the maximum production rate of the emission unit, but** not later than 180 days after the startup of ~~the~~**natural gas-fired** auxiliary boiler, the Permittee shall perform **NOx testing of the natural gas-fired auxiliary boiler utilizing methods approved by the commissioner** at least once every five (5) years from the date of the most recent valid compliance demonstration.

(c) In order to demonstrate compliance with ~~Conditions~~**Condition** D.2.1(h)**, within 60 days after achieving the maximum production rate of the emission unit, but** not later than 180 days after the startup of ~~the~~**natural gas-fired** auxiliary boiler, the Permittee shall perform ~~VOC~~**CO** testing of the natural gas-fired auxiliary boiler~~,~~ utilizing methods ~~as~~ approved by the **commissioner at least once every five (5) years from the date of the most recent valid compliance demonstration.**

(e) **In order to demonstrate compliance with Condition D.2.1(j), within 60 days after achieving the maximum production rate of the emission unit, but not later than 180 days after the startup of natural gas-fired auxiliary boiler, the Permittee shall perform H_2SO_4 testing of the natural gas-fired auxiliary boiler utilizing methods approved by the commissioner** at least once every five (5) years from the date of the most recent valid compliance demonstration.

(e) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition. **PM_{10} and $PM_{2.5}$ includes filterable and condensable PM.**

D.2.7 Record Keeping ~~Requirements~~**Requirement**

(a) To document the compliance status with Condition D.2.1(~~n)(1~~**l**), the Permittee shall maintain ~~the monthly~~ records of the ~~total~~**monthly** CO_{2e} emissions from the **natural gas-fired** auxiliary ~~boilers~~**boiler**.

~~(b~~**(b)** **To document the compliance status with Condition D.2.1(n), the Permittee shall maintain records of the hours of operation of the natural gas-fired auxiliary boiler.**

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

D.2.8 Reporting Requirements

A quarterly **report of monthly CO_{2e} emissions and hours of operation and a quarterly** summary of the information to document the compliance status with ~~Condition~~**D.2.1(l) and** D.2.1(n~~)(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~~**33**).

*****

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(c) One (1) **diesel-fired** emergency generator ~~fueled with~~**using** ultra-low-sulfur-distillate (ULSD), identified as EG, approved in ~~2023~~**2026** for construction, with a maximum **output rating of 2,012** horsepower (hp) ~~of 2,012, displacement < 30 L/cylinder, using no control,~~ and exhausting to stack EG.

~~(d) One (1) 420-brake hp~~**Under 40 CFR 60, Subpart IIII, EG is an affected facility because it is a 2026 model year diesel-fired** emergency ~~fire pump fueled with ULSD,~~**stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and is not a fire pump engine.**

Under 40 CFR 63, Subpart ZZZZ, EG is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

(d) One (1) diesel-fired emergency fire pump engine using ultra-low-sulfur-distillate (ULSD), identified as FP, approved in ~~2023~~**2026** for construction, ~~using no control,~~**with a maximum output rating of 420 horsepower (hp),** and exhausting to stack ~~EF~~**FP**.

Under 40 CFR 60, Subpart IIII, FP is an affected facility because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, and was manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Under 40 CFR 63, Subpart ZZZZ, FP is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

(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 PSD BACT [326 IAC 2-2-3]

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the diesel-fired emergency generator **(EG)** and ~~ULSD fueled~~**the diesel-fired** emergency fire pump **(FP)** shall be as follows:

(a) The emissions from the emergency generator **(EG)** shall not exceed the limits in the table below, through the use of ~~good~~**state-of-the-art** combustion design.

~~Emission Unit~~	~~PM (g/hp-hr)~~	~~PM_{10} (g/hp-hr)~~	~~$PM_{2.5}$ (g/hp-hr)~~	~~SO_2 (lb/MMBtu)~~	~~NO_X + NMHC (g/hp-hr)~~	~~CO (g/hp-hr)~~
~~EG~~	~~0.15~~	~~0.15~~	~~0.15~~	~~0.0016~~	~~4.8~~	~~2.6~~

	PM	**PM_{10}**	**$PM_{2.5}$**	**NOx + NMHC**	**CO**
Emission Limit (g/hp-hr)	**0.15**	**0.15**	**0.15**	**4.8**	**2.61**
Emission Limit	**0.67**	**0.67**	**0.67**	**21.29**	**11.58**

(lb/hr)					

(b) The emissions from the emergency fire pump **engine (FP)** shall not exceed the limits in the table below, through the use of **state-of-the-art** combustion design.

~~Emission Unit~~	~~PM (g/kW-hr)~~	~~PM_{10} (g/kW-hr)~~	~~$PM_{2.5}$ (g/kW-hr)~~	~~SO_2 (lb/MMBtu)~~	~~H_2SO_4 (lb/MMBtu)~~	~~NO_X + NMHC (g/kW-hr)~~	~~CO (g/kW-hr)~~
~~FP~~	~~0.20~~	~~0.20~~	~~0.20~~	~~0.0016~~	~~0.0002~~	~~4.0~~	~~3.5~~

	PM	**PM_{10}**	**$PM_{2.5}$**	**NOx + NMHC**	**CO**
Emission Limit (g/kW-hr)	**0.20**	**0.20**	**0.20**	**4.0**	**3.5**
Emission Limit (lb/hr)	**0.14**	**0.14**	**0.14**	**2.72**	**2.38**

(c) The sulfur content of diesel fuel burned in the emergency generator **(EG)** shall not exceed 0.0015%.

(d) The sulfur content of diesel fuel burned in the emergency fire **water** pump **engine (FP)** shall not exceed 0.0015~~%~~**%.**

(e) The GHG BACT for the emergency generator **(EG)** shall be as follows:

(1) The use of a good engineering design and fuel~~-~~**-**efficient design; and

(2) The CO_2e emissions from EG shall not exceed ~~625~~**125** tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(f) The GHG BACT for the emergency fire **water** pump **engine (FP)** shall be as follows:

(1) The use of a good engineering design and fuel~~-~~**-**efficient design; and

(2) ~~The~~ CO_{2e} emissions from ~~FP~~ **the emergency fire pump** shall not exceed ~~123~~ **24** tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

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

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

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

D.3.4 Greenhouse Gases (~~GHG's~~**GHGs**) Calculations

To determine compliance with Conditions D.3.1(e)(2) and D.3.1(f)(2), the following equation shall be used to determine the CO_{2e} emissions from the **diesel-fired** emergency ~~diesel engine~~**generator** and **the diesel-fired emergency** fire pump **engine**:

****

D.3.5 Record Keeping Requirement

(a) ~~In order to~~**To** document the compliance status with Conditions D.3.1(a), (b), (c), and (d~~)~~**),** the Permittee shall maintain the following monthly records for the diesel-fired emergency generator and **the** diesel-fired emergency fire pump engine.

(1) the percent sulfur content of the fuel used in each unit.

(2) the total amount of fuel used in each unit.

(b) To document the compliance status with Conditions D.3.1(e)(2) and D.3.1(f)(2), the Permittee shall maintain records of the monthly CO_{2e} emissions from the diesel-fired emergency generator and the diesel-fired emergency fire pump engine.

(c) To document **the** compliance **status** with Condition D.3.2, the Permittee shall maintain monthly records of hours of operation of the diesel-fired emergency generator and **the diesel-fired** emergency fire pump **engine**.

****

D.3.6 Reporting Requirements

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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~~**33**).

*****

SECTION E.1 NSPS

Emissions Unit Description:

(b) One (1) natural gas-fired auxiliary boiler, identified as AUX, equipped with **ultra-l**ow-NOx burners, approved in ~~2023~~**2026** for construction, with a **rated** maximum heat input capacity of 96 MMBtu per hour~~, using no add-on control~~, and exhausting to stack AUX.

Under 40 CFR ~~Part~~ 60, Subpart Dc, ~~this unit~~**AUX** is ~~considered~~ an affected facility **because it was constructed after June 9, 1989, has a maximum design heat input capacity of less than 100 MMBtu/hr, but greater than 10 MMBtu/hr, and is considered a small steam generating unit**.

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

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

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

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart 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**
~~MC 61-53 IGCN 1003~~
Indianapolis, Indiana 46204-2251

E.1.2 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 A to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

~~(1) 40 CFR 60.40c(a) - (d)~~
~~(2) 40 CFR 60.41c~~
~~(3) 40 CFR 60.48c(a)(1), (3), (g), & (i)~~

60.40c	**Applicability and delegation of authority.**
60.41c	**Definitions.**
60.48c(a)(1), (a)(3), (g), and (i)	**Reporting and recordkeeping requirements.**

SECTION E.2 NSPS

Emissions Unit Description:

(c) One (1) **diesel-fired** emergency generator ~~fueled with~~**using** ultra-low-sulfur-distillate (ULSD), identified as EG, approved in ~~2023~~**2026** for construction, with a maximum **output rating of 2,012** horsepower (hp) ~~of 2,012, displacement < 30 L/cylinder, using no control,~~ and exhausting to stack EG.

Under 40 CFR ~~Part~~ 60, Subpart IIII, ~~this unit~~**EG** is ~~considered~~ an affected facility~~.~~ **because it is a 2026 model year diesel-fired** ~~CFR Part 63, Subpart ZZZZ, this unit is considered a new affected source.~~

~~(d) One (1) 420-brake hp~~ emergency **stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and is not a fire pump engine.**

Under 40~~fire pump fueled with ULSD,~~ **CFR 63, Subpart ZZZZ, EG is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.**

(d) **One (1) diesel-fired emergency fire pump engine using ultra-low-sulfur-distillate (ULSD),** identified as FP, approved in ~~2023~~**2026** for construction, ~~using no control,~~**with a maximum output rating of 420 horsepower (hp),** and exhausting to stack ~~EF~~**FP**.

Under 40 CFR ~~Part~~ 60, Subpart IIII, ~~this unit~~**FP** is ~~considered~~ an affected facility **because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, and was manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006**.

Under 40 CFR ~~Part~~ 63, Subpart ZZZZ, ~~this unit~~**FP is an affected facility because it was constructed after June 12, 2006, and** is considered a new ~~affected~~ **emergency stationary reciprocating internal combustion engine (RICE) at an area** source **of HAPs**.

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

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

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

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

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

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
Indiana Government Center North
100 North Senate Avenue**, Room 13W**
~~MC 61-53 IGCN 1003~~
Indianapolis, Indiana 46204-2251

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

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

(a) ~~Diesel-Fired Emergency Generator~~ EG~~ ~~

~~(1) 40 CFR 60.4200(a)(2)(i) & (4)~~
~~(2) 40 CFR 60.4205(b)~~
~~(3) 40 CFR 60.4206~~
~~(4) 40 CFR 60.4207(b)~~
~~(5) 40 CFR 60.4208(a)~~
~~(6) 40 CFR 60.4209(a)~~
~~(7) 40 CFR 60.4211(a), (c), (f)(1), (2)(i), (3), & (g)(3)~~
~~(8) 40 CFR 60.4214(b)~~
~~(9) 40 CFR 60.4218~~
~~(10) 40 CFR 60.4219~~
~~(11) Tables 5 and 8~~

60.4200(a)(2)(i), (a)(4), (c)	**Am I subject to this subpart?**
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(a)	**What is the deadline for importing or installing stationary CI ICE produced in previous model years?**
60.4209(a)	**What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?**
60.4211(a), (c), (f), (g)(3)	**What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?**
60.4214(b) and (d)	**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 5	**Labeling and Recordkeeping Requirements for New Stationary Emergency Engines**
Table 8	**Applicability of General Provisions to Subpart IIII**

(b) ~~Diesel-Fired Emergency Fire Pump Engine~~ FP

~~(1) 40 CFR 60.4200(a)(2)(i) & (4)~~
~~(2) 40 CFR 60.4205(c)~~
~~(3) 40 CFR 60.4206~~
~~(4) 40 CFR 60.4207(b)~~
~~(5) 40 CFR 60.4209(a)~~
~~(6) 40 CFR 60.4211(a), (c), (f)(1), (2)(i), (3), & (g)(2)~~

~~(7) 40 CFR 60.4218~~
~~(8) 40 CFR 60.4219~~
~~(9) Table 4~~
~~(10) Table 8~~

60.4200(a)(2)(ii), (a)(4), (c)	**Am I subject to this subpart?**
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?**
60.4209(a)	**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?**
60.4218	**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 4	**Emission Standards for Stationary Fire Pump Engines**
Table 8	**Applicability of General Provisions to Subpart IIII**

SECTION E.3 NSPS

~~Option 1: Siemens Model SCC6-9000HL Turbine~~

~~(a1) One (1) natural gas-fired combined cycle system, identified as CTGA, approved in 2023 for construction, with a maximum heat input capacity of 3,800 MMBtu per hour, equipped with a Siemens combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG), using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.~~

~~Under 40 CFR Part 60, Subpart KKKK, this unit considered an affected facility.~~
~~Under 40 CFR Part 60, Subpart TTTT, this unit is considered an affected facility.~~

~~or~~

~~Option 2: GE Model 7HA.03Turbine~~

(a~~2~~) One (1) natural gas-fired combined cycle system, identified as ~~CTGB~~**CTG-01**, approved in ~~2023~~ **2026** for construction, with a maximum heat input capacity of ~~4,200~~**4,253** MMBtu per hour, equipped with a GE combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG) **and one air-cooled condenser (ACC)**, using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and

CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.

Under 40 CFR 60, Subpart KKKK, CTG-01 was constructed after February 18, 2005, has a maximum heat input capacity of greater than 10 MMBtu/hr, and is a stationary combustion turbine (CTG).

Under 40 CFR 60, Subpart TTTTa, CTG-01 was constructed after May 23, 2023, has a base load rating greater than 250 MMBtu/hr of fossil fuel, and serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system, and is an affected unit.

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E.3.2 Stationary Combustion Turbines NSPS [326 IAC 12] [40 CFR Part 60, Subpart KKKK]

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

~~(1) 40 CFR 60.4300~~
~~(2) 40 CFR 60.4305~~
~~(3) 40 CFR 60.4315~~
~~(4) 40 CFR 60.4320(a)~~
~~(5) 40 CFR 60.4330(a)~~
~~(6) 40 CFR 60.4333~~
~~(7) 40 CFR 60.4340(b)~~
~~(8) 40 CFR 60.4345~~
~~(9) 40 CFR 60.4350~~
~~(10) 40 CFR 60.4360~~
~~(11) 40 CFR 60.4365(a)~~
~~(12) 40 CFR 60.4375(a)~~
~~(13) 40 CFR 60.4380(b)~~
~~(14) 40 CFR 60.4395~~
~~(15) 40 CFR 60.4405~~
~~(16) 40 CFR 60.4410~~
~~(17) 40 CFR 60.4420~~
~~(18) Table 1~~

60.4300	**What is the purpose of this subpart?**
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(b)	**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?**
60.4360	**How do I determine the total sulfur content of the turbine's combustion fuel?**
60.4365(a)	**How can I be exempted from monitoring the total sulfur content of the fuel?**
60.4375(a)	**What reports must I submit?**

60.4380(b) and (c)	**How are excess emissions and monitor downtime defined for NOX?**
60.4385	**How are excess emissions and monitoring downtime defined for SO2?**
60.4395	**When must I submit my reports?**
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**

SECTION E.4 NSPS

~~Option 1: Siemens Model SCC6-9000HL Turbine~~

~~(a1) One (1) natural gas-fired combined cycle system, identified as CTGA, approved in 2023 for construction, with a maximum heat input capacity of 3,800 MMBtu per hour, equipped with a Siemens combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG), using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.~~

~~Under 40 CFR Part 60, Subpart KKKK, this unit considered an affected facility.~~
~~Under 40 CFR Part 60, Subpart TTTT, this unit is considered an affected facility.~~

~~or~~

~~Option 2: GE Model 7HA.03Turbine~~

(a~~2~~) One (1) natural gas-fired combined cycle system, identified as ~~CTGB~~**CTG-01**, approved in ~~2023~~ **2026** for construction, with a maximum heat input capacity of ~~4,200~~**4,253** MMBtu per hour, equipped with a GE combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG) **and one air-cooled condenser (ACC)**, using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.

Under 40 CFR 60, Subpart KKKK, CTG-01 was constructed after February 18, 2005, has a maximum heat input capacity of greater than 10 MMBtu/hr, and is a stationary combustion turbine (CTG).

Under 40 CFR 60, Subpart TTTTa, CTG-01 was constructed after May 23, 2023, has a base load rating greater than 250 MMBtu/hr of fossil fuel, and serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system, and is an affected unit.

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 TTTT**a**.

(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.4.2 Greenhouse Gas Emissions for ~~Electric Generating Units~~**Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units** NSPS [326 IAC 12] [40 CFR Part 60, Subpart TTTT**a**]

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

60.5508a	**What is the purpose of this subpart?**
60.5509a	**Am I subject to this subpart?**
60.5515a(a)	**Which pollutants are regulated by this subpart?**
60.5520a(a), (b)	**What CO_2 emissions standard must I meet?**
60.5525a(a), (b), & (c)(1)	**What are my general requirements for complying with this subpart?**
60.5535a(a), (c), (d)	**How do I monitor and collect data to demonstrate compliance?**
60.5540a	**How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?**
60.5550a	**What notifications must I submit and when?**
60.5555a (a), (b), (c)(1), (c)(3)(i), (c)(4), & (d)	**What reports must I submit and when?**
60.5560a (a), (c), (d), (e), (f), & (g)	**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 60.5508~~
~~(2) 40 CFR 60.5509~~
~~(3) 40 CFR 60.5515(a)~~
~~(4) 40 CFR 60.5520(a) & (b)~~
~~(5) 40 CFR 60.5525(a), (b), & (c)(1)~~
~~(6) 40 CFR 60.5535(a), (c), (d)~~
~~(7) 40 CFR 60.5540~~
~~(8) 40 CFR 60.5550~~
~~(9) 40 CFR 60.5555(a), (b), (c)(1), (c)(3)(i), (c)(4), & (d)~~
~~(10) 40 CFR 60.5560(a), (c), (d), (e), (f), & (g)~~
~~(11) 40 CFR 60.5565~~
~~(12) 40 CFR 60.5570~~
~~(13) 40 CFR 60.5575~~
~~(14) 40 CFR 60.5580~~
~~(15) Table 2~~
~~(16) Table 3~~

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SECTION E.5 NESHAP

Emissions Unit Description:

(c) One (1) **diesel-fired** emergency generator ~~fueled with~~**using** ultra-low-sulfur-distillate (ULSD), identified as EG, approved in ~~2023~~**2026** for construction, with a maximum **output rating of 2,012** horsepower (hp) ~~of 2,012, displacement < 30 L/cylinder, using no control,~~ and exhausting to stack EG.

Under 40 CFR ~~Part~~ 60, Subpart IIII, ~~this unit~~**EG** is ~~considered~~ an affected facility~~.~~
~~Under 40 CFR Part 63, Subpart ZZZZ, this unit is considered a new affected source.~~

~~(d) One (1) 420-brake hp~~ **because it is a 2026 model year diesel-fired** emergency **stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and is not a fire pump engine.**

Under 40~~fire pump fueled with ULSD,~~ **CFR 63, Subpart ZZZZ, EG is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.**

(d) One (1) diesel-fired emergency fire pump engine using ultra-low-sulfur-distillate (ULSD), identified as FP, approved in ~~2023~~**2026** for construction, ~~using no control,~~**with a maximum output rating of 420 horsepower (hp),** and exhausting to stack ~~EF~~**FP**.

Under 40 CFR ~~Part~~ 60, Subpart IIII, ~~this unit~~**FP** is ~~considered~~ an affected facility **because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, and was manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006**.

Under 40 CFR ~~Part~~ 63, Subpart ZZZZ, ~~this unit~~**FP is an affected facility because it was constructed after June 12, 2006, and** is considered a new ~~affected~~ **emergency stationary reciprocating internal combustion engine (RICE) at an area** source **of HAPs**.

(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.5.1 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**
~~MC 61-53 IGCN 1003~~
Indianapolis, Indiana 46204-2251

E.5.2 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 E to the operating permit), which are incorporated by reference as 326 IAC 20-82 for the emission unit(s) listed above:

~~(1) 40 CFR 63.6580~~
~~(2) 40 CFR 63.6585(a), (c), & (d)~~
~~(3) 40 CFR 63.6590(a)(2)(iii) & (c)(1)~~
~~(4) 40 CFR 63.6665~~
~~(5) 40 CFR 63.6670~~
~~(6) 40 CFR 63.6675~~

63.6580	**What is the purpose of subpart ZZZZ?**
63.6585	**Am I subject to this subpart?**
63.6590(a)(2)(iii) and (c)(1)	**What parts of my plant does this subpart cover?**
63.6595(a)(7)	**When do I have to comply with this subpart?**
63.6665	**What parts of the General Provisions apply to me?**
63.6670	**Who implements and enforces this subpart?**
63.6675	**What definitions apply to this subpart?**

SECTION F CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, and CSAPR SO_2 Group 1 Trading Program~~, CSAPR SO_2 Group 1 Trading Program, & CSAPR NOx Ozone Season Group 3 Trading Program~~ Requirements (40 CFR 97.406), (40 CFR 97.~~506~~806) (Group 3 Trading Program stayed per 89 FR 87960, 11/6/24), (40 CFR 97.606~~), (40 CFR 97.1006~~)

ORIS Code: 57794

Emissions Unit Description:

~~Option 1: Siemens Model SCC6-9000HL Turbine~~

~~(a1~~**(a)** One (1) natural gas-fired combined cycle system, identified as ~~CTGA~~**CTG-01**, approved in ~~2023~~**2026** for construction, with a maximum heat input capacity of ~~3,800~~**4,200** MMBtu per hour, equipped with a ~~Siemens~~**GE** combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG**) and one air-cooled condenser (ACC**), using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.

Under 40 CFR ~~Part~~ 60, Subpart KKKK, ~~this unit considered an affected facility.~~
~~Under 40 CFR Part 60, Subpart TTTT, this unit is considered an affected facility.~~

~~or~~

~~tion 2: GE Model 7HA.03Turbine~~

~~(a2) One (1) natural gas-fired combined cycle system, identified as CTGB, approved in 2023 for construction, with~~**CTG-01 was constructed after February 18, 2005, has** a maximum heat input capacity of ~~4,200~~**greater than 10** MMBtu~~ per hour, equipped with a GE~~**/hr, and is a stationary** combustion turbine ~~generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG), using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG with continuous emissions monitors for NOx and CO.~~**(CTG).**

~~Under 40 CFR Part 60, Subpart KKKK, this unit considered an affected facility.~~
~~Under 40 CFR Part 60, Subpart TTTT, this unit is considered an affected facility.~~
Under 40 CFR 60, Subpart TTTTa, CTG-01 was constructed after May 23, 2023, has a base load rating greater than 250 MMBtu/hr of fossil fuel, and serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system, and is an affected unit.

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

F.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:

~~(1) 40 CFR 97.413 through 97.418;~~
~~(2) 40 CFR 97.513 through 97.518;~~
~~(3) 40 CFR 97.613 through 97.618; and~~
~~(4) 40 CFR 97.1013 through 97.1018.~~

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.**

F.2 Emissions Monitoring, Reporting, and Recordkeeping Requirements

(a) The owners and operators, and the designated representative, of each CSAPR NO_X Annual source, CSAPR NOx Ozone Season **Group 2** source, and CSAPR SO2 Group 1 source, and each CSAPR NO_X Annual unit at the source, CSAPR NOx Ozone Season **Group 2** unit at the source, and CSAPR SO2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430, 40 CFR 97.~~530, 40 CFR 97.630~~**830**, and 40 CFR 97.~~1030~~**630** (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431, 97.~~531, 97.631~~**831**, and 97.~~1031~~**631** (initial monitoring system certification and recertification procedures), 97.432, 97.~~532, 97.632~~**832**, and 97.~~1032~~ **632** (monitoring system out-of-control periods), 97.433, 97.~~533~~**833**, and 97.633 (notifications concerning monitoring), 97.434, 97.~~534, 97.634~~**834**, and 97.~~1034~~**634** (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435, 97.~~535, 97.635~~**835**, and 97.~~1035~~**635** (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(b) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of CSAPR 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 CSAPR NO_X Annual emissions limitation and assurance provisions under Condition F.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.

(c) The emissions data determined in accordance with 40 CFR 97.~~530~~**830** through 97.~~535~~**835** shall be used to calculate allocations of CSAPR NO_X Ozone Season **Group 2** allowances under 40 CFR 97.~~511(a)(2)~~**811** and (b) and 97.~~512~~**812** and to determine compliance with the CSAPR NO_X Ozone Season **Group 2** emissions limitation and assurance provisions under Condition F.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.~~530~~**830** through 97.~~535~~**835** and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(d) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of CSAPR 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 CSAPR SO_2 Group 1 emissions limitation and assurance provisions under Condition F.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.

~~(c) The emissions data determined in accordance with 40 CFR 97.1030 through 97.1035 shall be used to calculate allocations of CSAPR NO_X Ozone Season Group 3 allowances under 40 CFR 97.1011(a)(2) and (b) and 97.1012 and to determine compliance with the CSAPR NO_X Ozone Season Group 3 emissions limitation and assurance provisions under Condition F.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 97.1030 through 97.1035 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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F.4 NO_X Ozone Season **Group 2** Requirements

(a) CSAPR NO_X Ozone Season **Group 2** emissions limitation**.**

(1) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season **Group 2** source and each CSAPR NO_X Ozone Season **Group 2** unit at the source shall hold, in the source's compliance account, CSAPR NO_X Ozone Season **Group 2** allowances available for deduction for such control period under 40 CFR 97.~~524~~**824**(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Ozone Season **Group 2** units at the source.

(2) If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season **Group 2** units at a CSAPR NO_X Ozone Season **Group 2** source are in excess of the CSAPR NO_X Ozone Season **Group 2** emissions limitation set forth in Condition F.4(a)(1) above, then:

(A) The owners and operators of the source and each CSAPR NO_X Ozone Season **Group 2** unit at the source shall hold the CSAPR NO_X Ozone Season **Group 2** allowances required for deduction under 40 CFR 97.~~524~~**824**(d); and

(B) The owners and operators of the source and each CSAPR 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 ~~BBBBB~~**EEEEE** and the Clean Air Act.

(b) CSAPR NO_X Ozone Season **Group 2** assurance provisions**.**

(1) If total NO_X emissions during a control period in a given year from all CSAPR NO_X Ozone Season **Group 2** units at CSAPR 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) CSAPR NO_X Ozone Season **Group 2** allowances available for deduction for such control period under 40 CFR 97.~~525~~**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.~~525~~**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 exceeds the respective common designated representative's assurance level; and

(B) The amount by which total NO_X emissions from all CSAPR NO_X Ozone Season **Group 2** units at CSAPR NO_X Ozone Season **Group 2** sources in the state for such control period exceed the state assurance level.

(2) The owners and operators shall hold the CSAPR NO_X Ozone Season **Group 2** allowances required under Condition F.4(b)(1) 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.

(3) Total NO_X emissions from all CSAPR NO_X Ozone Season **Group 2** units at CSAPR 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.~~510~~**810**(a) and the state's variability limit under 40 CFR 97.~~510~~**810**(b).

(4) It shall not be a violation of 40 CFR part 97, subpart ~~BBBBB~~**EEEEE** or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Ozone Season **Group 2** units at CSAPR 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 CSAPR NO_X Ozone Season **Group 2** units at CSAPR NO_X Ozone Season **Group 2** sources in the state during a control period exceeds the common designated representative's assurance level.

(5) To the extent the owners and operators fail to hold CSAPR NO_X Ozone Season **Group 2** allowances for a control period in a given year in accordance with Conditions F.4(b)(1) through (3) 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 CSAPR NOX Ozone Season **Group 2** allowance that the owners and operators fail to hold for such control period in accordance with Conditions F.4(b)(1) through (3) above and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart ~~BBBBB~~**EEEEE** and the Clean Air Act.

(c) Compliance Periods**.**

(1) A CSAPR NOx Ozone Season unit shall be subject to the requirements under Condition F.4(a) 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.~~530~~**830**(b) and for each control period thereafter.

(2) A CSAPR NOx Ozone Season **Group 2** unit shall be subject to the requirements under Condition F.4(b) 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.~~530~~**830**(b) and for each control period thereafter.

(d) Vintage of allowances held for compliance**.**

(1) A CSAPR NOx Ozone Season **Group 2** allowance held for compliance with the requirements under Condition F.4(a)(1) above for a control period in a given year must be a CSAPR NOx Ozone Season **Group 2** Allowance that was allocated for such control period or a control period in a prior year.

(2) A CSAPR NOx Ozone Season **Group 2** allowance held for compliance with the requirements under Conditions F.4(a)(2)(A) and (b)(1) through (3) above for a control period in a given year must be a CSAPR NOx Ozone Season **Group 2** 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.

(e) Allowances Management System Requirements**.**

(1) Each CSAPR 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 ~~BBBBB~~**EEEEE**.

(f) Limited Authorization**.**

(1) A CSAPR 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 CSAPR NOx Ozone Season **Group 2** Trading Program; and

(B) Notwithstanding any other provision of 40 CFR Part 97, Subpart ~~BBBBB~~**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.

(g) Property Right**.**

(1) A CSAPR NOx Ozone Season **Group 2** allowance does not constitute a property right.

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F.5 SO_2 Emissions Requirements

(a) CSAPR SO_2 Group 1 emissions limitation**.**

****

(c) Compliance periods**.**

(1) A CSAPR SO_2 Group 1 unit shall be subject to the requirements under Condition F.5(a) 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.**

(2) A CSAPR SO_2 Group 1 unit shall be subject to the requirements under Condition F.5(b) 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.

~~(2) A CSAPR SO_2 Group 1 unit shall be subject to the requirements under Condition F.5(b) 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.~~

****

F.6 Title V Permit Revision Requirements

(a) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_X Annual allowances in accordance with 40 CFR Part 97, Subpart AAAAA, CSAPR NO_X Ozone Season allowances in accordance with 40 CFR Part 97, Subpart ~~BBBBB,~~ **EEEEE, and** CSAPR SO_2 Group 1 allowances in accordance with 40 CFR Part 97, Subpart CCCCC~~, and CSAPR NOx Ozone Season Group 3 allowances in accordance with 40 CFR Part 97, Subpart GGGGG~~.

(b) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, 40 CFR 97.~~530~~**830** through 97.~~535,~~**835, and** 40 CFR 97.630 through 97.635~~, and 40 CFR 97.1030 through 97.1035~~, 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 CSAPR 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.~~506(d)(2), 40 CFR 97.606~~**806**(d)(2), and 40 CFR 97.~~1006~~**606**(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

F.7 Additional recordkeeping and reporting requirements

(a) Unless otherwise provided, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit, CSAPR NO_X Ozone Season **Group 2** source and each CSAPR NO_X Ozone Season **Group 2** unit, and CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source~~, and CSAPR NOx Ozone Season Group 3 source and each CSAPR NOx Ozone Season Group 3 unit~~ 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.

(1) The certificate of representation under 40 CFR 97.416, 40 CFR 97.~~516, 40 CFR 97.616~~**816**, and 40 CFR 97.~~1016,~~**616** for the designated representative for the source and each CSAPR NO_X Annual unit, CSAPR NOx Ozone Season ~~unit, CSAPR SO_2~~ Group ~~1~~**2** unit, and CSAPR ~~NOx Ozone Season~~**SO_2** Group ~~3~~**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.~~516, 40 CFR 97.616~~**816**, and 40 CFR 97.~~1016~~**616** changing the designated representative.

(2) All emissions monitoring information, in accordance with 40 CFR Part 97, Subpart AAAAA, 40 CFR Part 97, Subpart ~~BBBBB, 40 CFR Part 97, Subpart CCCCC~~**EEEEE**, and 40 CFR Part 97, Subpart ~~GGGGG~~**CCCCC**.

(3) 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 CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season ~~Trading Program, CSAPR SO_2~~ Group ~~1~~**2** Trading Program, and CSAPR ~~NOx Ozone Season~~**SO_2** Group ~~3~~**1** Trading Program.

(b) The designated representative of a CSAPR NO_X Annual source and each CSAPR NO_X Annual unit, a CSAPR NO_X Ozone Season **Group 2** source and each CSAPR NO_X Ozone Season **Group 2** unit, **and** a CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 ~~unit, and CSAPR NOx Ozone Season Group 3 source and each CSAPR NOx Ozone Season Group 3~~ unit at the source shall make all submissions required under the CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season **Group 2** Trading Program, **and** CSAPR SO_2 Group 1 Trading Program, ~~and CSAPR NOx Ozone Season Group 3 Trading Program~~ except as provided in 40 CFR 97.418, 40 CFR 97.~~518, 40 CFR 97.618~~**818**, and 40 CFR 97.~~1018~~**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.

F.8 Liability

(a) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual source or the designated representative of a CSAPR NO_X Annual source shall also apply to the owners and operators of such source and of the CSAPR NO_X Annual units at the source.

(b) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual unit or the designated representative of a CSAPR NO_X Annual unit shall also apply to the owners and operators of such unit.

(c) Any provision of the CSAPR NO_X Ozone Season **Group 2** Trading Program that applies to a CSAPR NO_X Ozone Season **Group 2** source or the designated representative of a CSAPR NO_X Ozone Season **Group 2** source shall also apply to the owners and operators of such source and of the CSAPR NO_X Ozone Season **Group 2** units at the source.

(d) Any provision of the CSAPR NO_X Ozone Season **Group 2** Trading Program that applies to a CSAPR NO_X Ozone Season **Group 2** unit or the designated representative of a CSAPR NO_X Ozone Season **Group 2** unit shall also apply to the owners and operators of such unit.

(e) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 source or the designated representative of a CSAPR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the CSAPR SO_2 Group 1 units at the source.

(f) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 unit or the designated representative of a CSAPR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

~~(g) Any provision of the CSAPR NOx Ozone Season Group 3 Trading Program that applies to a CSAPR NOx Ozone Season Group 3 source or the designated representative of a CSAPR NOx Ozone Season Group 3 source shall also apply to the owners and operators of such source and of the CSAPR NOx Ozone Season Group 3 units at the source.~~

~~(h) Any provision of the CSAPR NOx Ozone Season Group 3 Trading Program that applies to a CSAPR NOx Ozone Season Group 3 unit or the designated representative of a CSAPR NOx Ozone Season Group 3 unit shall also apply to the owners and operators of such unit.~~

F.9 Effect on Other Authorities

No provision of the CSAPR NO_X Annual Trading Program or exemption under 40 CFR 97.405, CSAPR NO_X Ozone Season Group ~~1~~**2** Trading Program or exemption under 40 CFR 97.~~505,~~**805, and** CSAPR SO_2 Group 1 Trading Program or exemption under 40 CFR 97.605~~, and CSAPR NOx Ozone Season Group 3 Trading Program or exemption under 40 CFR 97.1005,~~ shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Annual source or CSAPR NO_X Annual unit, CSAPR NO_X Ozone Season **Group 2** source or CSAPR NO_X Ozone Season **Group 2** unit, **and** CSAPR SO_2 Group 1 source or CSAPR SO_2 Group 1 unit~~, and CSAPR NOx Ozone Season Group 3 source or CSAPR NOx Ozone Season Group 3 unit,~~ from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

F.10 Description of CSAPR Monitoring Provisions

The CSAPR 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 CSAPR NOx Annual Trading Program, CSAPR NOx Ozone Season Trading Program, **and** CSAPR SO2 Group 1~~ Trading Program, and CSAPR NOx Ozone Season Group 3~~ Trading Program.

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~~**TR** NO_X Annual Trading Program), 97.~~530~~**830** through 97.~~535 (CSAPR~~**835 (TR** NO_X Ozone Season **Group 2** Trading Program), **and** 97.630 through 97.635 (~~CSAPR~~**TR** SO_2 Group 1 Trading Program), ~~and 97.1030 through 97.1035 (CSAPR NOx Ozone~~

~~Season Group 3 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~~**835** (CSAPR NO_X Ozone Season **Group 2** Trading Program), **and** 97.635 (CSAPR SO_2 Group 1 Trading Program), ~~and 97.1035 (CSAPR NOx Ozone Season Group 3 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~~**830** through 97.~~534~~**834** (CSAPR NO_X Ozone Season **Group 2** Trading Program), **and** 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program), ~~and 97.1030 through 97.1034 (CSAPR NOx Ozone Season Group 3 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~~**835** (CSAPR NO_X Ozone Season **Group 2** Trading Program), **and** 97.635 (CSAPR SO_2 Group 1 Trading Program), ~~and 97.1035 (CSAPR NOx Ozone Season Group 3 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~~**830** through 97.~~534~~**834** (CSAPR NO_X Ozone Season **Group 2** Trading Program), **and** 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program), ~~and 97.1030 through 97.1034 (CSAPR NOx Ozone Season Group 3 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.

~~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: Maple Creek Energy LLC~~
~~Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana~~
~~Part 70 Permit No.: T153-45909-00056~~

~~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:	**Maple Creek Energy LLC**
Source Address:	**W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849**
Permit No.:	**T153-45909-00056**

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.

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

Part 70 Quarterly Report

Source Name:	Maple Creek Energy LLC
Source Address:	W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana **47849**
Part 70 Permit No.:	**T153-45909-00056**
Facility:	**Natural Gas-Fired Combined Cycle Combustion Turbine (CTG-01)**
Parameter:	**PM emissions**
Limit:	**The PM emissions from the combined startup and shutdown events from the Natural Gas-Fired Combined Cycle Combustion Turbine (CTG-01) shall not exceed 1.9 tons per twelve (12) consecutive month period.**

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: ____

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

Part 70 Quarterly Report

Source Name: **Maple Creek Energy LLC**
Source Address: **W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849**
Part 70 Permit No.: T153-45909-00056
Facility: **Natural Gas-Fired** Combined Cycle Combustion Turbine (~~Siemens~~**CTG-01**)
Parameter: **PM_{10} emissions**
Limit: **The PM_{10} emissions from the combined startup and shutdown events from the Natural Gas-Fired Combined Cycle Combustion Turbine (CTG-01) shall not exceed 1.9 tons per twelve (12) consecutive month period.**

QUARTER:______________________ YEAR:______________________

Month	Column 1	Column 2	Column 1 + Column 2
	PM_{10} Emissions (tons)	**PM_{10} Emissions (tons)**	**PM_{10} 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: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana **47849**
Part 70 Permit No.: T153-45909-00056
Facility: **Natural Gas-Fired Combined Cycle Combustion Turbine (CTG-01)**
Parameter: **$PM_{2.5}$ emissions**
Limit: **The $PM_{2.5}$ emissions from the combined startup and shutdown events from the Natural Gas-Fired Combined Cycle Combustion Turbine (CTG-01) shall not exceed 1.9 tons per twelve (12) consecutive month period.**

QUARTER:____________________ YEAR:____________________

Month	Column 1	Column 2	Column 1 + Column 2
	$PM_{2.5}$ Emissions (tons)	**$PM_{2.5}$ Emissions (tons)**	**$PM_{2.5}$ 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:____

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

Part 70 Quarterly Report

Source Name: **Maple Creek Energy LLC**
Source Address: **W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849**
Part 70 Permit No.: T153-45909-00056
Facility: **Natural Gas-Fired Combined Cycle Combustion Turbine (CTG-01)**
Parameter: VOC emissions
Limit: The VOC emissions from the ~~CCCT shall not exceed 29.3~~**combined startup and shutdown events from the Natural Gas-Fired Combined Cycle Combustion Turbine (CTG-01) shall not exceed 18.8** tons per twelve (12) consecutive month period.

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:____

~~**OFFICE OF AIR QUALITY**~~
~~**COMPLIANCE AND ENFORCEMENT BRANCH**~~

~~**Part 70 Quarterly Report**~~

~~Source Name:~~ ~~Maple Creek Energy LLC~~
~~Source Address:~~ ~~W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana~~
~~Facility:~~ ~~Combined Cycle Combustion Turbine (GE)~~
~~Parameter:~~ ~~VOC emissions~~
~~Limit:~~ ~~The VOC emissions from the CCCT shall not exceed 18.8 tons per twelve (12) consecutive month period.~~

	~~VOC Emissions (tons)~~	~~VOC Emissions (tons)~~	~~VOC Emissions (tons)~~

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

Part 70 Quarterly Report

Source Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana **47849**
~~Facility:~~ ~~Combined Cycle Combustion Turbine (Siemens)~~
~~Parameter:~~ ~~CO2e emissions~~
~~Limit:~~ ~~The CO2e emissions from the CCCT shall not exceed 2,040,335 tons per twelve (12) consecutive month period.~~

	~~CO2e Emissions (tons)~~	~~CO2e Emissions (tons)~~	~~CO2e Emissions (tons)~~

Part 70 Permit No.: T153-45909-00056
Facility: **Natural Gas-Fired** Combined Cycle Combustion Turbine (~~GE~~**CTG-01**)
Parameter: CO2e emissions
~~Parameter:~~ ~~CO2e emissions~~
Limit: The CO2e emissions from the ~~CCCT~~**Natural Gas-Fired Combined Cycle Combustion Turbine (CTG)** shall not exceed 2,~~292,966~~**065,094** tons per twelve (12) consecutive month period.

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

~~Part 70 Quarterly Report~~

~~Source Name:~~ ~~Maple Creek Energy LLC~~
~~Source Address:~~ ~~W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana~~
~~Part 70 Permit No.:~~ ~~T153-45909-00056~~
~~Facility:~~ ~~Combined Cycle Combustion Turbine (Siemens)~~
~~Parameter:~~ ~~VOC emissions~~

~~Limit: The VOC emissions from the CCCT shall not exceed 29.3 tons per twelve (12) consecutive month period.~~

~~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:~~ ____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana **47849**

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

~~Part 70 Quarterly Report~~

~~Source Name: Maple Creek Energy LLC~~
~~Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana~~
~~Part 70 Permit No.: T153-45909-00056~~
~~Facility: Combined Cycle Combustion Turbine (Siemens)~~
~~Parameter: CO2e emissions~~
~~Limit: The CO2e emissions from the CCCT shall not exceed 2,040,335 tons per twelve (12) consecutive month period.~~

~~QUARTER:~~ ______________________ ~~YEAR:~~ ______________________

☐ ~~No deviation occurred in this quarter.~~
☐ ~~Deviation/s occurred in this quarter.~~

~~Deviation has been reported on:~~ ____________________

~~Submitted by:~~ ____________________

~~Title / Position:~~ ____________________

~~Signature:~~ ____________________

~~Date:~~ ____________________

~~Phone:~~ ____

Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana **47849**

*****

QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana **47849**
Part 70 Permit No.: T153-45909-00056

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.

IDEM Contact

(a) If you have any questions regarding this permit, please contact Tamera Wessel, 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) 234-8530 or (800) 451-6027, and ask for Tamera Wessel.

(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
PTE Summary

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Uncontrolled Potential to Emit (tons/yr)									
Emissions Unit	**PM**	**PM10**	**PM2.5 ***	**SO_2**	**NOx**	**VOC**	**CO**	**H_2SO_4**	**GHGs**
Emission Units Plant 1									
CCGT - Steady State and SU/SD[1]	59.57	59.57	59.57	28.47	136.12	36.14	112.69	19.27	2,065,094
CCGT - SU/SD[2]	5.91	5.91	5.91		113.73	59.64	165.71		
Auxiliary Boiler	3.15	3.15	3.15	0.59	15.55	1.45	15.55	0.059	49,247
Emergency Generator	0.17	0.17	0.17	0.006	5.32	0.35	2.89	negl.	625.26
Fire Pump	0.03	0.03	0.03	0.00	0.69	0.09	0.60	negl.	122.60
Tanks	--	--	--	--	--	0.5	--	--	--
Paved Roads (Fugitive)	*0.37*	*0.07*	*0.02*	--	--	--	--	--	--
Plant 1 Total	**63.30**	**63.00**	**62.94**	**29.07**	**157.68**	**62.03**	**184.76**	**19.33**	**2,115,089**
Plant 2 Total	60.70	60.40	60.35	28.61	140.87	37.06	116.94	19.29	2,076,487.23
Total PTE of Entire Source Including Fugitives	***124.00***	***123.40***	***123.29***	***57.67***	***298.56***	***99.09***	***301.70***	***38.62***	***4,191,576.11***

** PM2.5 listed is direct PM2.5*
***Fugitve HAP emissions are always included in the source-wide emissions*
** PM2.5 listed is direct PM2.5*
1 - Emissions include start up and shut/down operations with steady state operations
2 - Emissions represent startup/shutdown operations for 8,760 hours per year.
****The uncontrolled potential to emit of Plant 2 (Maple Creek Energy LLC) is from T153-49555-00064, pending.*

Appendix A: Emission Calculations
HAP Summary

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W. Fairbanks. Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Uncontrolled Potential to Emit (tons/yr)

Emissions Unit	1.3 Butadiene	Acenaphthene	Acenaphthylene	Acetaldehyde	Acrolein	Anthracene	Benz(a)-anthracene	Benzene	Benzo(a)-pyrene	Benzo(b)-fluoranthene	Benzo(g,h,i)-perylene	Benzo(k)-fluoranthene	Chrysene
Emission Units Plant 1													
CCGT	0.01	--	--	0.70	0.11	--	--	0.21	--	--	--	--	--
Auxiliary Boiler	--	7.31E-07	7.31E-07	--	--	9.74E-07	7.31E-07	8.52E-04	4.87E-07	7.31E-07	4.87E-07	7.31E-07	7.31E-07
Emergency Generator	--	1.67E-05	3.29E-05	8.99E-05	2.81E-05	4.39E-06	2.22E-06	2.77E-03	9.17E-07	3.96E-06	1.98E-06	7.78E-07	5.46E-06
Fire Pump	2.91E-05	1.06E-06	3.77E-06	5.71E-04	6.89E-05	1.39E-06	1.25E-06	6.95E-04	1.40E-07	7.38E-08	3.64E-07	1.15E-07	2.63E-07
	0.01	0.00	0.00	0.70	0.11	0.00	0.00	0.21	0.00	0.00	0.00	0.00	0.00
Plant 2 Total	7.54E-03	3.72E-06	7.51E-06	7.01E-01	1.12E-01	1.38E-06	8.61E-07	2.11E-01	3.23E-07	9.74E-07	5.81E-07	3.45E-07	1.31E-06
Source Total	1.51E-02	2.22E-05	4.49E-05	1.40E+00	2.24E-01	8.13E-06	5.06E-06	4.26E-01	1.87E-06	5.74E-06	3.42E-06	1.97E-06	7.76E-06

Emissions Unit	Dibenzo(a,h)-anthracene	Dichloro-benzene	Ethylbenzene	Fluoranthene	Fluorene	Formaldehyde	Hexane	Indeno(1,2,3-cd)- pyrene	Naphthalene	PAH	Phena-nathrene	Propylene	Propylene Oxide
Emission Units Plant 1													
CCGT	--	--	0.56	--	--	3.85	--	--	0.02	0.04	--	--	0.51
Auxiliary Boiler	4.87E-07	4.87E-04	--	1.22E-06	1.14E-06	0.03	7.31E-01	7.31E-07	2.48E-04	--	6.90E-06	--	--
Emergency Generator	1.23E-06	--	--	1.44E-05	4.57E-05	2.81E-04	--	1.48E-06	4.64E-04	--	1.46E-04	9.95E-03	--
Fire Pump	4.34E-07	--	--	5.67E-06	2.17E-05	8.79E-04	--	2.79E-07	6.31E-05	--	2.19E-05	1.92E-03	--
	0.00	0.00	0.56	0.00	0.00	**3.88**	0.73	2.49E-06	0.02	0.04	1.74E-04	0.012	0.51
Plant 2 Total	4.45E-07	1.11E-04	5.60E-01	4.29E-06	1.37E-05	3.86	0.17	5.18E-07	2.29E-02	3.85E-02	3.51E-05	2.37E-03	0.51
Source Total	2.60E-06	5.98E-04	1.12E+00	2.55E-05	8.23E-05	7.75	0.90	3.00E-06	4.65E-02	7.71E-02	2.09E-04	1.42E-02	1.02

Emissions Unit	Pyrene	Toluene	Xylene	Arsenic	Beryllium	Cadmium	Chromium	Cobalt	Manganese	Mercury	Nickel	Selenium	Total HAPs**	Single Highest HAP
Emission Units Plant 1														
CCGT	--	2.28	1.12	--	--	--	--	--	--	--	--	--	9.41	Formaldehyde
Auxiliary Boiler	2.03E-06	1.38E-03	--	8.12E-05	4.87E-06	4.46E-04	5.68E-04	3.41E-05	1.54E-04	1.06E-04	8.52E-04	9.74E-06	0.77	
Emergency Generator	1.32E-05	1.00E-03	6.89E-04	--	--	--	--	--	--	--	--	--	0.02	
Fire Pump	3.56E-06	3.05E-04	2.12E-04	--	--	--	--	--	--	--	--	--	4.81E-03	
	0.00	2.28	1.12	8.12E-05	4.87E-06	4.46E-04	5.68E-04	3.41E-05	1.54E-04	1.06E-04	8.52E-04	9.74E-06	**10.20**	3.88
Plant 2 Total	3.82E-06	2.28E+00	1.12	1.85E-05	1.11E-06	1.02E-04	1.30E-04	7.78E-06	3.52E-05	2.41E-05	1.95E-04	2.22E-06	9.59	3.86
Source Total	2.26E-05	4.56E+00	2.24	9.97E-05	5.98E-06	5.48E-04	6.98E-04	4.19E-05	1.89E-04	1.30E-04	1.05E-03	1.20E-05	**19.79**	7.75

** PM2.5 listed is direct PM2.5*

** PM2.5 listed is direct PM2.5*
***Fugitve HAP emissions are always included in the source-wide emissions*

Note: The gray shaded cells indicate where limits are included.
Note: Pursuant to 326 IAC 6-3-2(d), the particulate emissions from surface coating operations shall be controlled by dry particulate filters and the Permittee shall operate the control devices in accordance with the manufacturer's specifications. Compliance with this standard, in conjuction with a conservative assumption of 95% capture and control, shall limit PM, PM10, and PM2.5 emissions from the surface coating operations to the values shown.

Appendix A: Emission Calculations
Facility Data

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Data Inputs for Calculations

A: GAS TURBINES WITH HRSG & DB (EACH UNIT)	VALUE	UNIT	REFERENCE
Number of Combustion Turbines	1	1 X 1 CC	APS
Operating Hours			
Total Maximum Operating hours	8,760	hrs/yr	
Total Maximum Operating hours for CTs firing Natural Gas	8,760	hrs/yr	
Total Maximum Operating hours for DBs	NA	hrs/yr	no duct burning per APS
Fuel for CT	Natural Gas		
Fuel for DB	NA		
GT Natural Heat Input (ISO) (Case 4)	4,077	MMBtu/hr - HHV	Case 4 - T218_MCE Emissions Estimate - 7/25/22
Duct Burner Heat Input (Max)	NA	MMBtu/hr - HHV	no duct burning per APS
Total Heat Input	4,077	MMBtu/hr - HHV	Case 4 - T218_MCE Emissions Estimate - 7/25/22
Natural Gas Heat Value HHV	23,413	Btu/lbm	T218_MCE Emissions Estimate - 7/25/22
Natural Gas Heat Value LHV	21,139	Btu/lbm	T218_MCE Emissions Estimate - 7/25/22
Natural Gas Density	NA	lb/scf	
Natural Gas Sulfur Content	0.5	grains/100 dscf	T218_MCE Emissions Estimate - 7/25/22
Natural Gas Ratio HHV/LHV	1.108	unitless	Calculation, T218_MCE Emissions Estimate - 7/25/22
HRSG Stack Exit Conditions			
NOx Concentration	2	ppmvd @ 15% O_2	T218_MCE Emissions Estimate - 7/25/22
CO Concentration	2	ppmvd @ 15% O_2	T218_MCE Emissions Estimate - 7/25/22
VOC Concentration	1	ppmvd @ 15% O_2	T218_MCE Emissions Estimate - 7/25/22
Ammonia Concentration (as Slip from SCR)	5	ppmvd @ 15% O_2	T218_MCE Emissions Estimate - 7/25/22
SO_2 to SO_3 Conversion			
CTG (combustion)	NA		Conversion of SO2 to H2SO4 provided onT218_MCE Emissions Estimate - 7/25/22
SCR Catalyst	NA		
Oxid Catalyst	NA		
Total	NA		
Stack Height	185.00	ft	
Stack Diameter	23.00	ft	
SUSD Emissions - Typical Scenario [(1)]			
Number of Start-up/Shutdown Events			
Cold Start	15	events per year	Conservative Assumption based Maximum Predicted Event Occurances of each event (plus 20%). Dispatch predictions with maximum predicted event occurances were provided by MCE on 7/22/22
Warm Start	175	events per year	
Hot Start	70	events per year	
Shutdown	260	events per year	
Duration of Start-up/Shutdown Events			
Cold Start	70	minutes/event	T208a_7HA.03 RRL startup emissions memo_AP_Maple Creek-Aug 2022_Rev A
Warm Start	60	minutes/event	
Hot Start	30	minutes/event	
Shutdown	12	minutes/event	
Minimum Downtime Prior to Events			
Cold Start	72	hours/event	T208a_7HA.03 RRL startup emissions memo_AP_Maple Creek-Aug 2022_Rev A
Warm Start	8	hours/event	
Hot Start	0	hours/event	
Shutdown	0	hours/event	
SUSD EMISSIONS (EACH UNIT)			

Per GT/HRST Stack	Pounds (lbs) per Event						REFERENCE
	NOx	CO	VOC	PM10/PM2.5		Fuel (MMBTU,HHV)	
Cold Start	420.0	310.0	100.0	15.8		2,250	T208a_7HA.03 RRL startup emissions memo_AP_Maple Creek-Aug 2022_Rev A
Warm Start	260.0	230.0	85.0	13.5		1,930	
Hot Start	135.0	200.0	80.0	6.8		825	
Shutdown	40.0	175.0	60.0	2.5		182	

Appendix A: Emission Calculations
Facility Data

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number: 153-49550-00056
Reviewer: Tamera Wessel

B: EMERGENCY DIESEL GENERATOR			
Number of Emergency Diesel Generators	1		
Engine Rating	2,012	HP	
Fuel	ULSD		
Operating Hours	100	Hrs/yr	
SO2 to SO3 conversion	10%		
C: EMERGENCY FIRE WATER PUMP			
Number of Emergency Fire Water Pump	1		
Engine Rating	420	HP	
Fuel	ULSD		
Operating Hours	100	Hrs/yr	
SO2 to SO3 conversion	10%		
D: AUXILIARY BOILER			
Number of Auxiliary Boiler	1		
Maximum Heat Input	96.00	MMBtu/hr	
Fuel	natural gas		
Operating Hours	2,000	Hrs/yr	
SO2 to SO3 conversion	10%		
E: GLOBAL WARMING POTENTIAL FOR GREENHOUSE GASES (2)			
CO_2	1	CO_2e	40 CFR Part 98 Table A-1
N_2O	298	CO_2e	40 CFR Part 98 Table A-1
CH_4	25	CO_2e	40 CFR Part 98 Table A-1

(1) These parameters represent a typical SU/SD operating scenario for a baseload combined cycle facility in order to estimate potential emissions.

Appendix A: Emission Calculations
PTE Summary

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Annual Emission Rate Summary (TPY)

Pollutant	HAP?	CCGT (1)	EMGEN (2)	FWP (2)	AUX BOILER (3)	SITE TOTAL
Particulate Matter (PM_{10})	no	59.57	0.033	0.01	0.72	**60.3**
Particulate Matter ($PM_{2.5}$)	no	59.57	0.033	0.01	0.72	**60.3**
Sulfur Oxides (SO_x)	no	28.47	0.001	0.0003	0.13	**28.6**
Nitrogen Oxides (NO_x)	no	136.12	1.1	0.1	3.6	**140.9**
Carbon Monoxide (CO)	no	112.69	0.6	0.1	3.6	**116.9**
Volatile Organic Compound (VOC)	no	36.14	0.1	0.0	0.3	**36.6**
Sulfuric Acid Mist (SAM)	no	19.27	1.53E-04	3.00E-05	0.01	**19.3**
Lead	yes				4.63E-05	**4.63E-05**
Greenhouse Gas (CO_2e)	no	2,065,094.06	125.05	24.52	11,243.60	**2,076,487**
1,3-Butadiene	yes	0.01	0.00E+00	5.82E-06		**7.54E-03**
2-Methylnaphthalene	no				2.22E-06	**2.22E-06**
3-Methylchloranthrene	no				1.67E-07	**1.67E-07**
7,12-Dimethylbenz(a)anthracene	no				1.48E-06	**1.48E-06**
Acenaphthene	no		3.34E-06	2.11E-07	1.67E-07	**3.72E-06**
Acenaphthylene	no		6.59E-06	7.54E-07	1.67E-07	**7.51E-06**
Acetaldehyde	yes	0.70	1.80E-05	1.14E-04		**0.70**
Acrolein	yes	0.11	5.62E-06	1.38E-05		**0.11**
Ammonia	no	117.82				**117.82**
Anthracene	no		8.78E-07	2.79E-07	2.22E-07	**1.38E-06**
Benz(a)anthracene	no		4.44E-07	2.50E-07	1.67E-07	**8.61E-07**
Benzene	yes	0.21	5.54E-04	1.39E-04	1.95E-04	**0.21**
Benzo(a)pyrene	no		Benzene (including benzene from gasoline)	2.80E-08	1.11E-07	**1.39E-07**
Benzo(b)fluoranthene	no		7.92E-07	1.48E-08	1.67E-07	**9.74E-07**
Benzo(g,h,i)perylene	no		3.97E-07	7.28E-08	1.11E-07	**5.81E-07**
Benzo(k)fluoranthene	no		1.56E-07	2.31E-08	1.67E-07	**3.45E-07**
Chrysene	no		1.09E-06	5.26E-08	1.67E-07	**1.31E-06**
Dibenzo(a,h)anthracene	no		2.47E-07	8.68E-08	1.11E-07	**4.45E-07**
Dichlorobenzene	yes				1.11E-04	**1.11E-04**
Ethylbenzene	yes	0.56				**0.56**
Fluoranthene	no		2.88E-06	1.13E-06	2.78E-07	**4.29E-06**
Fluorene	no		9.13E-06	4.35E-06	2.59E-07	**1.37E-05**
Formaldehyde	yes	3.85	5.63E-05	1.76E-04	6.95E-03	**3.86**
Hexane	yes				1.67E-01	**0.17**
Indeno(1,2,3-cd)pyrene	no		2.95E-07	5.59E-08	1.67E-07	**5.18E-07**
Naphthalene	yes	0.02	9.28E-05	1.26E-05	5.65E-05	**0.02**
Total PAH	yes	0.04	0.000151	0.000025		**0.04**
Phenanathrene	no		2.91E-05	4.38E-06	1.58E-06	**3.51E-05**
Propylene	no		1.99E-03	3.84E-04		**0.00**
Propylene Oxide	yes	0.51				**0.51**
Pyrene	no		2.65E-06	7.12E-07	4.63E-07	**3.82E-06**
Toluene	yes	2.28	2.00E-04	6.09E-05	3.15E-04	**2.28**
Xylene (mixed isomers)	yes	1.12	1.38E-04	4.24E-05		**1.12**
Arsenic	yes				1.85E-05	**1.85E-05**
Beryllium	yes				1.11E-06	**1.11E-06**
Cadmium	yes				1.02E-04	**1.02E-04**
Chromium	yes				1.30E-04	**1.30E-04**
Cobalt	yes				7.78E-06	**7.78E-06**
Manganese	yes				3.52E-05	**3.52E-05**
Mercury	yes				2.41E-05	**2.41E-05**
Nickel	yes				1.95E-04	**1.95E-04**
Selenium	yes				2.22E-06	**2.22E-06**
Highest Individual HAP		3.85	0.0006	0.0002	0.1668	**3.86**
Total HAPs		9.41	0.00122	0.00059	0.17494	**9.59**

Notes:
(1) Criteria emissions are based on the proposed controlled emission rates as provided in "CCGT Unit Summary".
For GHG and HAPs emissions the emissions are based on 8,760 hours of operation per year.
(2) Emissions are based on 100 hours of non-emergency operations per year.
(3) Emissions are based on 2000 hours of operations per year.

Appendix A: Emission Calculations
CTG Summary

Company Name:	Maple Creek Energy LLC
Source Address:	W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM:	153-49550-00056
Permit Number SPM:	153-50217-00056
Reviewer:	Tamera Wessel

SINGLE COMBUSTION TURBINE

				280	SU_SD event hours (without downtime)			
CRITERIA POLLUTANTS				2760	SU_SD event hours (inc. downtime)			
	Steady State Operation ONLY (1)			Steady State and SU_SD Operations(3)				
Pollutant	Hourly Emissions at ISO Conditions (lbs/hr)(2)(5)(6)(7)	Maximum Hourly Emissions (lbs/hr)	Annual Emissions at ISO Conditions (ton/yr)	Emissions during SU/SD event hrs (TPY)	Emissions during Steady State Operating hrs (TPY)	Annual Emissions with SUSD and Steady State Operation (TPY)	Major Source Threshold (tpy)	SER (tpy)
Particulate Matter (PM_{10})	13.60	13.90	59.57	18.76	40.80	**59.57**	100	15
Particulate Matter ($PM_{2.5}$)	13.60	13.90	59.57	18.76	40.80	**59.57**	100	10
Sulfur Oxides (SO_x)	6.50	6.90	28.47	na	na	**28.47**	100	40
Nitrogen Oxides (NO_x)	29.10	30.90	127.46	48.81	87.31	**136.12**	100	40
Carbon Monoxide (CO)	17.70	18.80	77.53	59.59	53.10	**112.69**	100	100
Total Volatile Organic Compounds (VOC)	5.10	5.40	22.34	20.84	15.30	**36.14**	100	40
Sulfuric acid mist (SAM)	4.40	4.70	19.27	NA	NA	**19.27**	100	7

GHG

	Steady State Operation ONLY			Steady State and SU_SD Operations				
Pollutant	Hourly Emissions at ISO Conditions (lbs/hr)(2)	Maximum Hourly Emissions (lbs/hr)	Annual Emissions at ISO Conditions (ton/yr)	Emissions during SU/SD event hrs (TPY)	Emissions during Steady State Operating hrs (TPY)	Annual Emissions with SUSD and Steady State Operation (TPY)(4)	Major Source Threshold (tpy)	SER (tpy)
CO_2	471,000	501,000	2,062,980	NA	NA	2,062,980		
N_2O	0.88	0.94	3.86	NA	NA	4		
CH_4	8.81	9.37	38.58	NA	NA	39		
CO_2e	471,483	501,513	2,065,094	NA	NA	2,065,094	NA	75000

B: HAP/TAP

	Steady State Operation ONLY			Steady State and SU_SD Operations				
Pollutant	Hourly Emissions at ISO Conditions (lbs/hr)(2)	Maximum Hourly Emissions (lbs/hr)	Annual Emissions at ISO Conditions (ton/yr)	Emissions during SU/SD event hrs (TPY)	Emissions during Steady State Operating hrs (TPY)	Annual Emissions with SUSD and Steady State Operation (TPY)(4)	Major Source Threshold (tpy)	SER (tpy)
1,3 Butadiene	0.002	0.002	0.01	NA	NA	0.01		
Acetaldehyde	0.160	0.170	0.70	NA	NA	0.70		
Acrolein	0.026	0.027	0.11	NA	NA	0.11		
Ammonia	26.90	28.600	117.82	NA	NA	117.82		
Benzene	0.048	0.051	0.21	NA	NA	0.21		
Ethylbenzene	0.128	0.136	0.56	NA	NA	0.56		
Formaldehyde	0.880	0.936	3.85	NA	NA	3.85		
Naphthalene	0.005	0.006	0.02	NA	NA	0.02		
PAH	0.009	0.009	0.04	NA	NA	0.04		
Propylene Oxide	0.116	0.123	0.51	NA	NA	0.51		
Toluene	0.520	0.553	2.28	NA	NA	2.28		
Xylene (Total)	0.256	0.272	1.12	NA	NA	1.12		
Maximum Indvidual HAP						3.85	10	NA
Total HAPs						9.41	25	NA

Notes:
(1) CTG/HRSG Emissions provided by GE "1592244 AP - Maple Creek Plant Emissions Estimate Rev -.xlsx"
(2) ISO Conditions are considered to be Case 4 (59°F/EC on)
(3) Refer to "GE SU SD" tab for calculations
(4) Steady State emissions are considered worst-case as emissions for these pollutants are based on fuel consumption.
(5) Assumes 80% control of NOX from selective catalytic reduction system to estimate uncontrolled emission factor. Actual control efficiency will vary based on ambient air and load conditions.
(6) Assumes 80% control of CO from oxidation catalyst to estimate uncontrolled emission factor. Actual control efficiency will vary based on ambient air and load conditions.
(7) Assumes 25% control of VOC from oxidation catalyst to estimate uncontrolled emission factor. Actual control efficiency will vary based on ambient air and load conditions.

Appendix A: Emission Calculations
CGT Data

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Combined Cycle Systems Emissions Estimates: AP - Maple Creek

Operating Point		3	4	5	6	8	9	10	11	12	13	14	15	16	
Case Description		-20°F, Gas fuel, 1 GT @ 100% load	-20°F, Gas fuel, 1 GT @ 27.8% load	16°F, Gas fuel, 1 GT @ 100% load	16°F, Gas fuel, 1 GT @ 19.2% load	59°F, Gas fuel, 1 GT @ 100% load, EC on	59°F, Gas fuel, 1 GT @ 97.9% load	59°F, Gas fuel, 1 GT @ 19.6% load	87°F, Gas fuel, 1 GT @ 100% load, EC on	87°F, Gas fuel, 1 GT @ 93.9% load	87°F, Gas fuel, 1 GT @ 20.2% load	105°F, Gas fuel, 1 GT @ 100% load, EC on	105°F, Gas fuel, 1 GT @ 89.7% load	105°F, Gas fuel, 1 GT @ 21.7% load	Maximum
Ambient Conditions															
Ambient Temperature	°F	-20.0	-20.0	16.0	16.0	59.0	59.0	59.0	87.0	87.0	87.0	105.0	105.0	105.0	
Ambient Pressure	psia	14.4	14.4	14.411	14.411	14.4	14.4	14.4	14.411	14.411	14.411	14.4	14.4	14.4	
Ambient Relative Humidity	%	86.0	86.0	76	76	60.0	60.0	60.0	49	49	49	49.0	49.0	49.0	
Gas Turbine															
GT Fuel Type		Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	Gas	
Number of Gas Turbines operating per Block		1.0	1.0	1	1	1.0	1.0	1.0	1	1	1	1.0	1.0	1.0	
GT load fraction	-	1.0	0.3	1	0.192	1.0	1.0	0.2	1	0.939	0.202	1.0	0.9	0.2	
Evap Cooler status		off	off	off	off	On	off	off	On	off	off	On	off	off	
Gas turbine water injection flow rate	klb/h	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Abatement Status															
CO Catalyst Operating status		Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	
SCR Operating status		Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	
GT Fuel															
Gas Turbine fuel LHV	Btu/lb	21139	21139	21139	21139	21139	21139	21139	21139	21139	21139	21139	21139	21139	
Gas Turbine fuel HHV	Btu/lb	23413	23413	23413	23413	23413	23413	23413	23413	23413	23413	23413	23413	23413	
Gas Turbine gas fuel molecular weight	lb/lbmole	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	
Gas Turbine sulfur ppm (by mass)	ppm	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	
Duct Burner															
Duct Burner fuel LHV	Btu/lb	21139	21139	21139	21139	21139	21139	21139	21139	21139	21139	21139	21139	21139	
Duct Burner fuel HHV	Btu/lb	23413	23413	23413	23413	23413	23413	23413	23413	23413	23413	23413	23413	23413	
Duct Burner fuel molecular weight	lb/lbmole	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	17.11	
Duct Burner fuel sulfur content (by mass)	ppm	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	
Duct Burner status		Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	
Duct Burner gas fuel flow	klb/h	0	0	0.0	0.0	0	0	0	0.0	0.0	0.0	0	0	0	
Duct Burner load fraction	%	0	0	0.0	0.0	0	0	0	0.0	0.0	0.0	0	0	0	
Heat Consumption for permitting (per unit)															
GT Heat Cons (HHV), with permitting margin	MMBtu/h	4252.4	1777.7	4188.8	1455.9	4077.3	3998.7	1440.8	3989.2	3776.7	1407.1	3765.9	3438.2	1394.4	
DB Heat Cons (HHV)	MMBtu/h	0	0	0.0	0.0	0	0	0	0.0	0.0	0.0	0	0	0	
HRSG Exit Exhaust gas (per unit)															
Stack N2 mole fraction	-	0.7452	0.7549	0.7443	0.7522	0.7362	0.7382	0.7469	0.7266	0.7303	0.7384	0.7148	0.7191	0.7263	
Stack O2 mole fraction	-	0.1079	0.1356	0.109	0.1317	0.106	0.107	0.1322	0.1049	0.1065	0.1301	0.1036	0.105	0.1265	
Stack AR mole fraction	-	0.008873	0.008988	0.008863	0.008957	0.008766	0.008789	0.008893	0.008652	0.008696	0.008793	0.008511	0.008562	0.008648	
Stack H2O mole fraction	-	0.09084	0.06611	0.09129	0.07103	0.1021	0.09934	0.077	0.1136	0.1085	0.08767	0.1278	0.1222	0.1034	
Stack CO2 mole fraction	-	0.04715	0.03434	0.04647	0.03598	0.04685	0.04664	0.03501	0.04613	0.04579	0.03488	0.04517	0.04502	0.03508	
Stack Molecular Weight	lb/lbmole	28.39	28.55	28.38	28.51	28.27	28.3	28.43	28.13	28.19	28.32	27.97	28.03	28.15	
Stack Temperature	°F	198.7	199.1	198.6	178.6	194.9	194.3	179.1	207.5	203.8	178.7	220.2	213	188.8	
Stack Mass flow, including Permitting Margin, per stack	lb/h	6850200	3962300	6843600	3092200	6579800	6489200	3136600	6508300	6218400	3062000	6238000	5725900	2998300	
Margined exhaust vol flow (incl. permitting margin)	Mft3/h	118.28	68.088	118.2	51.558	113.47	111.69	52.472	114.93	109	51.403	112.91	102.34	51.444	
HRSG Exit Emissions (per unit)															
NOx Volume fraction, dry, at 15 % O2	ppm	2	2	2	2	2	2	2	2	2	2	2	2	2	
NOx mass flow rate (as NO2)	lb/h	30.9	12.9	30.4	10.6	29.6	29.1	10.5	29.0	27.4	10.2	27.4	25	10.1	30.9
CO Volume fraction, dry, at 15 % O2	ppm	2	2	2	2	2	2	2	2	2	2	2	2	2	
CO mass flow rate	lb/h	18.8	7.8	18.5	6.4	18	17.7	6.4	17.7	16.7	6.2	16.7	15.2	6.2	18.8
VOC Volume fraction, dry, at 15 % O2	ppm	1	1	1	1	1	1	1	1	1	1	1	1	1	
VOC mass flow rate (as methane)	lb/h	5.4	2.2	5.3	1.8	5.2	5.1	1.8	5.1	4.8	1.8	4.8	4.4	1.8	5.4
NH3 Volume fraction, dry, at 15 % O2	ppm	5	5	5	5	5	5	5	5	5	5	5	5	5	
NH3 mass flow rate	lb/h	28.6	11.9	28.2	9.8	27.4	26.9	9.7	26.8	25.4	9.4	25.3	23.1	9.4	28.6
SOx mass flow rate (as SO2)	lb/h	6.9	2.9	6.8	2.4	6.6	6.5	2.3	6.5	6.2	2.3	6.1	5.6	2.3	6.9
Total Particulates	lb/h	13.9	8.68	13.8	7.7	13.7	13.6	7.86	13.6	13.3	7.9	13.3	12.9	8.03	13.9
Sulfur Mist as H2SO4	lb/h	4.7	2.0	4.6	1.6	4.5	4.4	1.6	4.4	4.2	1.5	4.1	3.8	1.5	4.7
Stack CO2 mass flow rate, including Permitting margin	lb/h	501000	210000	493000	172000	480000	471000	170000	470000	445000	166000	443000	405000	164000	501000.0
Total Particulates	lb/MMBtu	0.0033	0.0049	0.0033	0.0053	0.0034	0.0034	0.0055	0.0034	0.0035	0.0056	0.0035	0.0038	0.0058	0.00576
Sulfur Mist as H2SO4	lb/MMBtu	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.00113
NOx mass flow rate (as NO2)	lb/MMBtu	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0072	0.0073	0.0073	0.0072	0.00729
CO mass flow rate	lb/MMBtu	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.00445
VOC mass flow rate (as methane)	lb/MMBtu	0.0013	0.0012	0.0013	0.0012	0.0013	0.0013	0.0012	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.00129
SOx mass flow rate (as SO2)	lb/MMBtu	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.0016	0.00165

HAP and Other GHGs (lb/hr)

		3	4	5	6	8	9	10	11	12	13	14	15	16	Maximum lb/hr
LOAD LEVEL		-20°F, Gas fuel, 1 GT @ 100% load	-20°F, Gas fuel, 1 GT @ 27.8% load	16°F, Gas fuel, 1 GT @ 100% load	16°F, Gas fuel, 1 GT @ 19.2% load	59°F, Gas fuel, 1 GT @ 100% load, EC on	59°F, Gas fuel, 1 GT @ 97.9% load	59°F, Gas fuel, 1 GT @ 19.6% load	GT @ 100% load, EC on	87°F, Gas fuel, 1 GT @ 93.9% load	87°F, Gas fuel, 1 GT @ 20.2% load	GT @ 100% load, EC on	105°F, Gas fuel, 1 GT @ 89.7% load	105°F, Gas fuel, 1 GT @ 21.7% load	
AMBIENT DRY BULB TEMPERATURE, °F		-20	-20	16	16	59	59	59	87	87	87	105	105	105	
methane (CH4)	2.20E-03	9.37E+00	3.92E+00	9.23E+00	3.21E+00	8.98E+00	8.81E+00	3.17E+00	8.79E+00	8.32E+00	3.10E+00	8.29E+00	7.57E+00	3.07E+00	9.37E+00
nitrous oxide (N2O)	2.20E-04	9.37E-01	3.92E-01	9.23E-01	3.21E-01	8.98E-01	8.81E-01	3.17E-01	8.79E-01	8.32E-01	3.10E-01	8.29E-01	7.57E-01	3.07E-01	9.37E-01
1,3 Butadiene	4.30E-07	1.83E-03	7.64E-04	1.80E-03	6.26E-04	1.75E-03	1.72E-03	6.20E-04	1.72E-03	1.62E-03	6.05E-04	1.62E-03	1.48E-03	6.00E-04	1.83E-03
Acetaldehyde	4.00E-05	1.70E-01	7.11E-02	1.68E-01	5.82E-02	1.63E-01	1.60E-01	5.76E-02	1.60E-01	1.51E-01	5.63E-02	1.51E-01	1.38E-01	5.58E-02	1.70E-01
Acrolein	6.40E-06	2.72E-02	1.14E-02	2.68E-02	9.32E-03	2.61E-02	2.56E-02	9.22E-03	2.55E-02	2.42E-02	9.01E-03	2.41E-02	2.20E-02	8.92E-03	2.72E-02
Benzene	1.20E-05	5.10E-02	2.13E-02	5.03E-02	1.75E-02	4.89E-02	4.80E-02	1.73E-02	4.79E-02	4.53E-02	1.69E-02	4.52E-02	4.13E-02	1.67E-02	5.10E-02
Ethylbenzene	3.20E-05	1.36E-01	5.69E-02	1.34E-01	4.66E-02	1.30E-01	1.28E-01	4.61E-02	1.28E-01	1.21E-01	4.50E-02	1.21E-01	1.10E-01	4.46E-02	1.36E-01
Formaldehyde (MACT Limit for CTG)	2.20E-04	9.36E-01	3.91E-01	9.22E-01	3.20E-01	8.97E-01	8.80E-01	3.17E-01	8.78E-01	8.31E-01	3.10E-01	8.28E-01	7.56E-01	3.07E-01	9.36E-01
Naphthalene	1.30E-06	5.53E-03	2.31E-03	5.45E-03	1.89E-03	5.30E-03	5.20E-03	1.87E-03	5.19E-03	4.91E-03	1.83E-03	4.90E-03	4.47E-03	1.81E-03	5.53E-03
PAH	2.20E-06	9.36E-03	3.91E-03	9.22E-03	3.20E-03	8.97E-03	8.80E-03	3.17E-03	8.78E-03	8.31E-03	3.10E-03	8.28E-03	7.56E-03	3.07E-03	9.36E-03
Propylene Oxide	2.90E-05	1.23E-01	5.16E-02	1.21E-01	4.22E-02	1.18E-01	1.16E-01	4.18E-02	1.16E-01	1.10E-01	4.08E-02	1.09E-01	9.97E-02	4.04E-02	1.23E-01
Toluene	1.30E-04	5.53E-01	2.31E-01	5.45E-01	1.89E-01	5.30E-01	5.20E-01	1.87E-01	5.19E-01	4.91E-01	1.83E-01	4.90E-01	4.47E-01	1.81E-01	5.53E-01
Xylene (Total)	6.40E-05	2.72E-01	1.14E-01	2.68E-01	9.32E-02	2.61E-01	2.56E-01	9.22E-02	2.55E-01	2.42E-01	9.01E-02	2.41E-01	2.20E-01	8.92E-02	2.72E-01

Appendix A: Emission Calculations
CGT Data

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Project information

Advance Power/ Maple Creek
IN
A. Kos
22-Jul-2022
1 block(s) 1x1 7HA.03_NG only SS A650-40LSB ACC
Design Point HRSG Steam conditions: 2338#/1085F/1085F
Duct firing: None
ITD or (TTD + Trise + Twb aprch): 47.6F
Ambient pressure: 14.4107 psia

SUMMARY TABLE

Case / **Description**		HB_NG_1 1x GT @100%; Evap Cooler OFF, Duct Burner OFF	HB_NG_2 1x GT @75%; Evap Cooler OFF, Duct Burner OFF	HB_NG_3 1x GT @62%; Evap Cooler OFF, Duct Burner OFF	HB_NG_4 1x GT @100%; Evap Cooler ON, Duct Burner OFF	HB_NG_5 1x GT @100%; Evap Cooler OFF, Duct Burner OFF	HB_NG_6 1x GT @75%; Evap Cooler OFF, Duct Burner OFF	HB_NG_7 1x GT @29%; Evap Cooler OFF, Duct Burner OFF	HB_NG_8 1x GT @100%; Evap Cooler ON, Duct Burner OFF	HB_NG_9 1x GT @100%; Evap Cooler OFF, Duct Burner OFF	HB_NG_10 1x GT @75%; Evap Cooler OFF, Duct Burner OFF	HB_NG_11 1x GT @36%; Evap Cooler OFF, Duct Burner OFF
Ambient temperature/ Relative humidity		-15°F/86%RH	-15°F/86%RH	-15°F/86%RH	59°F/60%RH	59°F/60%RH	59°F/60%RH	59°F/60%RH	105°F/49%RH	105°F/49%RH	105°F/49%RH	105°F/49%RH
Gross output	kW	629,948	493,467	421,421	634,067	630,459	488,112	237,833	564,011	513,755	398,976	222,837
Gross heat rate- LHV	Btu/kWh	5,579	5,714	5,852	5,447	5,440	5,550	6,381	5,706	5,721	5,891	6,665
Gross heat rate-HHV	Btu/kWh	6,183	6,332	6,486	6,036	6,029	6,152	7,073	6,324	6,341	6,529	7,387
Estimated plant aux load	kW	10,688	9,156	8,504	12,556	12,527	10,912	7,961	11,840	11,258	10,002	8,536
Plant aux load (% of Gross output)	-	1.70%	1.86%	2.02%	1.98%	1.99%	2.24%	3.35%	2.10%	2.19%	2.51%	3.83%
Net plant output	**kW**	**619,261**	**484,312**	**412,917**	**621,511**	**617,931**	**477,201**	**229,872**	**552,172**	**502,497**	**388,974**	**214,301**
Net plant heat rate- LHV	Btu/kWh	5,675	5,822	5,972	5,557	5,550	5,677	6,602	5,829	5,849	6,042	6,930
Net plant efficiency- LHV	%	60.13%	58.61%	57.13%	61.41%	61.47%	60.10%	51.68%	58.54%	58.33%	56.47%	49.23%
Net plant heat rate- HHV	Btu/kWh	6,289	6,452	6,619	6,158	6,152	6,292	7,318	6,460	6,483	6,696	7,681
Net plant efficiency- HHV	%	54.25%	52.88%	51.55%	55.41%	55.47%	54.23%	46.63%	52.82%	52.63%	50.95%	44.42%
GT Load		100%	75%	62%	100%	100%	75%	29%	100%	100%	75%	36%
Duct Burner Heat Consumption (all HRSGs)- HHV	MBtu/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HP Throttle P	psia	2301	1953	1767	2379	2376	1940	1309	2317	2169	1802	1315
ST exhaust pressure	inHg	2.713	2.000	2.000	2.713	2.713	2.100	2.000	8.816	8.240	6.841	5.275
LP Annulus Velocity	ft/s	760	861	787	779	779	820	600	265	266	266	252
DB exit temp	°F	1100	1118	1116	1114	1114	1118	1109	1115	1123	1117	1110

Fuel properties (all GTs)		HB_NG_1	HB_NG_2	HB_NG_3	HB_NG_4	HB_NG_5	HB_NG_6	HB_NG_7	HB_NG_8	HB_NG_9	HB_NG_10	HB_NG_11
HHV/LHV ratio	-	1.108	1.108	1.108	1.108	1.108	1.108	1.108	1.108	1.108	1.108	1.108
LHV (mass)	Btu/lb	20,515.9	20,515.9	20,515.9	20,515.9	20,515.9	20,515.9	20,515.9	20,515.9	20,515.9	20,515.9	20,515.9
HHV (mass)	Btu/lb	22,737.8	22,737.8	22,737.8	22,737.8	22,737.8	22,737.8	22,737.8	22,737.8	22,737.8	22,737.8	22,737.8
LHV (vol)	Btu/ft³	924.8	924.8	924.8	924.8	924.8	924.8	924.8	924.8	924.8	924.8	924.8
HHV (vol)	Btu/ft³	1,025.0	1,025.0	1,025.0	1,025.0	1,025.0	1,025.0	1,025.0	1,025.0	1,025.0	1,025.0	1,025.0

ESTIMATED AUX LOADS		HB_NG_1	HB_NG_2	HB_NG_3	HB_NG_4	HB_NG_5	HB_NG_6	HB_NG_7	HB_NG_8	HB_NG_9	HB_NG_10	HB_NG_11
GE Aux	kW	1577	1596	1593	1587	1581	1596	1588	1570	1570	1570	1570
Rest of plat BOP aux												
Main step-up xformer	kW	2192	2192	2192	2192	2192	2192	2192	2192	2192	2192	2192
Lighting/ HVAC/Other	kW	1890	1480	1264	1902	1891	1464	713	1692	1541	1197	669
Vacuum pumps	kW	78	67	61	80	80	66	45	68	64	53	39
Condensate pump	kW	349	255	212	367	366	252	131	350	310	219	131
Boiler feed pump	kW	2960	2113	1734	3158	3149	2086	969	2980	2599	1798	975
Aux cooling load	kW	0	0	0	0	0	0	0	0	0	0	0
Water treatment &service air compressors	kW	150	150	150	150	150	150	150	150	150	150	150
ACC or WCT fans	kW	1419	1242	1242	3031	3031	3031	2122	2755	2755	2755	2755
WCT circ water pump	kW	0	0	0	0	0	0	0	0	0	0	0
Aux xformers and misc elec system losses	kW	73	60	55	88	88	75	51	82	78	67	56
Rest of plat BOP aux total	kW	9111	7559	6910	10969	10946	9316	6373	10270	9688	8432	6966
Total estimated plant aux load	kW	10688	9156	8504	12556	12527	10912	7961	11840	11258	10002	8536

Preliminary Performance Estimates for Reference Only, NOT for guarantee.

Appendix A: Emission Calculations
Startup/Shutdown Emissions

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Mode	Events/year	Time (min) per event	Min Downtime before Event (hr)	Total Time per event (hr)	Total Pounds Per Event NOx	CO	VOC	PM		Fuel Use
StartUp - Cold:	15	70	72	73.17	420	310	100	15.8		2,250
StartUp - Warm:	175	60	8	9.00	260	230	85	13.5		1930
StartUp - Hot:	70	30	0	0.50	135	200	80	6.8		825
Shutdown:	260	12	0	0.20	40	175	60	2.5		182

Maximum Hourly Emissions (for modeling)

		Total Time per event (min) (no downtime)	Total Event Time per Year (hr) (no downtime)	SU/SD Lb per min (not including downtime) NOx	CO	VOC	PM		Max Steady State lb per min NOx	CO	VOC	PM		Max Hourly Emissions During SU/SD Event NOx	CO	VOC	PM	
StartUp - Cold:	15	70.00	17.5	6.0	4.4	1.4	0.2		0.5	0.3	0.1	0.2		360.0	265.7	85.7	13.5	
StartUp - Warm:	175	60.00	175.0	4.3	3.8	1.4	0.2		0.5	0.3	0.1	0.2		260.0	230.0	85.0	13.5	
StartUp - Hot:	70	30.00	35.0	4.5	6.7	2.7	0.2		0.5	0.3	0.1	0.2		150.5	209.4	82.7	13.8	
Shutdown:	260	12.00	52.0	3.3	14.6	5.0	0.2		0.5	0.3	0.1	0.2		64.7	190.0	64.3	13.6	
TOTAL			279.5															

Annual Average Emissions

SU/SD hrs per year 279.5 w/o downtime
SU/SD hrs per year 2759.5 with downtime

	Events/year	Total Time per event (hr) (no downtime)	Annual Hours for SU/SD Events	SU/SD lb per yr (for SU/SD Hours including downtime) NOx	CO	VOC	PM		Normal Operation lb per year (for SU/SD Hours including downtime) NOx	CO	VOC	PM		Worst Case Annual Emissions lb per yr (During SU_SD Event Hours including downtime) NOx	CO	VOC	PM	SO2
StartUp - Cold:	15	1.17	1097.5	6300	4650	1500	237		31937	19426	5597	14926		31937	19426	5597	14926	0
StartUp - Warm:	175	1.00	1575.0	45500	40250	14875	2363		45833	27878	8033	21420		45833	40250	14875	21420	0
StartUp - Hot:	70	0.50	35.0	9450	14000	5600	476		1019	620	179	476		9450	14000	5600	476	0
Shutdown:	260	0.20	52.0	10400	45500	15600	650		1513	920	265	707		10400	45500	15600	707	0
TOTAL SU_SD EVENT HRS:		279.5	2759.5															
Annual Emissions During SU_SD Event Hours (inc. downtime) (tpy)			2759.5											48.8	59.6	20.8	18.8	0.0
Annual Emissions During Steady State Operation			6000.5											87.3	53.1	15.3	40.8	19.5
TOTAL			8760.0											**136.1**	**112.7**	**36.1**	**59.6**	**19.5**

A For pollutants that are self-correcting hourly emissions are during normal operation, for non self correcting pollutants, emissions are during SU/SD event.
B Incorporates SU/SD emissions for those pollutants that are not self-correcting as indicated with orange shading.
C Max Hourly Emissions During SU/SD event incorporates assumes steady state operation for the remainder of the hour.

Emissions for Modeling (lb/hr)

	Events/year	Total Time per event (min) (no downtime)	Max 1-hour NOx	CO	PM	8-hr NOx	CO	PM	24-hr NOx	CO	PM	Annual Average NOx	CO	PM
StartUp - Cold:	15	70	360.0	na	na	na	76.2	na	na	na	13.9	38.1	na	13.9
StartUp - Warm:	175	60	260.0	na	na	na	66.6	na	na	na	13.8	38.1	na	13.9
StartUp - Hot:	70	30	150.5	na	na	na	154.5	na	na	na	13.7	38.1	na	13.9
Shutdown:	260	12	64.7	na	na	na	154.5	na	na	na	13.9	38.1	na	13.9

Operating Scenarios (min of operation)

8-hr scenarios (480 min)	cold # of events	cold total minutes	warm # of events	warm total minutes	hot # of events	hot total minutes	shutdown # of events	shutdown total minutes	SS (minutes)	Minutes in Avg Period
StartUp - Cold Scenario (min)	1	70		0		0	1	12	398	480
StartUp - Warm Scenario		0	1	60		0	1	12	408	480
StartUp - Hot Scenario[a]		0		0	3	90	3	36	354	480
Shutdown:		0		0	3	90	3	36	354	480

24-hr scenarios (1440 min)	cold # of events	cold total minutes	warm # of events	warm total minutes	hot # of events	hot total minutes	shutdown # of events	shutdown total minutes	SS (minutes)	Minutes in Avg Period	Exhaust Flow during event (acfm)	steady state (acfm)	Time Wghtd Average (acfm)
StartUp - Cold Scenario (min)	1	70		0		0	1	12	1358	1440	874,533	1,891,167	1,833,275
StartUp - Warm Scenario		0	3	180		0	3	36	1224	1440	874,533	1,891,167	1,738,672
StartUp - Hot Scenario[a]		0		0	9	270	9	108	1062	1440	874,533	1,891,167	1,624,300
Shutdown:		0		0		0	0	0	1440	1440	874,533	1,891,167	1,891,167

Annual Average scenarios	cold # of events	cold total minutes	warm # of events	warm total minutes	hot # of events	hot total minutes	shutdown # of events	shutdown total minutes	SS (minutes)	Minutes in Avg Period	Exhaust Flow during event (acfm)	steady state (acfm)	Time Wghtd Average (acfm)
SU/SD Events	15	1050	175	10500	70	2100	260	3120	508830	525600	874,533	1,891,167	1,858,730

a Assumed that CTG would run SS for at least 2 hr after each hot start.

Appendix A: Emission Calculations
Auxiliary Boiler

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Auxiliary Boiler Emission Calculations

Emission calculations shown below depict emissions from an auxiliary boiler with a maximum rating of 96 MMBTU/hr. Emission estimates are based on a maximum annual operating time of 2000 hours per year

Pollutant	Annual Operation (hrs/yr)	Limited Annual Operation (hrs/yr)	Boiler Size (MMBTU/hr)	Emission Factor (1)	Emission Factor Units(1)	Emissions (Potential to Emit) Average (2) (lbs/hr)	Maximum (3) (lbs/hr)	Annual (tons/yr)	Limited Annual (4) (tons/yr)
Particulate Matter (PM_{10})	8760	2,000	96.00	0.7200	lb/hr	0.720	0.720	3.15	0.720
Particulate Matter ($PM_{2.5}$)	8760	2,000	96.00	0.7200	lb/hr	0.720	0.720	3.15	0.720
Sulfur Oxides (SO_x)	8760	2,000	96.00	0.1345	lb/hr	0.134	0.134	0.59	0.134
Nitrogen Oxides (NO_x)(5)	8760	2,000	96.00	3.5500	lb/hr	3.550	3.550	15.55	3.550
Carbon Monoxide (CO)	8760	2,000	96.00	3.5500	lb/hr	3.550	3.550	15.55	3.550
Total Volatile Organic Compounds (VOC)(5)	8760	2,000	96.00	0.3300	lb/hr	0.330	0.330	1.45	0.330
Sulfuric Acid Mist (as H_2SO_4)	8760	2,000	96.00	0.0001	lb/MMBTU	0.013	0.013	0.06	0.013
Lead	8760	2,000	96.00	4.83E-07	lb/MMBTU	0.000046	0.000046	0.00	0.000046
Carbon Dioxide (CO_2)	8760	2,000	96.00	1.17E+02	lb/MMBTU	11232.000	11232.000	49196.16	11232.00
Methane (CH_4)	8760	2,000	96.00	2.20E-03	lb/MMBTU	0.212	0.212	0.93	2.1E-01
Nitrous Oxide (N_2O)	8760	2,000	96.00	2.20E-04	lb/MMBTU	0.021	0.021	0.09	2.1E-02
CO_2e	8760	2,000	96.00	--	--	11243.60	11243.60	49246.96	11243.60
2-Methylnaphthalene	8760	2,000	96.00	2.32E-08	lb/MMBTU	0.0000022	0.0000022	9.74E-06	2.22E-06
3-Methylchloranthrene	8760	2,000	96.00	1.74E-09	lb/MMBTU	0.0000002	0.0000002	7.31E-07	1.67E-07
7,12-Dimethylbenz(a)anthracene	8760	2,000	96.00	1.54E-08	lb/MMBTU	0.0000015	0.0000015	6.49E-06	1.48E-06
Acenaphthene	8760	2,000	96.00	1.74E-09	lb/MMBTU	0.0000002	0.0000002	7.31E-07	1.67E-07
Acenaphthylene	8760	2,000	96.00	1.74E-09	lb/MMBTU	0.0000002	0.0000002	7.31E-07	1.67E-07
Anthracene	8760	2,000	96.00	2.32E-09	lb/MMBTU	0.0000002	0.0000002	9.74E-07	2.22E-07
Benz(a)anthracene	8760	2,000	96.00	1.74E-09	lb/MMBTU	0.0000002	0.0000002	7.31E-07	1.67E-07
Benzene	8760	2,000	96.00	2.03E-06	lb/MMBTU	0.0001946	0.0001946	8.52E-04	1.95E-04
Benzo(a)pyrene	8760	2,000	96.00	1.16E-09	lb/MMBTU	0.0000001	0.0000001	4.87E-07	1.11E-07
Benzo(b)fluoranthene	8760	2,000	96.00	1.74E-09	lb/MMBTU	0.0000002	0.0000002	7.31E-07	1.67E-07
Benzo(g,h,i)perylene	8760	2,000	96.00	1.16E-09	lb/MMBTU	0.0000001	0.0000001	4.87E-07	1.11E-07
Benzo(k)fluoranthene	8760	2,000	96.00	1.74E-09	lb/MMBTU	0.0000002	0.0000002	7.31E-07	1.67E-07
Chrysene	8760	2,000	96.00	1.74E-09	lb/MMBTU	0.0000002	0.0000002	7.31E-07	1.67E-07
Dibenzo(a,h)anthracene	8760	2,000	96.00	1.16E-09	lb/MMBTU	0.0000001	0.0000001	4.87E-07	1.11E-07
Dichlorobenzene	8760	2,000	96.00	1.16E-06	lb/MMBTU	0.0001112	0.0001112	4.87E-04	1.11E-04
Fluoranthene	8760	2,000	96.00	2.90E-09	lb/MMBTU	0.0000003	0.0000003	1.22E-06	2.78E-07
Fluorene	8760	2,000	96.00	2.70E-09	lb/MMBTU	0.0000003	0.0000003	1.14E-06	2.59E-07
Formaldehyde	8760	2,000	96.00	7.24E-05	lb/MMBTU	0.0069498	0.0069498	3.04E-02	6.95E-03
Hexane	8760	2,000	96.00	1.74E-03	lb/MMBTU	0.1667954	0.1667954	7.31E-01	1.67E-01
Indeno(1,2,3-cd)pyrene	8760	2,000	96.00	1.74E-09	lb/MMBTU	0.0000002	0.0000002	7.31E-07	1.67E-07
Naphthalene	8760	2,000	96.00	5.89E-07	lb/MMBTU	0.0000565	0.0000565	2.48E-04	5.65E-05
Phenanathrene	8760	2,000	96.00	1.64E-08	lb/MMBTU	0.0000016	0.0000016	6.90E-06	1.58E-06
Pyrene	8760	2,000	96.00	4.83E-09	lb/MMBTU	0.0000005	0.0000005	2.03E-06	4.63E-07
Toluene	8760	2,000	96.00	3.28E-06	lb/MMBTU	0.0003151	0.0003151	1.38E-03	3.15E-04
Arsenic	8760	2,000	96.00	1.93E-07	lb/MMBTU	0.0000185	0.0000185	8.12E-05	1.85E-05
Beryllium	8760	2,000	96.00	1.16E-08	lb/MMBTU	0.000001	0.000001	4.87E-06	1.11E-06
Cadmium	8760	2,000	96.00	1.06E-06	lb/MMBTU	0.0001019	0.0001019	4.46E-04	1.02E-04
Chromium	8760	2,000	96.00	1.35E-06	lb/MMBTU	0.0001297	0.0001297	5.68E-04	1.30E-04
Cobalt	8760	2,000	96.00	8.11E-08	lb/MMBTU	0.0000078	0.0000078	3.41E-05	7.78E-06
Manganese	8760	2,000	96.00	3.67E-07	lb/MMBTU	0.0000352	0.0000352	1.54E-04	3.52E-05
Mercury	8760	2,000	96.00	2.51E-07	lb/MMBTU	0.0000241	0.0000241	1.06E-04	2.41E-05
Nickel	8760	2,000	96.00	2.03E-06	lb/MMBTU	0.0001946	0.0001946	8.52E-04	1.95E-04
Selenium	8760	2,000	96.00	2.32E-08	lb/MMBTU	0.0000022	0.0000022	9.74E-06	2.22E-06
Total HAP								**0.77**	**0.17**

vendor data	0.7200 lb/hr	=	0.0075 lb/MMBTU
	0.7200 lb/hr	=	0.0075 lb/MMBTU
Based on 0.5 gr S /100 scf	0.1345 lb/hr	=	0.0014 lb/MMBTU
vendor data	3.5500 lb/hr	=	0.0370 lb/MMBTU
	3.5500 lb/hr	=	0.0370 lb/MMBTU
	0.3300 lb/hr	=	0.0034 lb/MMBTU
SO2 to SO3 Conversion	0.14 lb/MMscf	=	0.00014 lb/MMBTU
From AP-42 (7/98); Tables 1.4-2	5.00E-04 lb/MMscf		4.83E-07 lb/MMBTU
40 CFR 98 Table C-2	5.31E+01 kg/MMBtu		117.00 lb/MMBTU
	1.00E-03 kg/MMBtu	=	2.20E-03 lb/MMBTU
	1.00E-04 kg/MMBtu	=	2.20E-04 lb/MMBTU
NA	NA		NA
From AP-42 (7/98); Tables 1.4-3	2.40E-05 lb/MMscf	=	2.32E-08 lb/MMBTU
	1.80E-06 lb/MMscf	=	1.74E-09 lb/MMBTU
	1.60E-05 lb/MMscf	=	1.54E-08 lb/MMBTU
	1.80E-06 lb/MMscf	=	1.74E-09 lb/MMBTU
	1.80E-06 lb/MMscf	=	1.74E-09 lb/MMBTU
	2.40E-06 lb/MMscf	=	2.32E-09 lb/MMBTU
	1.80E-06 lb/MMscf	=	1.74E-09 lb/MMBTU
	2.10E-03 lb/MMscf	=	2.03E-06 lb/MMBTU
	1.20E-06 lb/MMscf	=	1.16E-09 lb/MMBTU
	1.80E-06 lb/MMscf		1.74E-09 lb/MMBTU
	1.20E-06 lb/MMscf		1.16E-09 lb/MMBTU
	1.80E-06 lb/MMscf		1.74E-09 lb/MMBTU
	1.80E-06 lb/MMscf		1.74E-09 lb/MMBTU
	1.20E-06 lb/MMscf		1.16E-09 lb/MMBTU
	1.20E-03 lb/MMscf		1.16E-06 lb/MMBTU
	3.00E-06 lb/MMscf		2.90E-09 lb/MMBTU
	2.80E-06 lb/MMscf		2.70E-09 lb/MMBTU
	7.50E-02 lb/MMscf		7.24E-05 lb/MMBTU
	1.80E+00 lb/MMscf		1.74E-03 lb/MMBTU
	1.80E-06 lb/MMscf		1.74E-09 lb/MMBTU
	6.10E-04 lb/MMscf		5.89E-07 lb/MMBTU
	1.70E-05 lb/MMscf		1.64E-08 lb/MMBTU
	5.00E-06 lb/MMscf		4.83E-09 lb/MMBTU
	3.40E-03 lb/MMscf		3.28E-06 lb/MMBTU
From AP-42 (7/98); Tables 1.4-4	2.00E-04 lb/MMscf		1.93E-07 lb/MMBTU
	1.20E-05 lb/MMscf		1.16E-08 lb/MMBTU
	1.10E-03 lb/MMscf		1.06E-06 lb/MMBTU
	1.40E-03 lb/MMscf		1.35E-06 lb/MMBTU
	8.40E-05 lb/MMscf		8.11E-08 lb/MMBTU
From AP-42 (7/98); Tables 1.4-4	3.80E-04 lb/MMscf		3.67E-07 lb/MMBTU
	2.60E-04 lb/MMscf		2.51E-07 lb/MMBTU
	2.10E-03 lb/MMscf		2.03E-06 lb/MMBTU
	2.40E-05 lb/MMscf		2.32E-08 lb/MMBTU

Notes

(1) Criteria pollutant emission provided in lb/hr from vendor data.
HAP emission factors referenced from AP-42, Chapter 1.4
CO2, CH4 and N2O emission factors based on 40 CFR 98 Table C-2
Sulfuric Acid Mist (as H_2SO_4) emissions provided by vendor, based on 10% conversion

(2) If emission factor provided as lb/hr, those emission factors are assumed for emissions (lb/hr), OR
Calculated as: Boiler Size (MMBTU/hr) **X** Emission Factor (lbs/MMBTU)

(3) Maximum emissions assumed to same as average emissions

(4) Calculated as: Emissions (lbs/hr) **X** Annual Operation (hrs/yr) ÷ 2,000 lbs/ton

(5) CO2e emissions = CO2 Emissions *CO2 GWP + CH4 Emissions * CH4 GWP + N2O Emissions * N2O GWP

Appendix A: Emission Calculations
Emergency Generator Emissions

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Emergency Diesel Generator Emission Calculations

Emission calculations shown below depict emissions from an emergency use diesel-fired generator engine with a maximum horsepower rating of 1500 kW (2,012 HP). Emission estimates are based on a maximum annual operating time of 100 non-emergency hours per year.

Pollutant	Annual Operation (hrs/yr)	Limited Annual Operation (hrs/yr)	Engine Size (HP)	Emission Factor (1) (lbs/HP-hr)	Emissions (Potential to Emit)			
					Average (2) (lbs/hr)	Maximum(3) (lbs/hr)	Annual (4) (tons/yr)	Limited Annual (4) (tons/yr)
Particulate Matter (PM_{10})	500	100	2,012	0.000331	0.665	0.665	0.17	0.033
Particulate Matter ($PM_{2.5}$)	500	100	2,012	0.000331	0.665	0.665	0.17	0.033
Sulfur Oxides (SO_x)	500	100	2,012	0.000012	0.024	0.024	0.01	0.001
Nitrogen Oxides (NO_x)(5)	500	100	2,012	0.010582	21.291	21.291	5.32	1.065
Carbon Monoxide (CO)	500	100	2,012	0.005754	11.577	11.577	2.89	0.579
Total Volatile Organic Compounds (VOC)(5)	500	100	2,012	0.000705	1.419	1.419	0.35	0.071
Sulfuric Acid Mist (as H_2SO_4)	500	100	2,012	0.000002	0.003	0.003	7.65E-04	0.00015
1,3-Butadiene	500	100	2,012	0.00E+00	0.000	0.000	0.00E+00	0.000
Acenaphthene	500	100	2,012	3.32E-08	0.000	0.000	1.67E-05	0.000
Acenaphthylene	500	100	2,012	6.55E-08	1.3E-04	1.3E-04	3.29E-05	6.6E-06
Acetaldehyde	500	100	2,012	1.79E-07	3.6E-04	3.6E-04	8.99E-05	1.80E-05
Acrolein	500	100	2,012	5.59E-08	1.1E-04	1.1E-04	2.81E-05	5.62E-06
Anthracene	500	100	2,012	8.72E-09	1.8E-05	1.8E-05	4.39E-06	8.78E-07
Benz(a)anthracene	500	100	2,012	4.41E-09	8.9E-06	8.9E-06	2.22E-06	4.44E-07
Benzene	500	100	2,012	5.50E-06	0.011	0.011	2.77E-03	5.54E-04
Benzo(a)pyrene	500	100	2,012	1.82E-09	0.000	0.000	9.17E-07	1.83E-07
Benzo(b)fluoranthene	500	100	2,012	7.87E-09	1.6E-05	1.6E-05	3.96E-06	7.92E-07
Benzo(g,h,i)perylene	500	100	2,012	3.94E-09	7.9E-06	7.9E-06	1.98E-06	3.97E-07
Benzo(k)fluoranthene	500	100	2,012	1.55E-09	3.1E-06	3.1E-06	7.78E-07	1.56E-07
Chrysene	500	100	2,012	1.09E-08	2.2E-05	2.2E-05	5.46E-06	1.09E-06
Dibenzo(a,h)anthracene	500	100	2,012	2.45E-09	4.9E-06	4.9E-06	1.23E-06	2.47E-07
Fluoranthene	500	100	2,012	2.86E-08	5.8E-05	5.8E-05	1.44E-05	2.88E-06
Fluorene	500	100	2,012	9.08E-08	1.8E-04	1.8E-04	4.57E-05	9.13E-06
Formaldehyde	500	100	2,012	5.60E-07	0.001	0.001	2.81E-04	5.63E-05
Indeno(1,2,3-cd)pyrene	500	100	2,012	2.94E-09	5.9E-06	5.9E-06	1.48E-06	2.95E-07
Naphthalene	500	100	2,012	9.22E-07	0.002	0.002	4.64E-04	9.28E-05
Phenanathrene	500	100	2,012	2.89E-07	5.8E-04	5.8E-04	1.46E-04	2.91E-05
Propylene	500	100	2,012	1.98E-05	0.040	0.040	9.95E-03	1.99E-03
Pyrene	500	100	2,012	2.63E-08	5.3E-05	5.3E-05	1.32E-05	2.65E-06
Toluene	500	100	2,012	1.99E-06	0.004	0.004	1.00E-03	2.00E-04
Xylene (mixed isomers)	500	100	2,012	1.37E-06	0.003	0.003	6.89E-04	1.38E-04
Carbon Dioxide (CO_2 or CO_2e)	500	100	2,012	1.24E+00	2,492.485	2492.485	623.12	124.62
Methane (CH_4)	500	100	2,012	5.02E-05	0.101	0.101	0.03	0.005
Nitrous Oxide (N_2O)	500	100	2,012	1.00E-05	0.020	0.020	5.06E-03	0.001
CO_2e	500	100	2,012	--	2501.04	2501.04	625.26	125.05

CI ICE Tier 2	0.15 g/HP-hr	=	0.000331 lbs/HP-hr
CI ICE Tier 2	0.15 g/HP-hr	=	0.000331 lbs/HP-hr
ULSD sulfur content	15 ppm S in Fuel	=	0.000012 lbs/HP-hr
Vendor Information	4.80 g/HP-hr	=	0.010582 lbs/HP-hr
CI ICE Tier 2	2.61 g/HP-hr	=	0.005754 lbs/HP-hr
Vendor Information	0.32 g/HP-hr	=	0.000705 lbs/HP-hr
SO2 to SO3 Conversion	1.52E-06 lbs/HP-hr	=	1.52E-06 lbs/HP-hr
AP-42 (10/96); Tables 3.4-3 and 3.4-4	0.00E+00 lbs/MMBtu	=	0.00E+00lbs/HP-hr
	4.68E-06 lbs/MMBtu	=	3.32E-08lbs/HP-hr
	9.23E-06 lbs/MMBtu	=	6.55E-08lbs/HP-hr
	2.52E-05 lbs/MMBtu	=	1.79E-07lbs/HP-hr
	7.88E-06 lbs/MMBtu	=	5.59E-08lbs/HP-hr
	1.23E-06 lbs/MMBtu	=	8.72E-09lbs/HP-hr
	6.22E-07 lbs/MMBtu	=	4.41E-09lbs/HP-hr
	7.76E-04 lbs/MMBtu	=	5.50E-06lbs/HP-hr
	2.57E-07 lbs/MMBtu	=	1.82E-09lbs/HP-hr
	1.11E-06 lbs/MMBtu	=	7.87E-09lbs/HP-hr
	5.56E-07 lbs/MMBtu	=	3.94E-09lbs/HP-hr
	2.18E-07 lbs/MMBtu	=	1.55E-09lbs/HP-hr
	1.53E-06 lbs/MMBtu	=	1.09E-08lbs/HP-hr
	3.46E-07 lbs/MMBtu	=	2.45E-09lbs/HP-hr
	4.03E-06 lbs/MMBtu	=	2.86E-08lbs/HP-hr
	1.28E-05 lbs/MMBtu	=	9.08E-08lbs/HP-hr
	7.89E-05 lbs/MMBtu	=	5.60E-07lbs/HP-hr
	4.14E-07 lbs/MMBtu	=	2.94E-09lbs/HP-hr
	1.30E-04 lbs/MMBtu	=	9.22E-07lbs/HP-hr
	4.08E-05 lbs/MMBtu	=	2.89E-07lbs/HP-hr
	2.79E-03 lbs/MMBtu	=	1.98E-05lbs/HP-hr
	3.71E-06 lbs/MMBtu	=	2.63E-08lbs/HP-hr
	2.81E-04 lbs/MMBtu	=	1.99E-06lbs/HP-hr
	1.93E-04 lbs/MMBtu	=	1.37E-06lbs/HP-hr
NA	NA		NA
	NA		NA
40 CFR 98 Table C-2	7.40E+01 lbs/MMBtu	=	1.24E+00lbs/HP-hr
	3.00E-03 kg/MMBtu	=	5.02E-05lbs/HP-hr
	6.00E-04 kg/MMBtu	=	1.00E-05lbs/HP-hr

Notes

(1) Sources:
- PM_{10} and CO emission factors based on EPA emission certification for Tier 2 engine
- SO_x based on use of ULSD
- NO_x emission factors based CI ICE Tier 2 Standard for Nox + NMHC
- VOC emissions provided by vendor, who used emission factor from AP-42 Table 3.4-1
- Spectated organics: AP-42 Emission Factors
- CO2, CH_4 and N_2O emission factors based on 40 CFR 98 Table C-2
- Sulfuric Acid Mist (as H_2SO_4) emissions provided by vendor, based on 10% conversion

(2) Calculated as: Engine Size (HP) **X** Emission Factor (lbs/HP-hr)

(3) Maximum emissions assumed to same as average emissions

(4) Calculated as: Emissions (lbs/hr) **X** Annual Operation (hrs/yr) ÷ 2,000 lbs/ton

(5) NOx emissions are depicted at a rate of 4.8 g/hp-hr for conservative permitting purposes; however, NOx + NMHC emissions from the unit will not exceed 4.8 g/hp-hr, as specified in 40 CFR 60 Subpart IIII.

(6) CO2e emissions = CO2 Emissions *CO2 GWP + CH4 Emissions * CH4 GWP + N2O Emissions * N2O GWP

Appendix A: Emission Calculations
Fire Pump Emissions

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Emergency Fire Water Pump Emission Calculations

Emission calculations shown below depict emissions from an emergency use diesel-fired fire water pump engine with a maximum horsepower rating of 420 HP. Emission estimates are based on a maximum annual operating time of 100 non-emergency hours per year

Pollutant	Annual Operation (hrs/yr)	Limited Annual Operation (hrs/yr)	Engine Size (HP)	Emission Factor (1) (lbs/HP-hr)	Emissions (Potential to Emit) Average (2) (lbs/hr)	Maximum (3) (lbs/hr)	Annual (4) (tons/yr)	Limited Annual (4) (tons/yr)
Particulate Matter (PM_{10})	500	100	420	0.000331	0.139	0.139	0.035	0.0069
Particulate Matter ($PM_{2.5}$)	500	100	420	0.000331	0.139	0.139	0.035	0.0069
Sulfur Oxides (SO_x)	500	100	420	0.000012	0.005	0.005	0.001	0.00025
Nitrogen Oxides (NO_x)(5)	500	100	420	0.006614	2.778	2.778	0.694	0.139
Carbon Monoxide (CO)	500	100	420	0.005754	2.417	2.417	0.604	0.121
Total Volatile Organic Compounds (VOC)(5)	500	100	420	0.000882	0.370	0.370	0.093	0.019
Sulfuric Acid Mist (as H_2SO_4)	500	100	420	0.000001	0.0006	0.0006	1.50E-04	0.00003
1,3-Butadiene	500	100	420	2.77E-07	1.2E-04	1.2E-04	2.91E-05	5.8E-06
Acenaphthene	500	100	420	1.01E-08	4.2E-06	4.2E-06	1.06E-06	2.1E-07
Acenaphthylene	500	100	420	3.59E-08	1.5E-05	1.5E-05	3.77E-06	7.5E-07
Acetaldehyde	500	100	420	5.44E-06	0.002	0.002	5.71E-04	1.1E-04
Acrolein	500	100	420	6.56E-07	2.8E-04	2.8E-04	6.89E-05	1.4E-05
Anthracene	500	100	420	1.33E-08	5.6E-06	5.6E-06	1.39E-06	2.8E-07
Benz(a)anthracene	500	100	420	1.19E-08	5.0E-06	5.0E-06	1.25E-06	2.5E-07
Benzene	500	100	420	6.62E-06	0.003	0.003	6.95E-04	1.4E-04
Benzo(a)pyrene	500	100	420	1.33E-09	0.000	0.000	1.40E-07	2.8E-08
Benzo(b)fluoranthene	500	100	420	7.03E-10	0.000	0.000	7.38E-08	1.5E-08
Benzo(g,h,i)perylene	500	100	420	3.47E-09	0.000	0.000	3.64E-07	7.3E-08
Benzo(k)fluoranthene	500	100	420	1.10E-09	0.000	0.000	1.15E-07	2.3E-08
Chrysene	500	100	420	2.50E-09	0.000	0.000	2.63E-07	5.3E-08
Dibenzo(a,h)anthracene	500	100	420	4.13E-09	0.000	0.000	4.34E-07	8.7E-08
Fluoranthene	500	100	420	5.40E-08	0.000	0.000	5.67E-06	1.1E-06
Fluorene	500	100	420	2.07E-07	0.000	0.000	2.17E-05	4.3E-06
Formaldehyde	500	100	420	8.37E-06	0.004	0.004	8.79E-04	1.8E-04
Indeno(1,2,3-cd)pyrene	500	100	420	2.66E-09	0.000	0.000	2.79E-07	5.6E-08
Naphthalene	500	100	420	6.01E-07	2.5E-04	2.5E-04	6.31E-05	1.3E-05
Phenanathrene	500	100	420	2.09E-07	8.8E-05	8.8E-05	2.19E-05	4.4E-06
Propylene	500	100	420	1.83E-05	0.008	0.008	1.92E-03	3.8E-04
Pyrene	500	100	420	3.39E-08	0.000	0.000	3.56E-06	7.1E-07
Toluene	500	100	420	2.90E-06	0.001	0.001	3.05E-04	6.1E-05
Xylene (mixed isomers)	500	100	420	2.02E-06	0.001	0.001	2.12E-04	4.2E-05
Carbon Dioxide (CO_2 or CO_2e)	500	100	420	1.16	488.7	488.7	122.18	24.4
Methane (CH_4)	500	100	420	4.72E-05	0.020	0.020	0.005	0.001
Nitrous Oxide (N_2O)	500	100	420	9.44E-06	0.004	0.004	9.91E-04	0.0002
CO_2e	500	100	420	--	490.40	490.40	122.60	24.52

CI ICE Tier 3	0.15 g/HP-hr	=	0.000331 lbs/HP-hr
CI ICE Tier 3	0.15 g/HP-hr	=	0.000331 lbs/HP-hr
ULSD sulfur content	15 ppm S in Fuel	=	0.000012 lbs/HP-hr
Vendor Information	3.00 g/HP-hr	=	0.006614 lbs/HP-hr
CI ICE Tier 3	2.61 g/HP-hr	=	0.005754 lbs/HP-hr
Vendor Information	0.40 g/HP-hr	=	0.000882 lbs/HP-hr
SO_2 to SO_3 Conversion	1.43E-06 lbs/HP-hr	=	1.43E-06lbs/HP-hr
AP-42 (10/96); Table 3.3-2	3.91E-05 lbs/MMBtu	=	2.77E-07lbs/HP-hr
	1.42E-06 lbs/MMBtu	=	1.01E-08lbs/HP-hr
	5.06E-06 lbs/MMBtu	=	3.59E-08lbs/HP-hr
	7.67E-04 lbs/MMBtu	=	5.44E-06lbs/HP-hr
	9.25E-05 lbs/MMBtu	=	6.56E-07lbs/HP-hr
	1.87E-06 lbs/MMBtu	=	1.33E-08lbs/HP-hr
	1.68E-06 lbs/MMBtu	=	1.19E-08lbs/HP-hr
	9.33E-04 lbs/MMBtu	=	6.62E-06lbs/HP-hr
	1.88E-07 lbs/MMBtu	=	1.33E-09lbs/HP-hr
	9.91E-08 lbs/MMBtu	=	7.03E-10lbs/HP-hr
	4.89E-07 lbs/MMBtu	=	3.47E-09lbs/HP-hr
	1.55E-07 lbs/MMBtu	=	1.10E-09lbs/HP-hr
	3.53E-07 lbs/MMBtu	=	2.50E-09lbs/HP-hr
	5.83E-07 lbs/MMBtu	=	4.13E-09lbs/HP-hr
	7.61E-06 lbs/MMBtu	=	5.40E-08lbs/HP-hr
	2.92E-05 lbs/MMBtu	=	2.07E-07lbs/HP-hr
	1.18E-03 lbs/MMBtu	=	8.37E-06lbs/HP-hr
	3.75E-07 lbs/MMBtu	=	2.66E-09lbs/HP-hr
	8.48E-05 lbs/MMBtu	=	6.01E-07lbs/HP-hr
	2.94E-05 lbs/MMBtu	=	2.09E-07lbs/HP-hr
	2.58E-03 lbs/MMBtu	=	1.83E-05lbs/HP-hr
	4.78E-06 lbs/MMBtu	=	3.39E-08lbs/HP-hr
	4.09E-04 lbs/MMBtu	=	2.90E-06lbs/HP-hr
	2.85E-04 lbs/MMBtu	=	2.02E-06lbs/HP-hr
NA	NA		NA
	NA		NA
40 CFR 98 Table C-2	7.40E+01 kg/MMBtu	=	1.16E+00lbs/HP-hr
	3.00E-03 kg/MMBtu	=	4.72E-05lbs/HP-hr
	6.00E-04 kg/MMBtu	=	9.44E-06lbs/HP-hr

Notes

(1) Sources:
- PM_{10} and CO emission factors based on EPA emission certification for Tier 3 engine
- SO_x based use of ULSD
- NO_x emission factors based CI ICE Tier 23Standard for Nox + NMHC
- VOC emissions provided by vendor
- Spectated organics: AP-42 Emission Factors
- CO2, CH_4 and N_2O emission factors based on 40 CFR 98 Table C-2
- Sulfuric Acid Mist (as H_2SO_4) emissions provided by vendor, based on 10% conversion

(2) Calculated as: Engine Size (HP) **X** Emission Factor (lbs/HP-hr)

(3) Maximum emissions assumed to same as average emissions

(4) Calculated as: Emissions (lbs/hr) **X** Annual Operation (hrs/yr) ÷ 2,000 lbs/ton

(5) NOx emissions are depicted at a rate of 3.0 g/hp-hr for conservative permitting purposes; however, NOx + NMHC emissions from the unit will not exceed 3.0 g/hp-hr, as specified in 40 CFR 60 Subpart IIII.

(6) CO2e emissions = CO2 Emissions *CO2 GWP + CH4 Emissions * CH4 GWP + N2O Emissions * N2O GWP

Appendix A: Emission Calculations
Fugitive Dust Emissions - Paved Roads

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

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)
Ammonia Delivery Truck (2/wk;one-way)	1.0	0.3	0.3	41.0	11.7	2112	0.400	0.1	41.7
Fuel Oil Delivery Truck (2/yr; one-way)	1.0	0.0	0.0	41.0	0.2	2112	0.400	0.0	0.8
Tradesmen/Delivery Trucks (15/wk; one-way)	3.0	2.1	6.4	4.5	28.9	2112	0.400	2.6	938.6
Ammonia Delivery Truck (2/wk;one-way)	1.0	0.3	0.3	16.0	4.6	2112	0.400	0.1	41.7
Fuel Oil Delivery Truck (2/yr; one-way)	1.0	0.0	0.0	16.0	0.1	2112	0.400	0.0	0.8
Tradesmen/Delivery Trucks (15/wk; one-way)	3.0	2.1	6.4	2.6	16.7	2112	0.400	2.6	938.6
		Totals	**13.4**		**62.2**			**5.4**	**1962.2**

Average Vehicle Weight Per Trip = 4.6 tons/trip
Average Miles Per Trip = 0.40 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 =	4.6	4.6	4.6	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 = 125 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 =	0.415	0.083	0.0204	lb/mile
Mitigated Emission Factor, Eext =	0.380	0.076	0.0186	lb/mile

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)
Ammonia Delivery Truck (2/wk;one-way)	0.01	0.00	0.00
Fuel Oil Delivery Truck (2/yr; one-way)	0.00	0.00	0.00
Tradesmen/Delivery Trucks (15/wk; one-way)	0.18	0.04	0.01
Ammonia Delivery Truck (2/wk;one-way)	0.01	0.00	0.00
Fuel Oil Delivery Truck (2/yr; one-way)	0.00	0.00	0.00
Tradesmen/Delivery Trucks (15/wk; one-way)	0.18	0.04	0.01
Totals	**0.37**	**0.07**	**0.02**

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
Screening Modeling - 185-foot Stack

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

			1	2	3	4	5	6	7	8	9	10	11				
Operating Scenarios			-15°F, Gas fuel, 1 GT @ 100% load	-15°F, Gas fuel, 1 GT @ 75% load	-15°F, Gas fuel, 1 GT @ 62.0021% load	59°F, Gas fuel, 1 GT @ 100% load, EC on	59°F, Gas fuel, 1 GT @ 100% load	59°F, Gas fuel, 1 GT @ 75% load	59°F, Gas fuel, 1 GT @ 29.3864% load	105°F, Gas fuel, 1 GT @ 100% load, EC on	105°F, Gas fuel, 1 GT @ 100% load	105°F, Gas fuel, 1 GT @ 75% load	105°F, Gas fuel, 1 GT @ 35.6867% load	Cold Start	Warm Start	Hot Start	Shutdown
Stack Parameters																	
Stack Temperature	°F		183.7	166.8	163.9	182.5	181.7	168.7	155.8	210.1	203.4	193.7	177.9	156.0	156.0	156.0	156.0
Stack Mass flow, including Permitting Margin, per stack	lb/h		6886700	5541700	5029900	6799200	6804700	5486500	3661000	6520600	5985700	5037600	3628400				
Margined exhaust vol flow (incl. permitting margin)	Mft3/h		116.22	91.069	82.212	115.03	114.86	90.7	59.1	116.28	105.45	87.372	61.278				
Margined exhaust vol flow (incl. permitting margin)	acfm		1937000	1517816.667	1370200	1917166.667	1914333.333	1511666.667	985000	1938000	1757500	1456200	1021300	974130	917470	789540	842540
Margined exhaust vol flow (incl. permitting margin) (24-hr and annual)	acfm		1937000	1517816.667	1370200	1917166.667	1914333.333	1511666.667	985000	1938000	1757500	1456200	1021300	985000	985000	985000	985000
Normalized Screening Model Impacts [(ug/m3)/(g/s)]																	
1-hour (max) - For 1-hour CO			1.09571	1.41147	1.51718	1.11125	1.11655	1.4049	1.80864	0.97805	1.09914	1.3132	1.68754	1.81548	1.85635	1.95206	1.91233
1-hour (annual max averaged over 5 years) - For 1-hour NO2			0.58934	0.74748	0.90227	0.59348	0.59496	0.74546	1.29573	0.55581	0.58749	0.70553	1.13672	1.30961	1.39156	1.63045	1.51544
8-hour (max) - For 8-hour CO			0.43749	0.5923	0.65337	0.4445	0.44692	0.58833	1.04477	0.38735	0.43799	0.53845	0.90286	1.10622	1.13171	1.38751	
24-hour (max) - For PM10 24-hour			0.1897	0.23874	0.26605	0.19195	0.1927	0.23759	0.41474	0.17367	0.19059	0.22287	0.32815	0.42154	0.42154	0.42154	
24-hour (annual max averaged over 5 years) - For 24-hr PM2.5			0.15677	0.21089	0.23416	0.15923	0.16011	0.20939	0.35179	0.13854	0.15603	0.19087	0.29895	0.3524	0.3524	0.3524	
Annual (max of 5 years) - for PM10 Annual and NO2 Annual			0.01798	0.02549	0.02865	0.01831	0.01842	0.02528	0.04175	0.01566	0.01792	0.02271	0.03473	0.03915	0.03915	0.03915	
Annual (averaged over 5 years) - For annual PM2.5			0.01515	0.02167	0.02451	0.01542	0.01552	0.02149	0.03657	0.01315	0.01504	0.01921	0.03035	0.03653	0.03653	0.03653	
Max Hourly Emission Rates (lb/hr)																	
NO2			30.90	12.90	30.40	10.60	29.60	29.10	10.50	29.00	27.40	10.20	27.40	11	8	5	2
CO			18.80	7.80	18.50	6.40	18.00	17.70	6.40	17.70	16.70	6.20	16.70	266	230	209	190
PM10			13.90	8.68	13.80	7.70	13.70	13.60	7.86	13.60	13.30	7.88	13.30	14	14	14	14
PM2.5			13.90	8.68	13.80	7.70	13.70	13.60	7.86	13.60	13.30	7.88	13.30	14	14	14	14
8- Hr Average Emission Rates (lb/hr)																	
NO2			30.90	12.90	30.40	10.60	29.60	29.10	10.50	29.00	27.40	10.20	27.40				
CO			18.80	7.80	18.50	6.40	18.00	17.70	6.40	17.70	16.70	6.20	16.70	76	67	154	
PM10			13.90	8.68	13.80	7.70	13.70	13.60	7.86	13.60	13.30	7.88	13.30				
PM2.5			13.90	8.68	13.80	7.70	13.70	13.60	7.86	13.60	13.30	7.88	13.30				
24- Hr Average Emission Rates (lb/hr)																	
NO2			30.90	12.90	30.40	10.60	29.60	29.10	10.50	29.00	27.40	10.20	27.40				
CO			18.80	7.80	18.50	6.40	18.00	17.70	6.40	17.70	16.70	6.20	16.70				
PM10			13.90	8.68	13.80	7.70	13.70	13.60	7.86	13.60	13.30	7.88	13.30	13.9	13.8	13.7	
PM2.5			13.90	8.68	13.80	7.70	13.70	13.60	7.86	13.60	13.30	7.88	13.30	13.9	13.8	13.7	
Annual Average Emission Rates (lb/hr)																	
NO2			30.90	12.90	30.40	10.60	29.60	29.10	10.50	29.00	27.40	10.20	27.40	38.1	38.1	38.1	
CO			18.80	7.80	18.50	6.40	18.00	17.70	6.40	17.70	16.70	6.20	16.70				
PM10			13.90	8.68	13.80	7.70	13.70	13.60	7.86	13.60	13.30	7.88	13.30	38.1	38.1	38.1	
PM2.5			13.90	8.68	13.80	7.70	13.70	13.60	7.86	13.60	13.30	7.88	13.30	38.1	38.1	38.1	
Hourly Emission Rates (g/s)																	
NO2			3.89	1.63	3.8304	1.34	3.73	3.67	1.32	3.65	3.45	1.29	3.45	1.4473	1.0453	0.6048	0.2602
CO			2.37	0.98	2.33	0.81	2.27	2.23	0.81	2.23	2.10	0.78	2.10	33.4800	28.9800	26.3844	23.9450
PM10			1.75	1.09	1.74	0.97	1.73	1.71	0.99	1.71	1.68	0.99	1.68	1.7064	1.7010	1.7325	1.7161
PM2.5			1.75	1.09	1.74	0.97	1.73	1.71	0.99	1.71	1.68	0.99	1.68	1.7064	1.7010	1.7325	1.7161
8- Hr Average Emission Rates (g/s)																	
NO2			3.89	1.63	3.83	1.34	3.73	3.67	1.32	3.65	3.45	1.29	3.45				
CO			2.37	0.98	2.33	0.81	2.27	2.23	0.81	2.23	2.10	0.78	2.10	9.6029	8.3922	19.4657	
PM10			1.75	1.09	1.74	0.97	1.73	1.71	0.99	1.71	1.68	0.99	1.68				
PM2.5			1.75	1.09	1.74	0.97	1.73	1.71	0.99	1.71	1.68	0.99	1.68				
24- Hr Average Emission Rates (g/s)																	
NO2			3.89	1.63	3.83	1.34	3.73	3.67	1.32	3.65	3.45	1.29	3.45				
CO			2.37	0.98	2.33	0.81	2.27	2.23	0.81	2.23	2.10	0.78	2.10				
PM10			1.75	1.09	1.74	0.97	1.73	1.71	0.99	1.71	1.68	0.99	1.68	1.7477	1.7407	1.7311	
PM2.5			1.75	1.09	1.74	0.97	1.73	1.71	0.99	1.71	1.68	0.99	1.68	1.7477	1.7407	1.7311	
Annual Average Emission Rates (g/s)																	
NO2			3.89	1.63	3.83	1.34	3.73	3.67	1.32	3.65	3.45	1.29	3.45	4.7998	4.7998	4.7998	
CO			2.37	0.98	2.33	0.81	2.27	2.23	0.81	2.23	2.10	0.78	2.10				
PM10			1.75	1.09	1.74	0.97	1.73	1.71	0.99	1.71	1.68	0.99	1.68	4.7998	4.7998	4.7998	
PM2.5			1.75	1.09	1.74	0.97	1.73	1.71	0.99	1.71	1.68	0.99	1.68	4.79976	4.80	4.80	
Screening Modeling Estimated Impacts (ug/m3)		SIL															
NO2 1-hr		7.5	2.29	1.21	3.46	0.79	2.22	2.73	1.71	2.03	2.03	0.91	3.92	1.90	1.45	0.99	
NO2 Annual		1.0	0.07	0.04	0.11	0.02	0.07	0.09	0.06	0.06	0.06	0.03	0.12	0.19	0.19	0.19	
CO 1-hr		2000.0	2.60	1.39	3.54	0.90	2.53	3.13	1.46	2.18	2.31	1.03	3.55	60.78	53.80	51.50	45.79
CO 8-hr		500	1.04	0.58	1.52	0.36	1.01	1.31	0.84	0.86	0.92	0.42	1.90	10.62	9.50	27.01	
PM10 24-hr		5	0.33	0.26	0.46	0.19	0.33	0.41	0.41	0.30	0.32	0.22	0.55	0.72	0.72	0.73	
PM10 Annual		1	0.03	0.03	0.05	0.02	0.03	0.04	0.04	0.03	0.03	0.02	0.06	0.19	0.19	0.19	
PM2.5 24-hr		1.2	0.27	0.23	0.41	0.15	0.28	0.36	0.35	0.24	0.26	0.19	0.50	0.62	0.61	0.61	
PM2.5 Annual		0.3	0.03	0.02	0.04	0.01	0.03	0.04	0.04	0.02	0.03	0.02	0.05	0.18	0.18	0.18	

Appendix A: Emission Calculations
Ancillary Equipment Modeling Parameters

Company Name: Maple Creek Energy LLC
Source Address: W CR 1040 N .5 MI S & SR 63 .4 MI W, Fairbanks, Indiana 47849
Permit Number SSM: 153-49550-00056
Permit Number SPM: 153-50217-00056
Reviewer: Tamera Wessel

Ancillary Equipment		Auxiliary Boiler	Emergency Generator	Emergency Fire Pump
Stack Parameters				
Stack Temperature	°F	300.0	900.0	850.0
exhaust vol flow	acfm	26700	17300	2200
Max Hourly Emission Rates (lb/hr)				
NO2		3.55	0.24	0.03
CO		3.55	11.58	2.42
PM10		0.72	0.67	0.14
PM2.5		0.72	0.67	0.14
8- Hr Average Emission Rates (lb/hr)				
NO2		3.55	21.29	2.78
CO		3.55	11.58	2.42
PM10		0.72	0.67	0.14
PM2.5		0.72	0.67	0.14
24- Hr Average Emission Rates (lb/hr)				
NO2		3.55	0.89	0.12
CO		3.55	0.21	0.10
PM10		0.72	0.03	0.01
PM2.5		0.72	0.03	0.01
Annual Average Emission Rates (lb/hr)				
NO2		3.55	0.24	0.03
CO		3.55	0.13	0.03
PM10		0.72	0.01	0.00
PM2.5		0.72	0.01	0.00
Hourly Emission Rates (g/s)				
NO2		0.4473	0.0306	0.0040
CO		0.4473	1.4587	0.3045
PM10		0.0907	0.0838	0.0175
PM2.5		0.0907	0.0838	0.0175
8- Hr Average Emission Rates (g/s)				
NO2		0.4473	2.6827	0.3500
CO		0.4473	1.4587	0.3045
PM10		0.0907	0.0838	0.0175
PM2.5		0.0907	0.0838	0.0175
24- Hr Average Emission Rates (g/s)				
NO2		0.4473	0.1118	0.0146
CO		0.4473	0.0270	0.0127
PM10		0.0907	0.0035	0.0007
PM2.5		0.0907	0.0035	0.0007
Annual Average Emission Rates (g/s)				
NO2		0.4473	0.0306	0.0040
CO		0.4473	0.0167	0.0035
PM10		0.0907	0.0010	0.0002
PM2.5		0.0907	0.0010	0.0002

Indiana Department of Environmental Management
Office of Air Quality

Appendix B
Best Available Control Technology (BACT) Analysis Determination

Source Description and Location

Source Name:	**Maple Creek Energy LLC**
Source Location:	**W CR 1040 N 0.5 miles South and SR 63 0.4 miles West, Fairbanks, IN 47849**
County:	**Sullivan**
SIC Code:	**4911 (Electric Services)**
Significant Source Modification No.:	**153-49550-00056**
Significant Permit Modification No.:	**153-50217-00056**
Permit Reviewer:	**Tamera Wessel**

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 new combined cycle power generation plant, owned and operated by Maple Creek Energy LLC. The source submitted an application on September 5, 2025, relating to the construction and operation of a new stationary combined-cycle electric generating facility.

Potential emissions (PTE) will exceed major source thresholds for NOx and CO. Therefore, a BACT review is required for this source for NOx and CO. In addition, PM, PM10, PM2.5, H_2SO_4 and GHGs have been reviewed due to each of these pollutants exceeding PSD significant levels, and VOC emissions from the natural gas-fired combined cycle system (CTG-01) have been reviewed due to this unit being subject to 326 IAC 8-1-6 (VOC BACT).

Proposed New Emission Units

The Office of Air Quality (OAQ) has reviewed an application, submitted by Maple Creek Energy LLC on September 5, 2025, relating to the construction and operation of a combined-cycle electric generating facility.

The following is a list of the new emission units and pollution control device(s):

(a) One (1) natural gas-fired combined cycle system, identified as CTG-01, approved in 2026 for construction, with a maximum heat input capacity of 4,253 MMBtu per hour, equipped with a combustion turbine generator (CTG) exhausting to a heat recovery steam generator (HRSG) which will feed steam to one steam turbine generator (STG) and one air-cooled condenser (ACC), using dry-low-NOx (DLN) combustors and selective catalytic reduction (SCR) for control of NOx emissions, and an oxidation catalyst as VOC and CO control, and exhausting to stack CTG-01, with continuous emissions monitors (CEMS) for NOx and CO.

Under 40 CFR 60, Subpart KKKK, CTG-01 is an affected facility because it was constructed after February 18, 2005, has a maximum heat input capacity of greater than 10 MMBtu/hr, and is a stationary combustion turbine (CTG).

Under 40 CFR 60, Subpart TTTTa, CTG-01 was constructed after May 23, 2023, has a base load rating greater than 250 MMBtu/hr of fossil fuel, and serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system, and is an affected unit.

(b) One (1) natural gas-fired auxiliary boiler, identified as AUX, equipped with ultra-low-NOx burners, approved in 2026 for construction, with a heat input capacity of 96 MMBtu/hr, and exhausting to stack AUX.

Under 40 CFR 60, Subpart Dc, AUX is an affected facility because it was constructed after June 9, 1989, has a maximum design heat input capacity of less than 100 MMBtu/hr, but greater than 10 MMBtu/hr, and is considered a small steam generating unit.

(c) One (1) diesel-fired emergency generator using ultra-low-sulfur-distillate (ULSD), identified as EG, approved in 2026 for construction, with a maximum output rating of 2,012 horsepower (hp), and exhausting to stack EG.

Under 40 CFR 60, Subpart IIII, EG is an affected facility because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, was manufactured after April 1, 2006, and is not a fire pump engine.

Under 40 CFR 63, Subpart ZZZZ, EG is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

(d) One (1) diesel-fired emergency fire pump engine using ultra-low-sulfur-distillate (ULSD), identified as FP, approved in 2026 for construction, with a maximum output rating of 420 horsepower (hp), and exhausting to stack FP.

Under 40 CFR 60, Subpart IIII, FP is an affected facility because it is a 2026 model year diesel-fired emergency stationary compression ignition (CI) internal combustion engine (ICE), that commenced construction after July 11, 2005, and was manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Under 40 CFR 63, Subpart ZZZZ, FP is an affected facility because it was constructed after June 12, 2006, and is considered a new emergency stationary reciprocating internal combustion engine (RICE) at an area source of HAPs.

Summary of the Best Available Control Technology (BACT) Process

IDEM, OAQ conducts BACT analyses 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*, which outlines the steps for conducting a top-down BACT analysis. Those steps are listed below.

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;
(4) Evaluate the most effective controls and document the results; and
(5) Select BACT.

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.

Summary of Combined-Cycle Gas Turbine

$PM/PM_{10}/PM_{2.5}$ BACT Determination: Combined-Cycle Gas Turbine

Emissions of PM, PM_{10}, and $PM_{2.5}$ from combustion can occur as a result of trace inert solids contained in the fuel and as products of incomplete combustion that agglomerate or condense to form particles. PM, PM_{10}, and $PM_{2.5}$ emissions can also result from the formation of ammonium salts due to the conversion of SO_2 to SO_3, which is then available to react with NH_3 to form ammonium sulfates. All of the PM, PM_{10}, and $PM_{2.5}$ emitted from the combined-cycle combustion turbine generator (CTG) is conservatively assumed to be less than 2.5 microns in diameter. Therefore, the PM, PM_{10}, and $PM_{2.5}$ emission rates are assumed to be the same.

Step 1: Identify Potential Control Technologies

Emissions of PM, PM_{10}, and $PM_{2.5}$ are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. In cases where the material being emitted is organic, particulate matter may be controlled through a combustion process. Generally, PM, PM_{10}, and $PM_{2.5}$ emissions are controlled through one of the following mechanisms:

(1) Fabric Filter Dust Collectors (Baghouses).
(2) Electrostatic Precipitators (ESP); and
(3) Wet Scrubbers;
(4) Cyclones or Multiclones;
(5) Fuel Specification; and
(6) Good Combustion Practices.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

The combined-cycle CTG proposed for the Facility will utilize natural gas as the sole fuel to minimize PM, PM_{10}, and $PM_{2.5}$ emissions. The combustion of clean-burning fuels is the most effective means for controlling particulate emissions from combustion equipment. Emissions of PM, PM_{10}, and $PM_{2.5}$ from the exhaust stack will be limited to 0.0058 lb/MMBtu (HHV).

Step 2: Eliminate Technically Infeasible Options

(a) Fabric Filtration

A fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal.

Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99 or 99.9%. The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake.

Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 5 to 20 inches of water.

Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation. Important process variables include particle characteristics, gas characteristics, and fabric properties. The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

The fabric filters are susceptible to corrosion and binding by moisture. Appropriate fabrics must be selected for specific process conditions. Accumulations of dust may present fire or explosion hazard. The typical waste stream inlet flow is 100-100,000 scfm (Standard) or 100,000-1,000,00 scfm (Custom). The natural gas fired combustion turbines generate low particulate matter emissions and have large exhaust flow rates, resulting in very low concentration of particulates.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Baghouse is not a technically feasible option for the combined cycle combustion turbine at this source.

(b) Electrostatic Precipitators

An electrostatic precipitator (ESP) is a particle control device that uses electrical forces to move the particles out of the flowing gas stream and onto collector plates. The particles are given an electrical charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field that forces the charged particles to the walls comes from electrodes maintained at high voltage in the center of the flow lane.

Once the particles are collected on the plates, they must be removed from the plates without re-entraining them into the gas stream. This is usually accomplished by knocking them loose from the plates, allowing the collected layer of particles to slide down into a hopper from which they are evacuated. Some precipitators remove the particles by intermittent or continuous washing with water. ESP control efficiencies can range from 95% to 99.9%.

Gas temperatures may be up to about 1,300 °F (dry) and Lower than 170 - 190 °F (wet). The typical waste stream inlet flow is 1,000 - 100,000 scfm (Wire-Pipe) and 100,000 - 1,000,000 scfm (Wire-Plate). Dry ESP efficiency varies significantly with dust resistivity. Air leakage and acid condensation may cause corrosion. ESPs are not generally suitable for highly variable processes. Natural-gas fired CCCTs generate low Particulate emissions and have large exhaust flow-rates, resulting in very low concentrations of

Particulates. Electrostatic precipitator (ESPs) would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of an electrostatic precipitator is not a technically feasible option for the combined cycle combustion turbine at this source.

(c) Wet scrubbers

A wet scrubber is an air pollution control device that removes particulate matter from waste gas streams primarily through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. The liquid containing the pollutant is then collected for disposal. There are numerous types of wet scrubbers that remove particulate matter. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream. In general, collection efficiency decreases as the particulate matter size decreases. Collection efficiencies also vary with scrubber type.

Collection efficiencies range from greater than 99% for venturi scrubbers to 40-60% (or lower) for simple spray towers. Wet scrubbers are smaller and more compact than baghouses or ESPs. They have lower capital costs and comparable operation and maintenance (O&M) costs. Wet scrubbers are particularly useful in the removal of particulate matter with the following characteristics:

(1) Sticky and/or hygroscopic materials (materials that readily absorb water);
(2) Combustible, corrosive and explosive materials;
(3) Particles which are difficult to remove in their dry form;
(4) PM in the presence of soluble gases; and
(5) PM in waste gas streams with high moisture content.

The primary disadvantage of wet scrubbers is that increased collection efficiency comes at the cost of increased pressure drop across the control system. Another disadvantage is that they are limited to lower waste gas flow rates and temperatures than ESPs or baghouses. Current wet scrubber designs accommodate air flow rates over 100,000 actual cubic feet per minute and temperatures of up to 750°F. The downstream corrosion or plume visibility problems can result unless the added moisture is removed from the gas stream.

Gas temperatures are between 40 to 750 °F. The typical waste stream inlet flow is 500 - 100,000 scfm (units in parallel can operate at greater flow rates). Effluent wastewater stream may require treatment. Sludge disposal may be costly. Wet scrubbers are particularly susceptible to corrosion. Natural gas-fired combustion turbines generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. A wet scrubber would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet scrubber is not a technically feasible option for the combined cycle combustion turbine at this source.

(d) Cyclones

Cyclones are simple mechanical devices commonly used to remove relatively large particles from gas streams. In industrial applications, cyclones are often used as precleaners for the more sophisticated air pollution control equipment such as ESPs or baghouses. Cyclones are less efficient than wet scrubbers, baghouses, or ESPs.

Cyclones used as pre-cleaners are often designed to remove more than 80% of the particles that are greater than 20 microns in diameter. Smaller particles that escape the cyclone can then be collected by more efficient control equipment. This control technology may be more commonly used in industrial sites that generate a considerable amount of particulate matter, such as lumber companies, feed mills, cement plants, and smelters.

The gas temperature is about 1,000°F. The typical waste stream inlet flow is between 1.1 - 63,500 scfm (single) and up to 106,000 scfm (in parallel). Cyclones typically exhibit lower efficiencies when collecting smaller particles. High-efficiency units may require substantial pressure drop. Natural gas-fired combustion turbines generate low Particulate emissions and have large exhaust flow rates, resulting in very low concentrations of Particulates. Cyclones would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a cyclone is not a technically feasible option for the combined cycle combustion turbine at this source.

(e) Fuel Specifications

Combusting only clean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating PM, PM_{10}, and $PM_{2.5}$ emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Fuel Specifications is a technically feasible option for the combined cycle combustion turbine at this source.

(f) Good Combustion Practices

Good combustion practices as well as operation and maintenance of the combined cycle combustion turbines to keep them in good working order per the manufacturer's specifications will minimize PM, PM_{10}, and $PM_{2.5}$ emissions.

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 combined cycle combustion turbine at this source.

<u>Step 3: Ranking of Technically Feasible Control Options</u>

The following measures have been identified for control of PM, PM_{10}, and $PM_{2.5}$ resulting from the operation of the combined cycle combustion turbine.

(1) Fuel Specifications; and
(2) Good Combustion Practices

<u>Step 4: Evaluate Top Control Alternatives</u>

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) under Process Type Code 15.210 (Large Combustion Turbines - Natural Gas), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Summary of RBLC Database Review - Large Combustion Turbines - Natural Gas - PM/PM10/PM2.5

Facility	Permit Number & Date	RBLC ID #	Emission Unit	$PM/PM_{10}/PM_{2.5}$ Requirements
Maple Creek Energy LLC	Proposed	--	Combined Cycle Combustion Turbine Generator (4,253 MMBtu/hr)	**Control Method:** Good combustion practices and combusting pipeline-quality natural gas **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.0058 lb/MMBtu, excluding SU/SD *(proposed limit is based on vendor emissions values)* **$PM/PM_{10}/PM_{2.5}$ SU/SD Limits:** 1.9 tons/yr during SU/SD
Maple Creek Energy LLC	Existing T153-45909-00056 (06/19/2023)	IN-0365	Combined Cycle Combustion Turbine CTGB (4,200 MMBtu/hr)	**Control Method:** Pipeline-Quality Natural Gas and Good Combustion Practices **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.0074 lb/MMBtu, excluding SU/SD **$PM_{10}/PM_{2.5}$ SU/SD Limit:** 14.0 lb/event hot start
Maple Creek Energy II LLC	Proposed	--	Combined Cycle Combustion Turbine Generator (4,253 MMBtu/hr)	**Control Method:** Good combustion practices and combusting pipeline-quality natural gas **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.0058 lb/MMBtu, excluding SU/SD *(proposed limit is based on vendor emissions values)* **$PM/PM_{10}/PM_{2.5}$ SU/SD Limits:** 1.9 tons/yr during SU/SD
Golden Spread Electric Cooperative, Inc.	109148, PSD1358M2, GHG41M2 (08/14/25)	TX-1000	Simple-Cycle Turbine (2,033 MMBtu/hr)	**No $PM/PM_{10}/PM_{2.5}$ Emission Limits**
Duke Energy, Indiana, Inc. - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	Two (2) Combustion Turbines (4,254 MMBtu/hr)	**Control Method:** Good combustion practices and combusting pipeline-quality natural gas **PM Emission Limit:** 0.0042 lb/MMBtu, 3-Hr Avg. Excluding SU/SD
Wabash Valley Resources, LLC	167-45208-00091 (01/11/2024)	IN-0371	Integrated Gasification Combined Cycle Combustion Turbine (2,292 MMBtu/hr)	**No $PM/PM_{10}/PM_{2.5}$ Emission Limits**
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Combustion Turbine (4,671 MMBtu/hr)	**Control Method:** Good Combustion Practices **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 36.3 lb/hr with duct firing *(converts to 0.0078 lb/MMBtu)* 21.8 lb/hr without duct firing *(converts to 0.0047 lb/MMBtu)*
Entergy Texas, Inc. Orange County Advanced Power Station	166032 PSDTX1598 GHGPSDTX210 (03/13/2023)	TX-0939	Combined Cycle Turbines (1,215 MW and 6762 Btu/hr)	**Control Method:** Good Combustion Practices **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.0050 lb/MMBtu
Midland Cogeneration Venture Limited Partnership	10-23 (02/01/2023)	MI-0455	EUCTGHRSG1 (4,197.60 MMBtu/hr)	**Control Method:** Use of pipeline quality natural gas and Good Combustion Practices **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 34.4 lb/hr *(converts to 0.0082 lb/MMBtu)*
Lansing Board of Water and Light - Erickson Station	74-18D (12/20/2022)	MI-0454	EUCTGHRSG1 and EUCTGHRSG2 (667 MMBtu/hr, each)	**Control Method:** Use of pipeline quality natural gas, inlet air conditioning, and good combustion practices **$PM_{10}/PM_{2.5}$ Emission Limit:** 6.02 lb/hr *(converts to 0.0090 lb/MMBtu)* **No PM Limit**

Facility	Permit Number & Date	RBLC ID #	Emission Unit	$PM/PM_{10}/PM_{2.5}$ Requirements
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	Combined Cycle Combustion Turbine (3,647 MMBtu/hr)	**Control Method:** Good combustion practices **PM Emission Limit:** 0.0032 lbs/MMBtu with duct burner 0.0031 lbs/MMBtu w/o duct burner **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.0041 lbs/MMBtu
Alaska Gasline Development Corporation Liquefaction Plant	AQ1539CPT01 (07/07/2022)	AK-0088	(4) Combined Cycle Gas-Fired Turbines (384 MMBtu/hr, each)	**Control Method:** Good Combustion Practices and burning clean fuel (natural gas) **$PM/PM_{10}/PM_{2.5}$ Emission Limit 1:** 0.0070 lb/MMBtu, 3-hours **$PM/PM_{10}/PM_{2.5}$ Emission Limit 2:** 10% Opacity for 6 consecutive minutes
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Combined Cycle Natural Gas-Fired Combustion Turbine Generator with HRSG (3,064 MMBtu/hr)	**Control Method:** Good combustion practices, inlet air conditioning, use of pipeline quality natural gas **PM Emission Limit:** 5.70 lb/hr 0.002 lb/MMBtu **$PM_{10}/PM_{2.5}$ Emission Limit:** 19.10 lb/hr 0.005 lb/MMBtu
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/03/2022)	MI-0452	Combined Cycle Natural Gas-Fired Combustion Turbine Generator with HRSG (3,064 MMBtu/hr)	**Control Method:** Good combustion practices, inlet air conditioning, use of pipeline quality natural gas **PM Emission Limit:** 5.70 lb/hr 0.002 lb/MMBtu **$PM_{10}/PM_{2.5}$ Emission Limit:** 19.10 lb/hr 0.005 lb/MMBtu
Magnolia Power LLC- Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Combined Cycle Gas Turbine (5,081 MMBtu/hr)	**Control Method:** Use of gaseous fuel (pipeline-quality natural gas) and good combustion practices **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.008 lb/MMBtu 18.0 lb/hr during SU/SD
Mountain State Clean Energy LLC Maidsville	R14-0038 (01/05/2022)	WV-0033	Combustion Turbine and Duct Burner (1,275 MW)	**Control Method:** Clean Fuels and Good Combustion Practices **$PM/PM_{10}/PM_{2.5}$ Emission Limit 1:** 0.0060 lb/MMBtu, excluding SU/SD, With or without duct firing **$PM/PM_{10}/PM_{2.5}$ Emission Limit 2:** 25.32 lb/hr Excluding SU/SD, With or without duct firing
Shady Hills Energy Center, LLC	1010524-003-AC / PSD-FL-444A (06/07/2021)	FL-0371	Combustion Turbine and HRSG with Duct Firing (3,622 MMBtu/hr)	**Control Method:** Clean Fuels **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 1.4 gr/100 scf *(converts to 0.0020 lb/MMBtu)*
Renovo Energy Center LLC / Renovo PLT	18-00033B (04/29/2021)	PA-0334	Combustion Turbines with Duct Burners #1 and #2 (4,546 MMBtu/hr, each)	**Control Method:** SCR, Catalytic Oxidizer **PM Emission Limits:** 0.005 lb/MMBtu 22.5 lb/hr
Alabama Power Company / Plant Barry	503-1001 (11/09/2020)	AL-0328	Two (2) Combined Cycle Units (744 MW)	**Control Method:** N/A **$PM_{10}/PM_{2.5}$ Emission Limits:** 0.0040 lb/MMBtu 21.51 lb/hr

Facility	Permit Number & Date	RBLC ID #	Emission Unit	$PM/PM_{10}/PM_{2.5}$ Requirements
FG LA Complex	PSD-LA-812 (01/06/2020)	LA-0364	Natural Gas Cogeneration Units (2,222 MMBtu/hr)	**Control Method:** Use of pipeline quality natural gas or fuel gas and good combustion practices **$PM_{10}/PM_{2.5}$ Emission Limit:** 12.46 lb/hr *(converts to 0.0056 lb/MMBtu)*
Indeck Niles, LLC	75-16B (11/26/2019)	MI-0445	Natural Gas Combined-cycle Turbine (3,421 MMBtu/hr)	**Control Method:** Good combustion practices **PM Emission Limit:** 9.9 lb/hr *(converts to 0.0029 lb/MMBtu)* **$PM_{10}/PM_{2.5}$Emission Limit:** 19.8 lb/hr *(converts to 0.0058 lb/MMBtu)*
Thomas Township Energy, LLC	210-18 (8/21/2019)	MI-0442	Natural Gas Combined-cycle Turbine (625 MW, 4,200 MMBtu/hr)	**Control Method:** Low Sulfur Fuel and good combustion practices **PM Emission Limit:** 0.0034 lb/MMBtu hourly 123.0 tons/year **$PM_{10}/PM_{2.5}$Emission Limit:** 0.0060 lb/MMBtu hourly
Cogen Tech Linden Venture LP	41809 / BOP170001 (7/30/2019)	NJ-0088	250 MW Combined Cycle Combustion Turbine (2,517 MMBtu/hr)	**Control Method:** Use of clean natural gas and ULSD clean burning fuels **PM Emission Limit:** 9.3 lb/hr *(converts to 0.0037 lb/MMBtu)* **$PM_{10}/PM_{2.5}$ Emission Limit:** 11.58 lb/hr *(converts to 0.0046 lb/MMBtu)*
Chickahominy Power LLC	52610-1 (6/24/2019)	VA-0332	Combustion Turbine (4,066 MMBtu/hr)	**Control Method:** Good combustion practices and the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 scf **$PM/PM_{10}/PM_{2.5}$ Emission Limit 1:** 0.0052 lb/MMBtu **$PM_{10}/PM_{2.5}$ Emission Limit 2:** 12.3 lb/hr 53.9 tons/yr
Consumers Energy Company / Jackson Generating Station	118-18 (4/02/2019)	MI-0439	Combined-cycle Turbine (420 MW)	**Control Method:** Combustion inlet air filters, good combustion practices, only combust natural gas **$PM_{10}/PM_{2.5}$ Emission Limit:** 4.9 lb/hr (0.0078 lb/MMBtu)
Jackson Generation, LLC Jackson Energy Center	17040013 (12/31/2018)	IL-0130	Combined-cycle Turbine (3,864 MMBtu/hr)	**Control Method:** Good combustion practices **PM Emission Limit:** 0.0026 lb/MMBtu **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.0042 lb/MMBtu **PM Emission Limit for SU/SD:** 12.3 lb/hr with duct burner 11.5 lb/hr without duct burner **$PM_{10}/PM_{2.5}$ Emission Limit for SU/SD:** 19.8 lb/hr with duct burner 12.4 lb/hr without duct burner
ESC Brooke County Power I, LLC Brooke County Power Plant	R14-0035 (9/18/2018)	WV-0032	Combined-cycle / GE 7HA.01 Turbine (2,737.7 MMBtu/hr)	**Control Method:** Air filter, use of natural gas, and good combustion practices **$PM_{2.5}$ Emission Limits:** 16.9 lb/hr 0.008 lb/MMBtu
APV Renaissance Partners Renaissance Energy Center	30-00235A (08/27/2018)	PA-0319	Combustion Turbine (2,665.9 MMBtu/hr)	**Control Method:** None **$PM/PM_{10}/PM_{2.5}$ Emission Limits:** 0.0043 lb/MMBtu w/o duct burners 121.72 tons/yr w/o duct burners

Facility	Permit Number & Date	RBLC ID #	Emission Unit	PM/PM_{10}/$PM_{2.5}$ Requirements
CPV Three Rivers, LLC	16060032 (07/30/2018)	IL-0129	Combined-cycle Turbine (3,474 MMBtu/hr)	**Control Method:** Good combustion practices **PM Emission Limit:** 0.0037 lb/MMBtu (natural gas) Without duct burner: 8.6 lb/hr With duct burner: 14.4 lb/hr **PM_{10}/$PM_{2.5}$Emission Limit:** 0.0069 lb/MMBtu (natural gas) With duct burner: 18.9 lb/hr Without duct burner: 11.5 lb/hr
DTE Electric Company / Belle River Combined Cycle Power Plant	19-18 (07/16/2018)	MI-0435	Two (2) Combined-Cycle Natural Gas-Fired Combustion Turbine Generators with HRSGs (3,658 MMBtu/hr, each)	**Control Method:** Good combustion practices, inlet air conditioning, use of pipeline quality natural gas **PM/PM_{10}/$PM_{2.5}$ Emission Limit:** 16.0 lb/hour, with duct burner *(converts to 0.0044 lb/MMBtu)* 12.2 lb/hr, without duct burner *(converts to 0.0033 lb/MMBtu)*
Novi Energy	52588 (04/26/2018)	VA-0328	GE Combustion Turbine (3,482 MMBtu/hr)	**Control Method:** Good combustion practices, use of pipeline-quality natural gas **PM_{10}/$PM_{2.5}$Emission Limit:** 0.0069 lb/MMBtu (12.2 lb/hr) w/o duct burner 0.0049 lb/MMBtu (17.3 lb/hr) with duct burner
			Siemens Combustion Turbine (3,116 MMBtu/hr)	**Control Method:** Good combustion practices, use of pipeline-quality natural gas **PM_{10}/$PM_{2.5}$Emission Limit:** 0.0065 lb/MMBtu (13.7 lb/hr) w/o duct burner 0.0065 lb/MMBtu (24.2 lb/hr) with duct burner
Palmdale Energy, LLC	SE 17-01 (04/25/2018)	CA-1251	Combustion Turbine (2,217 MMBtu/hr)	**Control Method:** Clean Fuel, good combustion practices **PM/PM_{10}/$PM_{2.5}$ Emission Limit:** 0.0048 lb/MMBtu (11.8 lb/hr)
Harrison Power	P0122266 (04/19/2018)	OH-0377	MHPS Combustion Turbine (3,231 MMBtu/hr)	**Control Method:** Good combustion practices **PM/PM_{10}/$PM_{2.5}$ Emission Limit:** 0.005 lb/MMBtu (17.7 lb/hr) with duct burner 0.00444 lb/MMBtu (14.1 lb/hr) without duct burner 77.5 tons/yr for all operating modes
			GE model 7HA.02 Combustion Turbine (3,459.6 MMBtu/hr)	**Control Method:** Good combustion practices **PM/PM_{10}/$PM_{2.5}$ Emission Limit:** 0.0052 lb/MMBtu (18.4 lb/hr) with duct burner 0.00735 lb/MMBtu (12.0 lb/hr) without duct burner 80.2 tons/yr for all operating modes.
Harrison County Power Plant	R14-0036 (03/21/2018)	WV-0029	GE 7HA.02 Turbine (3,496.20 MMBtu/hr)	**Control Method:** Air filter, use of natural gas, good combustion practices **PM Emission Limits:** 18.2 lb/hr *(converts to 0.0052 lb/MMBtu)* 100.1 ton/yr
Tennessee Valley Authority - Johnsonville Cogeneration	972969 02/01/2018	TN-0164	Dual Fuel Combustion Turbine and HRSG with duct burner (1,020 MMBtu/hr)	**Control Method:** Good combustion design & practice **PM Emission Limit:** 0.0050 lb/MMBtu (natural gas)
Long Ridge Energy Generation LLC - Hannibal Power	P0122829 (11/07/2017)	OH-0375	General Electric Combustion Turbine (3,544 MMBtu/hr)	**Control Method:** none **PM/PM_{10}/$PM_{2.5}$ Emission Limit:** 0.0036 lb/MMBtu

Facility	Permit Number & Date	RBLC ID #	Emission Unit	$PM/PM_{10}/PM_{2.5}$ Requirements
				12.1 lb/hr excluding SU/SD 53.0 tons/yr including SU/SD
			Siemens Combustion Turbine (3,602 MMBtu/hr)	**Control Method:** none **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.0057 lb/MMBtu (19.8 lb/hr) with duct burner excluding SU/SD 0.006 lb/MMBtu (13 lb/hr) without duct burner excluding SU/SD 86.7 tons/yr for all operating modes, including Startup
			Mitsubishi Combustion Turbine (3,544 MMBtu/hr)	**Control Method:** none **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.004 lb/MMBtu (12.6 lb/hr) with duct burner excluding SU/SD 0.0037 lb/MMBtu (12.3 lb/hr) without duct burner excluding SU/SD 55.2 tons/yr for all operating modes, including startup

The results of the search of the RBLC and other available permits for PM, PM_{10}, and $PM_{2.5}$ BACT/LAER precedents are presented in the table above. Based on this search, the use of clean-burning fuels and good combustion practices are the most stringent available technologies for control of combined-cycle CTG $PM_{10}/PM_{2.5}$ emissions. A review of the above table indicates that PM, PM_{10}, and $PM_{2.5}$ emission limits have been expressed either in lb/hr or lb/MMBtu, or in some cases, in both lb/hr and lb/MMBtu. Different emission limits for the same project can also be associated with different CTG manufacturers. This is illustrated by projects that have one set of limits provided by one supplier and another set of limits provided by another supplier.

A review of the permitted $PM/PM_{10}/PM_{2.5}$ emission limits for natural gas-fueled CTGs shows a wide range of values (from 0.002 to 0.008 lb/MMBtu) typically, but not always, with higher rates during duct firing. The most recently permitted facility in Indiana, the Duke Energy Cayuga Station, in Vermillion County, has BACT requirements of combustion of pipeline-quality natural gas and good combustion practices with an emissions limit of 0.004 lb/MMBtu. The most recent BACT determinations for GE H-class turbines have emissions ranging from 0.004 to 0.008 lb/MMBtu, with the MCE I and MCE II facilities being solidly in this range.

The differences in $PM/PM_{10}/PM_{2.5}$ emission limits among various projects appear to be due to different emission guarantee philosophies of the various suppliers and are not believed to be actual differences in the quantity of $PM/PM_{10}/PM_{2.5}$ emissions inherently produced by the type of turbine. The different emission guarantee philosophies are influenced by the overall uncertainties of the $PM/PM_{10}/PM_{2.5}$ test procedures, especially given reported difficulties in achieving test repeatability, and concerns with artifact emissions introduced by the inclusion of condensable particulate emissions in permit limits in the last decade.

MCE I's proposed $PM/PM_{10}/PM_{2.5}$ limit of 0.0058 lb/MMBtu for GE technology is based on the vendor estimate and is on the lower end of the range of the other $PM/PM_{10}/PM_{2.5}$ BACT limits for GE turbines presented in the above table and is generally consistent with the Duke Energy project. MCE I's proposed $PM/PM_{10}/PM_{2.5}$ limit is more stringent than the existing MCE I facility (0.0075 lb/MMBtu) due to a reduction in vendor emissions estimates.

IDEM, OAQ has determined $PM/PM_{10}/PM_{2.5}$ emission limits for natural gas firing of 0.0058 lb/MMBtu (HHV) for the CTG. BACT will be achieved with the most stringent available $PM/PM_{10}/PM_{2.5}$ control technology, which is the firing of pipeline-quality natural gas. The proposed BACT limits are consistent with the range of values found for recent BACT determinations.

Since there are no technically feasible add-on control options for PM/PM_{10}/$PM_{2.5}$, economic, energy, and environmental impacts have not been evaluated.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for PM, PM_{10}, and $PM_{2.5}$ for the combustion turbine generator shall be as follows:

(1) CTG-01 shall combust pipeline-quality natural gas.

(2) PM, PM_{10}, and $PM_{2.5}$ emissions from CTG-01 shall be limited through the use of good combustion practices.

(3) PM emissions from CTG-01 shall not exceed 0.0058 lb/MMBtu, excluding periods of startup and shutdown.

(4) PM_{10} emissions from CTG-01 shall not exceed 0.0058 lb/MMBtu, excluding periods of startup and shutdown.

(5) $PM_{2.5}$ emissions from CTG-01 shall not exceed 0.0058 lb/MMBtu, excluding periods of startup and shutdown.

Startup and Shutdown Limitations:

(1) The PM, PM_{10}, and $PM_{2.5}$ emissions from the combined cycle combustion turbine stack shall each not exceed 1.9 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

NOx BACT Determination: Combined-Cycle Gas Turbine

In combustion turbine generators (CTGs), NO_X is formed during the combustion of fuel and is generally classified as either thermal NO_X or fuel related NO_X. Thermal NO_X results when atmospheric nitrogen is oxidized at high temperatures to produce nitric oxide (NO), nitrogen dioxide (NO_2), and other oxides of nitrogen. The major factors influencing the formation of thermal NO_X are peak flame temperatures, availability of oxygen at peak flame temperatures, and residence time within the combustion zone. Fuel-related NO_X is formed from the oxidation of chemically bound nitrogen in the fuel. Fuel-related NO_X is generally minimal for natural gas combustion. As such, NO_X formation from combustion of natural gas is due mostly to thermal NO_X formation.

Reduction in NO_X formation can be achieved using combustion controls. Modern CTGs generally use lean pre-mix dry-low-NO_X (DLN) combustors for natural gas firing. In these types of combustors, natural gas and air are pre-mixed prior to combustion, which limits the formation of NO_X by lowering peak flame temperatures. Using this approach, DLN combustors are designed to operate below the stoichiometric ratio, thereby reducing the thermal NO_X formation within the combustion chamber.

Startup/Shutdown
Startup and shutdown events may result in temporarily elevated NOx emissions inherent to the diffusion flame startup mode of the combustion turbines. Combustion turbines default to the

diffusion flame and pilot mode when operating outside of their continuous, stable operation mode. Water injection is not feasible during these times, resulting in higher NOx concentrations.

In the following sections, a top-down BACT analysis is presented for NOx emission sources.

Step One: Identify All Potentially Available Control Technologies

Based on the information reviewed for this BACT determination, the following potentially available control technologies were identified for controlling NOx emissions from the combined cycle gas turbine:

(a) Add-on Control Devices:

(1) Selective Catalytic Reduction (SCR):

The primary post-combustion NO_X control method in use today is selective catalytic reduction (SCR). SCR injects a reagent, either ammonia (NH_3) or urea, into the flue gas downstream of the combustion unit, which reacts with NO_X in the presence of a catalyst to produce nitrogen (N_2) and water vapor. The NO_X reduction reaction is effective only within a given temperature range. The use of a catalyst lowers the temperature range required to maximize the NO_X reduction reaction. For the majority of commercial catalysts, the optimum temperatures for the SCR process range from 480 deg to 400 deg F. The selection of a catalyst is also critical to the operation and performance of the SCR system.

SCR systems are expensive and can significantly impact the feasibility of a project using smaller gas turbines. SCR units are also subject to ammonia "slip," where unreacted ammonia escapes the process and create nuisance problems. Ammonia "slip" will react with sulfides in the exhaust gas stream resulting in condensable particulate.

(2) Selective Non-catalytic Reduction (SNCR):

Like SCRs, SNCR reduces NO_X to nitrogen and water, without using a catalyst. It injects a nitrogenous reducing agent, usually ammonia or urea. A high temperature of 1,600 to 2,100 deg F is required for the reduction to occur. The hardware associated with a SNCR installation is relatively simple and readily available. Typically, SNCR applications tend to have low capital costs compared to SCR, and also require minimum downtime. Though simple in concept, it is challenging in practice to design an SNCR that is reliable, economical, and simple to control, and meets other technical, environmental, and regulatory criteria. Practical application of SNCR is limited by the turbine design and operating conditions.

(3) Water or Steam Injection:

Water or steam injection has been historically used for both natural gas- and oil-fired turbines. The injected water or steam acts as a heat sink to limit peak flame temperatures and minimize NO_X formation. However, new CTGs generally only use water or steam injection for liquid fuel firing.

(4) EMx™:

This is an oxidation/absorption technology using hydrogen (H_2) or methane (CH_4) as a reactant.

(b) Combustion Controls:

(1) Dry-Low-NO_X (DLN) Combustion:

CTG vendors offer what is known as lean pre-mix DLN combustors for natural gas firing, which limits NO_X formation by reducing peak flame temperatures in the combustion zone, and the control of the oxygen availability in the peak temperature zone of the flame. DLN combustors are able to lower NO_X emissions to as low as 5 ppm. DLN technology eliminates the necessity of costly diluent injection and the adverse effects of ammonia utilization. DLN combustion is generally used in combination with SCR.

(c) Good Combustion Practices:

NO_X is one of the primary pollutants created by natural gas combustion in a combined-cycle combustion turbine. Emissions from combustion turbines are highly dependent on the operating load on the turbine. Turbines are designed to achieve maximum efficiency at peak load and controlling emissions over all loads levels is extremely difficult.

(1) Fuel Specification:

Selection of a fuel with negligible amounts of nitrogen will reduce fuel-bound NO_X and will result in modest reductions in NO_X emissions. Selection of a clean burning fossil fuel such as natural gas will minimize fuel-bound NO_X.

(2) Startup/Shutdown:

The potential control methods during startup and shutdown events include the following:

(A) Limit the number of startup and shutdown events per year.
(B) Limit the duration of individual startup and shutdown events.
(C) Limit the annual emissions during startup events.

Step Two: Eliminate Technically Infeasible Control Options

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined the feasibility of the following control devices for this source:

(a) Add-on Control Devices:

(1) Selective Catalytic Reduction (SCR):

SCR control technology can be applied to gas turbines. SCRs are capable of achieving high reduction efficiencies (>70%) on NO_X concentrations as low as 20 ppm. Higher NO_X levels result in increased performance up to about 150 ppm. SCRs have been used in combustion turbines at other permitted facilities and are determined to be a technically feasible control option.

(2) Selective Non-catalytic Reduction (SNCR) and EMx™:

SNCR and EMx™ have never been applied to a combined-cycle combustion turbine due to the lack of physical residence time, turbulence, and temperature for the technology to work. SNCR and EMx™ were determined to be not technically feasible and unable to achieve further reductions than the NO_X reduction achieved by SCR.

(3) Water or Steam Injection:

Water and steam injection cannot be used with DLN combustion. As DLN combustion is more effective than water or steam injection at limiting NO_X formation, DLN combustors were selected as the most effective control option.

(b) Combustion Controls:

(1) Dry-Low-NO_X (DLN) Combustion:

DLN combustion has been used in combined-cycle combustion turbines, and is a feasible control option.

(c) Good Combustion Practices:

(1) Startup/Shutdown:

The combustion turbines at this source are used as peaking units, which necessitates a significant number of startup/shutdown events. The turbines need to be capable of operating when needed and limitations on these events will hamper the intended use of these units. Therefore, limiting the number of startup/shutdown events is not a feasible option.

The duration of startup events is pre-defined by the vendor, is pre-programmed into the automated control systems, and cannot be altered. A limitation on the duration of the startup event is therefore not a feasible option.

A limitation on the total hours of startup/shutdown events, which involves a combination of the number and duration of startup events to reduce NOx emissions, has been determined to be technically feasible.

IDEM has determined that no specific control technologies are feasible for startup and shutdown events. Water injections to reduce the combustion zone temperature is not possible at these times.

Step Three: Rank Remaining Control Technologies by Control Effectiveness

The remaining technically feasible options for controlling NOx emissions from the source are as follows (listed in descending order of most technically feasible):

Table 1. Control Technology Rankings for NOx

Technology	Control Efficiency %	Control Level for BACT Analysis
SCR	70% to 90%	90%
Good Combustion Practices	<80%	80%
DLN	64%	64%

Step Four: 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) under Process Type Code 15.210 (Large Combustion Turbines - Natural Gas), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Summary of RBLC Database Review - Large Combustion Turbines - Natural Gas

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Requirements
Maple Creek Energy I LLC	Proposed	--	Combined Cycle Combustion Turbine Generator (4,253 MMBtu/hr)	**Control Method:** Selective Catalytic Reduction system and dry-low NOx combustors, good combustion practices **NO_X Emission Limits:** 2.0 ppmvdc, excluding SU/SD @ 15% O_2 based on a 3-hour average 30.9 lb/hr, excluding SU/SD **NOx SU/SD Emission Limit:** 35.8 tons/yr for duration of combined SU/SD Events
Maple Creek Energy I LLC	T153-45909-00056 (06/19/2023)	IN-0365	Combined Cycle Combustion Turbine (4,200 MMBtu/hr)	**Control Method:** SCR with DLN combustion **NO_X Emission Limits:** 2.0 ppmvd at 15% O_2 (3-hr avg) 0.0073 lb/MMBtu **NOx SU/SD Emission Limit:** 35.8 tons/yr for duration of combined SU/SD Events
Maple Creek Energy II LLC	Proposed	--	Combined Cycle Combustion Turbine Generator (4,253 MMBtu/hr)	**Control Method:** Selective Catalytic Reduction system and dry-low NOx combustors, good combustion practices **NO_X Emission Limits:** 2.0 ppmvdc, excluding SU/SD @ 15% O_2 based on a 3-hour average 30.9 lb/hr, excluding SU/SD **NOx SU/SD Emission Limit:** 35.8 tons/yr for duration of combined SU/SD Events
Golden Spread Electric Cooperative, Inc.	109148, PSD1358M2, GHG41M2 (08/14/25)	TX-1000	Simple-Cycle Turbine (2,033 MMBtu/hr)	**Control Method:** Dry Low NOx burner and firing pipeline-quality natural gas, minimizing the duration of MSS activities and operating the facility in accordance with best management practices and good air pollution control practices. **NOx Emission Limits:** 9.0 ppmvd, 15% O_2
Duke Energy, Indiana, Inc. - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	Two (2) Combustion Turbines (4,254 MMBtu/hr)	**No NOx Emission Limit**
Wabash Valley Resources, LLC	167-45208-00091 (01/11/2024)	IN-0371	Integrated Gasification Combined Cycle Combustion Turbine (2,292 MMBtu/hr)	**Control Method:** Steam Injection/SCR and Good Combustion Practices **NO_X Emission Limits:** 2.0 ppmv at 15% O_2 when combusting 50% natural gas 16.5 lb/hr when combusting 50% natural gas **Pollutant Notes:** NO_X emissions shall not exceed 8 ppmv @ 15% O_2 and 52.0 lb/hr when combusting greater than 50% hydrogen.
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Combustion Turbine (4,671 MMBtu/hr)	**Control Method:** (Except during SU/SD) SCR, low-NO_X burners, and water injection when firing diesel fuel. **NO_X Emission Limit 1:** 2.0 ppm 24-Hour Rolling Average, firing natural gas
Entergy Texas, Inc. - Orange County Advanced Power	166032 PSDTX1598 GHGPSDTX210	TX-0939	Combined Cycle Turbines (1,215 MW and 6,762	**No NOx Emission Limit**

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Requirements
Station	(03/13/2023)		Btu/hr)	
Midland Cogeneration Venture Limited Partnership	10-23 (02/01/2023)	MI-0455	EUCTGHRSG1 (4,197.60 MMBtu/hr)	**Control Method:** Selective Catalytic Regeneration **NO_X Emission Limits:** 2.0 ppm ppmdv at 15% O_2 (24-hr rolling average, except SU/SD) **NO_X Emission Limit 2:** 39.6 lb/hr, except SU/SD **NO_X Emission Limit 3:** 15 ppmvd at 15% O_2 (4-hr rolling average, except during operations less than 75% of peak load) **NO_X SU/SD Emission Limit:** 851.2 lb/hr during SU/SD
Lansing Board of Water and Light - Erickson Station	74-18D (12/20/2022)	MI-0454	EUCTGHRSG1 and EUCTGHRSG2 (667 MMBtu/hr, each)	**Control Method:** Dry low NO_X burners and SCR, for each CTG/HRSG unit **NO_X Emission Limit 1 (for each):** 3.0 ppm ppmdv at 15% O_2 (24-hr rolling average, excluding SU/SD) **NO_X Emission Limit 2 (for each):** 60.0 lb/hr, including SU/SD in combined cycle mode **NO_X Emission Limit 3 (for each):** 60.0 lb/hr (24-hr rolling average, as determined each operating hour, including in HRSG bypass mode.) **NO_X Emission Limit 4 (for each):** 25 ppmvd at 15% O_2 (4-hr rolling average except during operation less than 75% of peak load, applies to bypass mode.) **NO_X Emission Limit 5 (for each):** 25 ppmvd at 15% O_2 (30-day rolling average except during operation less than 75% of peak load, applies to combined cycle mode.)
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	Combined Cycle Combustion Turbine (3,647 MMBtu/hr)	**Control Method:** Dry low-NO_X combustion with ultra-low NO_X combustors; low-NO_X duct burners; and selective catalytic reduction (SCR) **NOx Emission Limit:** 2.0 ppmv @ 15% O_2, (3-hr rolling avg) except SU/SD (*no lb/MMBtu listed)* **NOx SU/SD Emission Limit:** 130 lb/hr (cold start/shakedown) 71 lb/hr (non-cold start) 55 lb/hr (shutdown)
Alaska Gasline Development Corporation Liquefaction Plant	AQ1539CPT01 (07/07/2022)	AK-0088	(4) Combined Cycle Gas-Fired Turbines (384 MMBtu/hr, each)	**Control Method:** SCR, DLN combustors, and good combustion practices **NOx Emission Limit:** 2.0 ppmv at 15% O_2 3-hour rolling average Allowed 40 hours per year per turbine of operation without SCR and OxCat
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Combined Cycle Natural Gas-Fired Combustion Turbine Generator with HRSG (3,064 MMBtu/hr)	**Control Method:** SCR with DLNB **NOx Emission Limits:** 2.5 ppm 24-hour rolling average, except SU/SD 29.2 lb/hr 24-hr rolling average, except SU/SD 15 ppmvd @ 15% O2 30-day rolling average, except SU/SD **NOx SU/SD Emission Limit:** 126.5 lb/hr during SU/SD SU/SD are limited to 300 hours per 12 month rolling period
Marshall Energy Center, LLC -	168-17B (06/03/2022)	MI-0452	Combined Cycle Natural Gas-Fired	**Control Method:** SCR with DLNB

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Requirements
MEC South, LLC			Combustion Turbine Generator with HRSG (3,064 MMBtu/hr)	**NOx Emission Limits:** 2.0 ppm 24-hour rolling average, except SU/SD 29.2 lb/hr 24-hr rolling average, except SU/SD 15 ppmvd @ 15% O_2 30-day rolling average, except SU/SD **NOx SU/SD Emission Limit:** 126.5 lb/hr during SU/SD SU/SD are limited to 300 hours per 12 month rolling period
Magnolia Power LLC- Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Combined Cycle Gas Turbine (5,081 MMBtu/hr)	**Control Method:** Dry low-NO_X combustor design, SCR, and good combustion practices **NOx Emission Limits:** 2.0 ppmvd @ 15% O_2 on a 24-hour rolling average, except SU/SD **NOx SU/SD Emission Limit:** 260.0 lb/hr during SU/SD
Mountain State Clean Energy LLC Maidsville	R14-0038 (01/05/2022)	WV-0033	Combustion Turbine and Duct Burner (1,275 MW)	**Control Method:** SCR, dry low NOx burners **NOx Emission Limits:** 2.0 ppmvd at 15% O_2 3-hour rolling average 32.09 lb/hr excluding SU/SD 0.43 lb/MW-H gross 30 operating day rolling avg. excluding SU/SD.
Shady Hills Energy Center, LLC	1010524-003-AC / PSD-FL-444A (06/07/2021)	FL-0371	Combustion Turbine and HRSG with Duct Firing (3,622 MMBtu/hr)	**Control Method:** Dry low-NOX combustors and Selective Catalytic Reduction (SCR) **NOx Emission Limits:** 2.0 ppmvd @ 15% O_2 24-hour block average basis 15.0 ppmvd at 15% O_2 (for turbine loads >=75%) 30-operating-day rolling avg. 96.0 ppmvd at 15% O_2 (for turbine loads <75%) 30-operating-day rolling avg.
Renovo Energy Center LLC / Renovo PLT	18-00033B (04/29/2021)	PA-0334	Combustion Turbines with Duct Burners #1 and #2 (4,546 MMBtu/hr, each)	**Control Method:** Selective Catalytic Reduction (SCR) and oxidation catalyst **NOx Emission Limits:** 2.0 ppmvd @ 15% O_2 / 1 hr 33.3 lb/hr
Virginia Electric and Power Company	52404-5 (12/01/2020)	VA-0334	Three (3) Combustion Turbine Generators (3,442 MMBtu/hr, each)	**Control Method:** Dry, low NOx burners and selective catalytic reduction (SCR) **NOx Emission Limits:** 2.0 ppmv at 15% O_2 604 lb/day per turbine
Alabama Power Company - Plant Barry	503-1001 (11/09/2020)	AL-0328	Two (2) Combined Cycle Units (744 MW, each)	**Control Method:** Selective Catalytic Reduction (SCR) **NOx Emission Limits:** 2.0 ppmv at 15% O_2 39.1 lb/hr 3-hour avg.
FG LA Complex	PSD-LA-812 (01/06/2020)	LA-0364	Natural Gas Cogeneration Units (2,222 MMbtu/hr)	**Control Method:** Dry low NOx combustor design, SCR **NOx Emission Limit:** 2.0 ppm ppmvd @15% O_2, 12-Month Rolling Avg.
Indeck Niles, LLC	75-16B (11/26/2019)	MI-0445	Natural Gas Combined-cycle Turbine (3,421 MMBtu/hr)	**Control Method:** SCR, low NOx burners **NOx Emission Limits:** 2.0 ppm ppmvd @15% O_2, 24-hr roll avg. except SU/SD 15.0 ppm, 30-day roll avg det. each operating day 27.4 lb/hr, 24-hour rolling avg. except SU/SD **NOx SU/SD Emission Limits:** 286 lb/hr, during startup or shutdown

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Requirements
				SU/SD operations are limited to 500 hours per 12-month rolling time period
Thomas Township Energy, LLC	210-18 (8/21/2019)	MI-0442	Natural Gas Combined-cycle Turbine (625 MW, 4,200 MMBtu/hr)	**Control Method:** SCR, low NOx burners, good combustion practices **NOx Emission Limits:** 2.0 ppmvd 24hr roll avg except during SU/SD 15 ppmvd, based on a 30-day rolling average, except during operation less than 75 percent of peak load. **NOx SU/SD Emission Limit:** 190 lb/hr, including SU/SD
ESC Tioga County Power LLC / Electric Power Generation Facility	59-00034A (08/20/2019)	PA-0333	Combustion Turbine / Duct Burner (4,469 MMBtu/hr)	**Control Method:** SCR, catalytic oxidizer **NOx Emission Limits:** 2.0 ppmvd @ 15% O_2, 1-hr 143.2 tons per twelve (12) consecutive month period
Cogen Tech Linden Venture LP	41809 / BOP170001 (7/30/2019)	NJ-0088	250 MW Combined Cycle Combustion Turbine (2,517 MMBtu/hr)	**Control Method:** SCR, low NOx burners, NG as primary fuel **NOx Emission Limits:** 18.30 lb/hr 2.00 ppmvd@15% O_2 3 h rolling avg.
Chickahominy Power LLC	52610-1 (6/24/2019)	VA-0332	Combustion Turbine (4,066 MMBtu/hr)	**Control Method:** SCR, dry-low NOx burners **NOx Emission Limits:** 2.00 ppmvd, 15% O_2 1-hr avg, except SU/SD 128.4 tons/year, 12-mo rolling average **NOx SU/SD Emission Limit:** 60 lbs/event cold start (42 minutes or less) 42 lb/event hot start (42 minutes or less) 20 lb/event shut down - (15 minutes or less) 703.0 lb/cal. day 24 hr total. This limit applies during tuning (limited to 18 hours/event).
Consumers Energy Company / Jackson Generating Station	118-18 (4/02/2019)	MI-0439	Combined-cycle Turbine (420 MW)	**Control Method:** Steam Injection, good combustion practices, only combust natural gas **NOx Emission Limit 1:** 25.0 ppm at 15% O_2 during periods with no duct firing; 30-day rolling avg except during SU/SD; Each unit **NOx Emission Limit 2:** 22.0 ppm at 15% O_2; 30-day rolling avg; all units combined **NOx Emission Limit 3:** 54.0 lb/hr (equates to approximately 0.09 lb/MMBTU) when the turbine operates alone and when the turbine operates in conjunction with its respective duct burner on a 30-day rolling average as determined at the end of each calendar day. These limits apply during periods of SU/SD.
Jackson Generation, LLC Jackson Energy Center	17040013 (12/31/2018)	IL-0130	Combined-cycle Turbine (3,864 MMBtu/hr)	**Control Method:** SCR, dry low-NOx combustion technology **NOx Emission Limit 1:** 2.0 ppmv at 15% O_2/3 hr (first 36 months of operation) 2.0 ppmv at 15% O_2/1 hr (36 months after commissioning of turbines) <u>Without duct burner:</u> 30.5 lb/hr (normal operation) without duct burner 180.3 lb/hr (startup/shutdown/commissioning) 91.5 lb/hr (tuning) <u>With duct burner:</u> 33.9 lb/hr (normal operation 33.9 lb/hr (startup/shutdown/commissioning) 91.5 lb/hr (tuning)
ESC Brooke County Power I,	R14-0035 (9/18/2018)	WV-0032	Combined Cycle / GE 7HA.01 Turbine	**Control Method:** SCR, dry-low NOx burners

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Requirements
LLC Brooke County Power Plant			(462.5 MW, 2,737.7 MMBtu/hr)	**NOx Emission Limit:** 2.0 ppm 23.2 lb/hr
APV Renaissance Partners Renaissance Energy Center	30-00235A (08/27/2018)	PA-0319	Combustion Turbine (2,665.9 MMBtu/hr)	**Control Method:** SCR **NOx Emission Limits:** 2.0 ppmdv @ 15% O_2 222.74 tons/yr
CPV Three Rivers, LLC	16060032 (07/30/2018)	IL-0129	Combined-cycle Turbine (3,474 MMBtu/hr)	**Control Method:** SCR, low NOx burners **NOx Emission Limit:** 2.0 ppmv at 15% O_2 / 3-hr, except SU/SD Permit limits are as follows, applicable on a per-turbine basis, 3-hr average for natural gas: Without duct burner: 25.2 lb/hr With duct burner: 32.0 lb/hr Other periods (incl. startup/shutdown): 228 lb/hr Extended startup: 228 lb/hr Tuning: 228 lb/hr
DTE Electric Company / Belle River Combined Cycle Power Plant	19-18 (07/16/2018)	MI-0435	Two (2) Combined-Cycle Natural Gas-Fired Combustion Turbine Generators with HRSGs (3,658 MMBtu/hr, each)	**Control Method:** Selective catalytic reduction with dry low NOx burners **NOx Emission Limit:** 2.0 ppmvd @ 15% O_2, 24-hr rolling avg., each unit, except SU/SD 28.9 lb/hr, each unit, except SU/SD 15 ppmvd @ 15% O2, 30-day rolling avg., each unit **NOx SU/SD Emission Limit:** 262.4 lb/hr, each unit, during SU/SD
Novi Energy	52588 (04/26/2018)	VA-0328	GE Combustion Turbine (3,482 MMBtu/hr)	**Control Method:** SCR, low NOx burners **NOx Emission Limits:** 2.0 ppmvd at 15% O_2 1-hour avg., except SU/SD startup/shutdown 141.3 tons/yr 12-month rolling total; except SU/SD **NOx SU/SD Emission Limit:** 273 lb/turbine/event cold start (60 min or less) 163 lb/turbine/event warm start (50 min or less) 105 lb/turbine/event hot start (30 min or less) 18 lb/turbine/event shutdown (30 min or less)
			Siemens Combustion Turbine (3,116 MMBtu/hr)	**Control Method:** SCR, low NOx burners **NOx Emission Limits:** 2.0 ppmvd at 15% O_2 1-hour avg., except SU/SD 141.4 tons/yr 12-month rolling total, except SU/SD **NOx SU/SD Emission Limit:** 95 lb/turbine/event cold start (55 min or less) 117 lb/turbine/event warm start (55 min or less) 8 lb/turbine/event hot start (50 min or less) 51 lb/turbine/event shutdown (38 min or less)
Palmdale Energy, LLC	SE 17-01 (04/25/2018)	CA-1251	Combustion Turbine (2,217 MMBtu/hr)	**Control Method:** SCR, low NOx burners **NOx Emission Limit:** 2.0 ppmvd at 15% O_2 1-hour avg., not startup/shutdown 18.5 lb/hr with duct burner (1-hr average) 17.1 lb/hr without duct burner (1-hr average) **NOx SU/SD Emission Limits:** Cold Start: 51.5 lb/event, 39 minutes Warm Start: 46.8 lb/event, 35 minutes Hot Start: 43.2 lb/event, 30 minutes Shutdown: 33.0 lb/event, 25 minutes Startup/Shutdown: 53.6 lb/hr (1-hr average)
Harrison Power	P0122266 (04/19/2018)	OH-0377	MHPS Combustion Turbine	**Control Method:** SCR, low NOx burners

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Requirements
			(3,231 MMBtu/hr)	**NOx Emission Limit:** 2.0 ppmvd at 15% O_2 24-hour block avg. period. 28.0 lb/hr with duct burner except SU/SD 26.7 lb/hr without duct burner except SU/SD. 124 tons per rolling 12-month period for all operating modes including SU/SD **NOx SU/SD Emission Limits:** 3.22 tons per rolling 12-month period for SU/SD
			GE model 7HA.02 Combustion Turbine (3,459.6 MMBtu/hr)	**Control Method:** SCR, low NOx burners **NOx Emission Limit:** 2.0 ppmvd at 15% O_2 24-hour block avg. period. 29.5 lb/hr with duct burner except SU/SD 25.1 lb/hr without duct burner except SU/SD. 139 tons per rolling 12-month period for all operating modes including SU/SD. **NOx SU/SD Emission Limits:** 12.99 tons per rolling 12-month period for SU/SD.
Harrison County Power Plant	R14-0036 (03/21/2018)	WV-0029	GE 7HA.02 Turbine (3496.20 MMBtu/hr)	**Control Method:** SCR, dry-low NOx burners **NOx Emission Limits:** 2.0 ppm 32.9 lb/hr 1-hr avg. 156.2 tons/year, 12-mo rolling average
Tennessee Valley Authority - Johnsonville Cogeneration	972969 02/01/2018	TN-0164	Dual Fuel Combustion Turbine and HRSG with duct burner (1,020 MMBtu/hr)	**Control Method:** SCR, good combustion design & practices **NOx Emission Limits (Natural Gas):** 2.0 ppmvd @ 15% O_2 / 30-day avg., except SU/SD
Long Ridge Energy Generation LLC - Hannibal Power	P0122829 (11/07/2017)	OH-0375	General Electric Combustion Turbine (3,544 MMBtu/hr)	**Control Method:** SCR, low NOx burners **NOx Emission Limits:** 2.0 ppmvd at 15% O_2 24-hour block avg. period. 26.1 lb/hr, except SU/SD 125.8 tons of NOx per rolling 12-month period including SU/SD **NOx SU/SD Emission Limits:** 164.5 lb/hr during cold startup 109.7 lb/hr during hot startup 87.4 lb/hr during warm startup, 27.9 lb/hr during shutdown.
			Siemens Combustion Turbine (3,602 MMBtu/hr)	**Control Method:** SCR, low NOx burners **NOx Emission Limits:** 2.0 ppmvd at 15% O_2 24-hour block avg. period. 27.1 lb/hr with duct burner excluding SU/SD 22.4 lb/hr without duct burner excluding SU/SD 128.8 tons of NOx per rolling 12-month period including SU/SD **NOx SU/SD Emission Limits:** 72.7 lb/hr during cold startup. 77.7 lb/hr during hot startup, 87.1 lb/h during warm startup, 44.8 lb/h during shutdown.
			Mitsubishi Combustion Turbine (3,544 MMBtu/hr)	**Control Method:** SCR, low NOx burners **NOx Emission Limit:** 2.0 ppmvd at 15% O_2. 25.1 lb/hr with duct burner, except SU/SD 26.4 lb/hr without duct burner, except SU/SD 119.4 tons per rolling 12-month period including SU/SD **NOx SU/SD Emission Limits:** 68.1 lb/hr during cold startup 34.6 lb/hr during hot startup

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Requirements
				55.4 lb/h during warm startup 37.9 lb/h during shutdown.

The results of the search of the RBLC and other available permits for NOx BACT/LAER precedents are presented in the table above. A review of the above table indicates that BACT emission limits for NOx are equivalent to or higher than the emission limit proposed for this facility. Generally, the natural gas-fired, combined-cycle CTGs permitted at this NOx level use dry-low-NOx combustors, water injection, and SCR systems. Therefore, the most stringent level of NOx control identified for similar, large, combined-cycle CTG projects is SCR, in combination with dry-low-NOx combustors, to achieve 2.0 ppmvdc for natural gas firing.

Step Five: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the combustion turbine generator shall be as follows:

(1) The NOx emissions from CTG-01 shall be controlled by a Selective Catalytic Reduction system, dry-low-NOx combustors, and good combustion practices.

(2) The NOx emissions from CTG-01 shall not exceed 2.0 ppmvd @ 15% O_2 based on a 3-hour average, excluding periods of startup and shutdown.

(3) NOx emissions from CTG-01 shall not exceed 30.9 lb/hr, excluding periods of startup and shutdown.

Startup and Shutdown Limitations:

(1) The NOx emissions from the combined cycle combustion turbine stack shall not exceed 35.8 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

Since the most stringent level of control is being proposed, an economic analysis has not been conducted. Energy-related impacts are directly translatable into economic impacts and similarly have not been examined. One environmental impact that has been identified is the resulting emissions of “ammonia slip” that occur with the use of SCR.

VOC BACT Determination: Combined-Cycle Gas Turbine

Emissions of VOC from a CTG occur as a result of incomplete combustion of the fuel. In an ideal combustion process, all carbon and hydrogen contained within the fuel are oxidized to form CO_2 and water. VOC emissions can be minimized using good combustion practices and add-on controls as described below. CTGs have inherently low VOC emission rates due to very efficient combustion.

Step One: Identify All Potentially Available Control Technologies

Below is the ranking of technically feasible VOC control technologies identified for new large combined-cycle CTGs. The technologies identified below are the only VOC control technologies that have been applied to a natural gas-fired CTG with a generating capacity greater than 100 MW in recent years.

(a) Oxidation Catalyst:

An oxidation catalyst system oxidizes carbon-containing compounds at temperatures present in the HRSG through the use of a catalyst. An oxidation catalyst system is widely recognized as the most stringent available post-combustion control technology for VOC emissions from combined-cycle CTGs.

Oxidation catalyst systems consist of a passive reactor comprised of a grid of metal panels with a platinum catalyst. The optimal location of the catalyst for VOC control is the 900°F to 1,100°F temperature range. However, at the high temperatures necessary to make the oxidation catalyst optimized for VOC reduction, there is the undesirable result of substantially greater conversion of SO_2 to SO_3, which results in increased emissions of H_2SO_4 and/or ammonium salts (PM_{10}/$PM_{2.5}$). Therefore, placement of the oxidation catalyst is most frequently located in a slightly lower temperature section of the HRSG, normally just upstream of the SCR system, to maintain a high efficiency for CO reduction while also reducing VOC emissions.

(b) 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, nevertheless it is also considered as a technology for controlling VOC emissions. 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^{o}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.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is not a technically feasible option for the combined cycle combustion turbines at this source.

(c) 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 the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a recuperative thermal oxidizer is not a technically feasible option for the combined cycle combustion turbines at this source.

(c) 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.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is not a technically feasible option for the combined cycle combustion turbine at this source

(b) Combustion Controls:

CTG vendors have designed lean pre-mix DLN combustors for natural gas firing to provide a high degree of combustion efficiency. Combustion controls are commonly used in combination with an oxidation catalyst to minimize VOC emissions. However, combustion controls alone are less effective than an oxidation catalyst combined with combustion controls.

Step Two: Eliminate Technically Infeasible Control Options

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use regenerative thermal oxidizers, recuperative thermal oxidizers and flares are not technically feasible options for this source for the following reasons as described below. Oxidation catalyst and good combustion control are the only VOC control technologies that have been applied to a natural gas-fired CTG with a generating capacity greater than 100 MW in recent years. Therefore, neither control method has been eliminated due to being technically infeasible.

(a) Oxidation Catalyst:

Oxidation catalysts have been used in combustion turbines at other permitted facilities and are determined to be a technically feasible control option.

(b) Regenerative Thermal Oxidizers

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is not a technically feasible option for the combined cycle combustion turbines at this source.

(c) Recuperative Thermal Oxidizers

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a recuperative thermal oxidizer is not a technically feasible option for the combined cycle combustion turbines at this source.

(c) Flare

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is not a technically feasible option for the combined cycle combustion turbine at this source

(d) Combustion Controls:

Combustion controls and combustion controls used in combination with an oxidation catalyst to minimize VOC emissions are commonly utilized. Therefore, combustion controls are determined to be a technically feasible control option.

Step Three: Rank Remaining Control Technologies by Control Effectiveness

Combustion controls are commonly used in combination with an oxidation catalyst to minimize VOC emissions. However, combustion controls alone are less effective than an oxidation catalyst combined with combustion controls.

Step Four: 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) under Process Type Code 15.210 (Large Combustion Turbines - Natural Gas), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Summary of RBLC Database Review - Large Combustion Turbines - Natural Gas - VOC

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Maple Creek Energy I LLC	Proposed	--	Combined Cycle Combustion Turbine Generator (4,253 MMBtu/hr)	**Control Method:** Catalytic oxidation and good combustion practices **VOC Emission Limit:** 1.0 ppmvd excluding SU/SD 0.0013 lb/MMBtu, excluding SU/SD **VOC SU/SD Limit:** 18.8 tons/year for duration of combined SU/SD
Maple Creek Energy LLC	Existing T153-45909-00056 (06/19/2023)	IN-0365	Combined Cycle Combustion Turbine CTGB (4,200 MMBtu/hr)	**Control Method:** Oxidation Catalyst and GCP **VOC Emission Limit:** 1.0 ppmvd @ 15% O_2 3-hr avg. 0.0013 lb/MMBtu **VOC SU/SD Limit:** 18.8 tons/year for duration of combined SU/SD

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
Maple Creek Energy II LLC	Proposed	--	Combined Cycle Combustion Turbine Generator (4,253 MMBtu/hr)	**Control Method:** Catalytic oxidation and good combustion practices **VOC Emission Limit:** 1.0 ppmvd excluding SU/SD 0.0013 lb/MMBtu, excluding SU/SD **VOC SU/SD Limit:** 18.8 tons/year for duration of combined SU/SD
Golden Spread Electric Cooperative, Inc.	109148, PSD1358M2, GHG41M2 (08/14/25)	TX-1000	Simple-Cycle Turbine (2,033 MMBtu/hr)	**No VOC Emission Limit**
Duke Energy Indiana, Inc. - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	Two (2) Combustion Turbines (4,254 MMBtu/hr, each)	**Control Method:** Oxidation catalyst and good combustion practices **VOC Emission Limit 1:** 1.0 ppmvd @ 15% O_2 3-hr without duct burner firing, excluding SU/SD **VOC Emission Limit 2:** 2.0 ppmvd @ 15% O_2 3-hr with duct burner firing, excluding SU/SD **VOC Emission Limit 3:** 46 tons of VOC per twelve (12) consecutive month period, including SU/SD (per stack)
Wabash Valley Resources, LLC	167-45208-00091 (01/11/2024)	IN-0371	Integrated Gasification Combined Cycle Combustion Turbine (2,292 MMBtu/hr)	**No VOC Emission Limit**
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Combustion Turbine (4,671 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **VOC Emission Limit:** 2.7 ppm @ 15% O2 with duct firing. 0.60 ppm @ 15% O2 without duct firing (*no lb/MMBtu listed)*
Entergy Texas, Inc. Orange County Advanced Power Station	166032 PSDTX1598 GHGPSDTX210 (03/13/2023)	TX-0939	Combined Cycle Turbines (1,215 MW and 6,762 Btu/hr)	**Control Method:** Oxidation Catalyst and GCP **VOC Emission Limit:** 2.0 ppmvd @ 15% O_2 3-hr avg. (*no lb/MMBtu listed)*
Midland Cogeneration Venture Limited Partnership	10-23 (02/01/2023)	MI-0455	EUCTGHRSG1 (4,197.60 MMBtu/hr)	**Control Method:** Oxidation Catalyst and GCP **VOC Emission Limit 1:** 2.4 ppmvd @ 15% O_2 1-hr avg. except SU/SD (*no lb/MMBtu listed)* **VOC Emission Limit 2:** 11.4 lb/hr except SU/SD
Lansing Board of Water and Light - Erickson Station	74-18D (12/20/2022)	MI-0454	EUCTGHRSG1 and EUCTGHRSG2 (667 MMBtu/hr, each)	**Control Method:** Oxidation Catalyst and GCP **VOC Emission Limit 1 (each):** 3.0 ppmvd @ 15% O_2 1-hr avg. except SU/SD, for combined cycle mode (*no lb/MMBtu listed)* **VOC Emission Limit 2:** 5.0 lb/hr except SU/SD except SU/SD, for HRSG bypass mode
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	Combined Cycle Combustion Turbine (3,647 MMBtu/hr)	**Control Method:** Oxidation Catalyst and GCP **VOC Emission Limit 1 (each):** 1.0 ppmv @ 15% O_2 3-hr avg. except SU/SD **VOC Emission Limit 2:** 1.1 ppmv @ 15% O_2 3-hr avg. except SU/SD

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
				(*no lb/MMBtu listed)* **VOC Emission Limit 3:** During each hour that includes a startup or shutdown and shakedown 56 lb/hr cold start 48 lb/hr non-cold start 44 lb/hr shutdown
Alaska Gasline Development Corporation Liquefaction Plant	AQ1539CPT01 (07/07/2022)	AK-0088	(4) Combined Cycle Gas-Fired Turbines (384 MMBtu/hr, each)	**Control Method:** Oxidation Catalyst and GCP **VOC Emission Limit 1 (each):** 2.0 ppmv @ 15% O_2 3-hr avg. (*no lb/MMBtu listed)*
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Combined Cycle Natural Gas-Fired Combustion Turbine Generator with HRSG (3,064 MMBtu/hr)	**Control Method:** Oxidation Catalyst and GCP **VOC Emission Limit:** 2.0 ppmv @ 15% O_2 except SU/SD (*no lb/MMBtu listed)* **SU/SD Limit:** 300 hours per 12 month rolling time period
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/03/2022)	MI-0452	Combined Cycle Natural Gas-Fired Combustion Turbine Generator with HRSG (3,064 MMBtu/hr)	**Control Method:** Oxidation Catalyst and GCP **VOC Emission Limit:** 2.0 ppmv @ 15% O_2 except SU/SD (*no lb/MMBtu listed)* **SU/SD Limit:** 300 hours per 12 month rolling time period
Magnolia Power LLC- Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Combined Cycle Gas Turbine (5,081 MMBtu/hr)	**Control Method:** Oxidation Catalyst and GCP **VOC Emission Limit 1 (each):** 1.0 ppmvd @ 15% O_2 3-hr avg. without duct firing **VOC Emission Limit 2:** 2.0 ppmvd @ 15% O_2 3-hr avg. with duct firing (*no lb/MMBtu listed)* **SU/SD Limit:** 520 lb/hr
Mountain State Clean Energy LLC Maidsville	R14-0038 (01/05/2022)	WV-0033	Combustion Turbine and Duct Burner (1,275 MW)	**Control Method:** Oxidation catalyst and good combustion practices **VOC Emission Limit 1:** 1.0 ppmdv at 15% O2 without duct firing, excluding SU/SD **VOC Emission Limit 2:** 2.0 ppmdv at 15% O2 with duct firing, excluding SU/SD **VOC Emission Limit 3:** 11.19 lb/hr (*no lb/MMBtu listed)*
Renovo Energy Center LLC / Renovo PLT	18-00033B (04/29/2021)	PA-0334	Combustion Turbines with Duct Burners #1 and #2 (4546 MMBtu/hr, each)	**Control Method:** SCR* and catalytic oxidizer **VOC Emission Limits:** 1.6 ppmdv at 15% O2 9.3 lb/hr (*no lb/MMBtu listed)*
Alabama Power Company	503-1001 (11/09/2020)	AL-0328	(2) Combined Cycle Units (744 MW)	**Control Method:** Oxidation Catalyst **VOC Emission Limits:** 13.6 lb/hr 0.003 lb/MMBtu
FG LA Complex	PSD-LA-812 (01/06/2020)	LA-0364	Natural Gas Cogeneration Units (2222 MMbtu/hr)	**Control Method:** Good combustion practices and catalytic oxidation

Facility	**Permit Number & Date**	**RBLC ID #**	**Emission Unit**	**VOC Requirements**
				VOC Emission Limit: 4.0 ppmvd @ 15% O_2 (*no lb/MMBtu listed)*
Indeck Niles, LLC	75-16B (11/26/2019)	MI-0445	Natural Gas Combined Cycle Turbine (3,421 MMBtu/hr)	**Control Method:** Good combustion practices, inlet air conditioning, and the use of pipeline quality natural gas **VOC Emission Limit 1:** 4.0 ppm ppmvd @15% O_2 hourly (each) Except SU/SD. (*no lb/MMBtu listed)* **VOC Emission Limit 2:** SU/SD operations are limited to 500 hrs per yr.
Thomas Township Energy, LLC	210-18 (8/21/2019)	MI-0442	Natural Gas Combined Cycle Turbine (625 MW, 4,200 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **VOC Emission Limits:** 0.0040 lb/MMBtu hourly, without duct firing, except during SU/SD 377 tons/yr (*no lb/MMBtu listed)*
Cogen Tech Linden Venture LP	41809 / BOP170001 (7/30/2019)	NJ-0088	250 MW Combined Cycle Combustion Turbine (2,517 MMBtu/hr)	**Control Method:** Oxidation Catalyst and use of natural gas as primary fuel **VOC Emission Limits:** 3.2 lb/hr 1.0 ppmvd @15% O_2 3 h rolling avg (*no lb/MMBtu listed)*
Chickahominy Power LLC	52610-1 (6/24/2019)	VA-0332	Combustion Turbine (4,066 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **VOC Emission Limits:** 0.70 ppmvd @ 15% O2, without duct firing 68.1 tons/yr (*no lb/MMBtu listed)*
ESC Brooke County Power I, LLC Brooke County Power Plant	R14-0035 (9/18/2018)	WV-0032	Combined Cycle / GE 7HA.01 Turbine (462.5 MW, 2,737.7 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **VOC Emission Limits:** 8.1 lb/hr 2.0 ppm with duct firing 1.0 ppm with no duct firing (*no lb/MMBtu listed)*
APV Renaissance Partners Renaissance Energy Center	30-00235A (08/27/2018)	PA-0319	Combustion Turbine (2,665.9 MMBtu/hr)	**Control Method:** Oxidation Catalyst **VOC Emission Limits:** 1.0 ppmdv @ 15% O_2 without duct burners 1.4 ppmvd @15% O_2 with duct burners 55.24 tons/yr without duct burners (*no lb/MMBtu listed)*
DTE Electric Company / Belle River Combined Cycle Power Plant	19-18 (07/16/2018)	MI-0435	Two (2) Combined Cycle Natural Gas-Fired Combustion Turbine Generators with HRSGs (3,658 MMBtu/hr, each)	**Control Method:** Oxidation catalyst and good combustion practices **VOC Emission Limit:** 0.0026 lb/MMBtu, each unit, except SU/SD 0.0013 lb/MMBtu, each unit, without duct burner, except SU/SD
Novi Energy	52588 (04/26/2018)	VA-0328	GE Combustion Turbine (3,482 MMBtu/hr)	**Control Method:** Oxidation catalyst and GCP **VOC Emission Limit 1:** 0.70 ppmvd at 15% O_2 without DB 1.40 ppmvd at 15% O_2 with DB (*no lb/MMBtu listed)* **VOC Startup/Shutdown Limit:** 60 lb/turbine/event cold start 60 minutes or

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
				less 0 lb/turbine/event warm start 50 minutes or less 14 lb/turbine/event hot start 30 minutes or less 65 lb/turbine/event shutdown 30 minutes or less
			Siemens Combustion Turbine (3,116 MMBtu/hr)	**Control Method:** Oxidation catalyst and GCP **VOC Emission Limits:** 1.0 ppmvd at 15% O_2 without DB 2.0 ppmvd at 15% O_2 with DB (*no lb/MMBtu listed)* **VOC Startup/Shutdown Limit:** 37 lb/turbine/event cold start 55 minutes or less 34 lb/turbine/event warm start 55 minutes or less 34 lb/turbine/event hot start 50 minutes or less 56 lb/turbine/event shutdown 38 minutes or less
Harrison Power	P0122266 (04/19/2018)	OH-0377	MHPS Combustion Turbine (3,231 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **VOC Emission Limit 1:** 2.0 ppmvd at 15% O_2 9.8 lb/hr with duct burner except SU/SD 1.0 ppmvd at 15% O_2, 4.7 lb/hr without duct burner except SU/SD 84.7 tons/yr for all operating modes including SU/SD 42.5 tons/yr for SU/SD (*no lb/MMBtu listed)*
			GE model 7HA.02 Combustion Turbine (3,459.6 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **VOC Emission Limits:** 2.0 ppmvd at 15% O_2 10.3 lb/hr with duct burner except SU/SD 1.0 ppmvd at 15% O_2 4.36 lb/hr without duct burner except SU/SD 49.1 tons/yr for all operating modes including SU/SD 4.81 tons/yr for SU/SD periods (*no lb/MMBtu listed)*
Harrison County Power Plant	R14-0036 (03/21/2018)	WV-0029	GE 7HA.02 Turbine (3,496.20 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **VOC Emission Limits:** 11.4 lb/hr 54.8 tons/yr 2.0 ppm with duct firing 1.0 ppm without duct firing (*no lb/MMBtu listed)*
Long Ridge Energy Generation LLC - Hannibal Power	P0122829 (11/07/2017)	OH-0375	General Electric Combustion Turbine (3,544 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **VOC Emission Limits:** 1.0 ppmvd at 15% O_2 4.54 lb/hr excluding SU/SD 26.4 tons/yr including SU/SD (*no lb/MMBtu listed)* **VOC SU/SD Emission Limits:** 78.1 lb/hr during cold startup. 11.5 lb/hr during hot startup, 12.0 lb/h during warm startup, 29.6 lb/h during shutdown.

Facility	Permit Number & Date	RBLC ID #	Emission Unit	VOC Requirements
			Siemens Combustion Turbine (3,602 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **VOC Emission Limit:** 2.0 ppmvd at 15% O_2 9.5 lb/hr with duct burner excluding SU/SD 1.0 ppmvd at 15% O_2 3.9 lb/hr without duct burner excluding SU/SD 50.8 tons/yr for all operating modes, including startup. (*no lb/MMBtu listed)* **VOC SU/SD Emission Limits:** 40.4 lb/hr during cold startup. 40.2 lb/hr during warm startup. 40.7 lb/hr during hot startup. 39.4 lb/hr during shutdown.
			Mitsubishi Combustion Turbine (3,544 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **VOC Emission Limits:** 2.0 ppmvd at 15% O_2. 8.8 lb/hr with duct burner excluding SU/SD 1.0 ppmvd at 15% O_2 4.6 lb/hr without duct burner excluding SU/SD 79.3 tons/yr for all operating modes, including startup. (*no lb/MMBtu listed)* **VOC SU/SD Emission Limits:** 224.7 lb/hr during cold startup. 225.1 lb/hr during warm startup. 185.9 lb/hr during hot startup. 97.0 lb/hr during shutdown.

* The P2/Add-on Description field for all pollutants of Renovo Energy Center LLC / Renovo PLT include "SCR, Catalytic Oxidizer." It appears that SCR and Catalytic Oxidizer were the default entry for this field for the entire RBLC entry, and does not really indicate that SCR was used for VOC control.

The results of the search of the RBLC and other available permits for VOC BACT/LAER precedents are presented in the table above. Based on this search, the use of an oxidation catalyst is the most stringent level of VOC control for natural gas-fired, combined-cycle CTGs. Therefore, the use of an oxidation catalyst represents the most stringent level of VOC control achieved in practice.

The BACT determinations provided in this table have VOC emissions greater than or equal to 1.0 ppmv, with the most recent project, Duke Energy Indiana, having a limit of 1.0 ppmv without duct firing.

BACT determinations for VOCs in the RBLC are greater than or equal to 1.0 ppmvd. Specifically, the four most recent projects have a VOC emission limit of 1.0 ppmvdc without duct firing.

<u>Step Five: Select BACT</u>

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the combustion turbine generator shall be as follows:

(1) The VOC emissions from CTG-01 shall be controlled by catalytic oxidation and good combustion practices.

(2) VOC emissions from CTG-01 shall not exceed 0.0013 pounds per MMBtu, excluding periods of startup and shutdown.

(3) VOC emissions from CTG-01 shall not exceed 1.0 ppmvd, excluding periods of startup and shutdown.

Startup and Shutdown Limitations:

(1) The VOC emissions from the combined cycle combustion turbine stack shall not exceed 18.8 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

The CTG proposed for the facility will utilize good combustion practices and exhaust through an oxidation catalyst to further reduce VOC emissions. VOC emissions from CTG-01 will be limited to 1.0 ppmvdc.

Since the most effective control equipment for VOC is being proposed, an economic analysis with respect to the cost-effectiveness of alternative controls has not been conducted. Energy-related impacts are directly translatable into economic impacts and similarly have not been examined.

One collateral environmental impact that has been identified with an oxidation catalyst is oxidation of SO_2 to SO_3. SO_3 can then form H_2SO_4 in the presence of H_2O and/or ammonia salts in the presence of NH_3. The conversion of SO_2 to SO_3 is adequately minimized by use of low-sulfur pipeline-quality natural gas as the sole fuel for the CTG, along with placement of the oxidation catalyst just upstream of the SCR system at a lower operating temperature. This lower temperature oxidation catalyst placement minimizes the oxidation of SO_2 to SO_3 that would otherwise occur, with placement of the oxidation catalyst at the HRSG outlet.

CO BACT Determination: Combined-Cycle Gas Turbine

Emissions of CO from the CTG occur as a result of incomplete combustion of the fuel. CO emissions are minimized by using proper combustor design, good combustion practices, and add-on controls. CTGs have inherently low CO emission rates due to their very efficient combustion.

Step One: Identify All Potentially Available Control Technologies

Emissions of carbon monoxide (CO) are generally controlled by oxidation. Oxidation technologies include regenerative thermal oxidation, catalytic oxidation, and flares.

(a) Regenerative thermal oxidation;
(b) Recuperative thermal oxidizer
(c) SCONOx Catalytic Absorption System;
(d) Catalytic oxidation;
(e) Good Combustion Controls; and
(f) Flares.

Below is the ranking of technically feasible CO control technologies identified for new large combined-cycle CTGs. The technologies identified below are the only CO control technologies that have been applied to a natural gas-fired CTG with a generating capacity greater than 100 MW in recent years.

Step Two: Eliminate Technically Infeasible Control Options

The next step in the process is to evaluate all possible options and determine if any of them are technically infeasible for the proposed project. The feasibility analysis for all the control technologies is shown below.

(a) 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, nevertheless it is also considered as a technology for controlling CO emissions. Upon passing through the flame, the waste gas containing CO 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 CO 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^{o}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 CO from properly operated natural gas combustion units without the use of a catalyst.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is not a technically feasible option for the combined cycle combustion turbine at this source.

(b) 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^{o}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 CO from properly operated natural gas combustion units without the use of a catalyst.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a recuperative thermal oxidizer is not a technically feasible option for the combined cycle combustion turbine at this source.

(c) SCONOx Catalytic Absorption System

This control technology utilizes a single catalyst to remove NO_X, CO, and VOC through oxidation. Now operating as EmeraChem, the current version of the technology is now marketed as EM_X. The operating temperature ranges from 300 - 700°F. The $SCONO_X$ Catalyst is sensitive to contamination by sulfur, so it must be used in conjunction with the $SCOSO_X$ catalyst, which favors sulfur compound absorption. This technology has only been demonstrated on units ranging from 5 to 45 MW.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a SCONOx Catalytic Absorption System is not a technically feasible option for combined cycle combustion turbine at this source.

(d) Oxidation Catalyst

Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling CO emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without 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.
Similar to thermal incineration, 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. This control is widely accepted as BACT for control of CO emissions from combined cycle combustion turbines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is a technically feasible option for combined cycle combustion turbine at this source.

(e) Flare

Although the CO 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 CO from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is not a technically feasible option for the combined cycle combustion turbine at this source.

(f) Good Combustion Control:

Good combustion control is a continued operation of the CTG at the appropriate oxygen range and temperature to promote complete combustion and minimize CO formation. Because CO is essentially a byproduct of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of CO emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. CO emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics.

CTG vendors have designed lean pre-mix DLN combustors for natural gas firing to provide a high degree of combustion efficiency. Combustion controls are commonly used in combination with an oxidation catalyst to minimize CO emissions. Combustion controls alone are less effective than an oxidation catalyst in combination with combustion controls.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Controls is a technically feasible option for the combined cycle combustion turbine at this source.

Step Three: Rank Remaining Control Technologies by Control Effectiveness

(1) Oxidation catalyst systems consist of a passive reactor comprised of a grid of metal panels with a platinum catalyst. CO reduction efficiencies in the range of 80 to 90 percent are typical, although CO reduction may at times be less than these values due to the low inlet concentrations expected from the CTG.

(2) Good combustion control

Step Four: 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) under Process Type Code 15.210 (Large Combustion Turbines - Natural Gas), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Summary of RBLC Database Review - Large Combustion Turbines - Natural Gas - CO

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO Requirements
Maple Creek Energy I LLC	Proposed	--	Combined Cycle Combustion Turbine Generator (4,253 MMBtu/hr)	**Control Method:** Good combustion practices and oxidation catalyst **CO Emission Limit:** 0.0044 lb/MMBtu, excluding SU/SD 2.0 ppmvd @ 15% O_2 excluding SU/SD **CO SU/SD Limit:** 52.2 tons per twelve (12) consecutive month period

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO Requirements
Maple Creek Energy LLC	Existing T153-45909-00056 (06/19/2023)	IN-0365	Combined Cycle Combustion Turbine CTGB (4,200 MMBtu/hr)	**Control Method:** Oxidation Catalyst and GCP **CO Emission Limits:** 2.0 ppmvd @ 15% O_2 3-HR avg. 0.0044 lb/MMBtu
Maple Creek Energy II LLC	Proposed	--	Combined Cycle Combustion Turbine Generator (4,253 MMBtu/hr)	**Control Method:** Good combustion practices and oxidation catalyst **CO Emission Limit:** 0.0044 lb/MMBtu, excluding SU/SD 2.0 ppmvd @ 15% O_2 excluding SU/SD **CO SU/SD Limit:** 52.2 tons per twelve (12) consecutive month period
Golden Spread Electric Cooperative, Inc.	109148, PSD1358M2, GHG41M2 (08/14/25)	TX-1000	Simple-Cycle Turbine (2,033 MMBtu/hr)	**No CO Emission Limit**
Duke Energy Indiana, Inc. - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	(2) Combustion Turbines (4,254 MMBtu/hr, each)	**Control Method:** Oxidation catalyst and good combustion practices **CO Emission Limits:** 2.0 ppmvd @ 15% O_2, excluding SU/SD (3-hr rolling average) 19.75 lb/hr, each CT, excluding SU/SD *(converts to 0.0046 lb/MMBtu)* **CO SU/SD Emission Limit:** 4,579.75 lb/hr (Cold Startup)
Wabash Valley Resources, LLC	167-45208-00091 (01/11/2024)	IN-0371	Integrated Gasification Combined Cycle Combustion Turbine (2,292 MMBtu/hr)	**No CO Emission Limit**
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Combustion Turbine (4,671 MMBtu/hr)	**Control Method:** Oxidation Catalyst and GCP **CO Emission Limit:** 1.5 ppmv at 15% O2. Except during SU/SD (*no lb/MMBtu listed)*
Entergy Texas, Inc. Orange County Advanced Power Station	166032 PSDTX1598 GHGPSDTX210 (03/13/2023)	TX-0939	Combined Cycle Turbines (1,215 MW and 6,762 Btu/hr)	**Control Method:** Oxidation Catalyst and GCP **CO Emission Limits:** 2.0 ppmvd @ 15% O_2 3-HR avg. 2.4 ppmvd @ 15% O_2 1-HR avg. (*no lb/MMBtu listed)*
Midland Cogeneration Venture Limited Partnership	10-23 (02/01/2023)	MI-0455	EUCTGHRSG1 (4,197.60 MMBtu/hr)	**Control Method:** Oxidation Catalyst and GCP **CO Emission Limits:** 2.0 ppmvd @ 15% O_2 24-HR avg. except SU/SD 24.2 lb/hr except SU/SD *(converts to 0.0058 lb/MMBtu)* **CO SU/SD Emission Limit:** 1486.0 lb/hr during SU/SD
Lansing Board of Water and Light - Erickson Station	74-18D (12/20/2022)	MI-0454	EUCTGHRSG1 and EUCTGHRSG2 (667 MMBtu/hr, each)	**Control Method:** Oxidation Catalyst and GCP **CO Emission Limit:** 4.0 ppmvd @ 15% O_2 24-HR avg. except SU/SD in combined cycle mode 9.0 lb/hr except SU/SD for HRSG bypass *(converts to 0.013 lb/MMBtu)* **CO SU/SD Emission Limit:** 289 lb/hr during SU/SD in combined cycle mode

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO Requirements
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	Combined Cycle Combustion Turbine (3,647 MMBtu/hr)	**Control Method:** Oxidation catalyst and good combustion practices **CO Emission Limit 1:** 1.5 ppmv @ 15% O2 Turbine load > 60% w/o duct burners except SU/SD **CO Emission Limit 2:** 1.8 ppmv @ 15% O2 Turbine load > 60% with duct burners except SU/SD **CO Emission Limit 3:** 2.0 ppmv @ 15% O2 for turbine load < 60% except SU/SD (*no lb/MMBtu listed)* **CO SU/SD Emission Limit:** During any clock hour, including SU/SD and breakdown, emissions shall not exceed 923 pounds/hour (cold start/shakedown); 325 pounds/hour (non-cold start); 216 pounds/hour (shutdown).
Alaska Gasline Development Corporation Liquefaction Plant	AQ1539CPT01 (07/07/2022)	AK-0088	(4) Combined Cycle Gas-Fired Turbines (384 MMBtu/hr, each)	**Control Method:** Oxidation Catalyst and GCP **CO Emission Limit (each):** 2.0 ppmv @ 15% O_2 3-hr avg. (*no lb/MMBtu listed)*
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Combined Cycle Natural Gas-Fired Combustion Turbine Generator with HRSG (3,064 MMBtu/hr)	**Control Method:** Oxidation catalyst and good combustion practices **CO Emission Limit:** 2.0 ppm 24-hr rolling avg. except SU/SD (*no lb/MMBtu listed)* **CO SU/SD Emission Limit:** 788.6 lb/hr during SU/SD
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/03/2022)	MI-0452	Combined Cycle Natural Gas-Fired Combustion Turbine Generator with HRSG (3,064 MMBtu/hr)	**Control Method:** Oxidation catalyst and good combustion practices **CO Emission Limit:** 2.0 ppm 24-hr rolling avg. except SU/SD (*no lb/MMBtu listed)* **CO SU/SD Emission Limit:** 788.6 lb/hr during SU/SD
Magnolia Power LLC- Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Combined Cycle Gas Turbine (5,081 MMBtu/hr)	**Control Method:** Catalytic oxidation and good combustion practices **CO Emission Limit:** 2.0 ppmvd 24-hr rolling avg. except SU/SD (*no lb/MMBtu listed)* **CO Emission Limit:** 1620 lb/hr during SU/SD
Mountain State Clean Energy LLC Maidsville	R14-0038 (01/05/2022)	WV-0033	Combustion Turbine and Duct Burner (1,275 MW / 3,875 MMBtu/hr)	**Control Method:** Oxidation catalyst and good combustion practices **CO Emission Limit:** 2.0 ppmvd at 15% O_2, excluding SU/SD, ea. CT 20.76 lb/hr except SU/SD (CT-01) *(converts to 0.0054 lb/MMBtu)* 19.54 lb/hr except SU/SD (CT-02) *(converts to 0.0050 lb/MMBtu)*
Shady Hills Energy Center, LLC	1010524-003-AC / PSD-FL-444A (06/07/2021)	FL-0371	Combustion Turbine and HRSG with Duct Firing (3,622 MMBtu/hr)	**Control Method:** Clean burning fuel and GCP **CO Emission Limits:** 4.3 ppmvd @ 15% O2 (Turbine loads > 90%) 7.1 ppmvd @ 15% O2 (Turbine loads < 90%) 6.5 ppmvd @15% O2 (when duct firing) (*no lb/MMBtu listed)*

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO Requirements
Renovo Energy Center LLC / Renovo PLT	18-00033B (04/29/2021)	PA-0334	Combustion Turbines with Duct Burners #1 and #2 (4,546 MMBtu/hr, each)	**Control Method:** Oxidation Catalyst **CO Emission Limits:** 1.5 ppmvd @ 15% O_2 / 1 hr 15.2 lb/hr *(converts to 0.0033 lb/MMBtu)*
Virginia Electric and Power Company	52404-5 (12/01/2020)	VA-0334	Combustion Turbine Generator (3,442 MMBtu/hr)	**Control Method:** Oxidation catalyst and good combustion practices **CO Emission Limit:** 416 lbs/day, CEMS (*converts to 0.0050 lb/MMBtu)*
Alabama Power Company	503-1001 (11/09/2020)	AL-0328	(2) Combined Cycle Units (744 MW)	**Control Method:** Oxidation Catalyst **CO Emission Limit:** 23.8 lb/hr 0.005 lb/MMBtu
FG LA Complex	PSD-LA-812 (01/06/2020)	LA-0364	Natural Gas Cogeneration Units (2,222 MMbtu/hr)	**Control Method:** Good combustion practices and catalytic oxidation **CO Emission Limit:** 4.0 ppmvd @ 15% O_2 (*no lb/MMBtu listed)*
Indeck Niles, LLC	75-16B (11/26/2019)	MI-0445	Natural Gas Combined-cycle Turbine (3,421 MMBtu/hr)	**Control Method:** Oxidation Catalyst and GCP **CO Emission Limits:** 4.0 ppmvd @15% O_2 24-hr roll avg except SU/SD 24.7 lb/hr 24-hr rolling avg. except SU/SD *(converts to 0.0072 lb/MMBtu)* **CO SU/SD Emission Limit:** 3537 lb/h based on operating hour during startup or shutdown. SU/SD operations are limited to 500 hours per 12-month
Thomas Township Energy, LLC	210-18 (8/21/2019)	MI-0442	Natural Gas Combined-cycle Turbine (625 MW, 4,200 MMBtu/hr)	**Control Method:** Oxidation Catalyst and GCP **CO Emission Limit 1:** 2.0 ppmvd 24-hr roll avg except during SU/SD (*no lb/MMBtu listed)* **CO Emission Limit 2:** 2,106 lb/hr including SU/SD
ESC Tioga County Power LLC / Electric Power Generation Facility	59-00034A (08/20/2019)	PA-0333	Combustion Turbine / Duct Burner (4,469 MMBtu/hr)	**Control Method:** None **CO Emission Limit 1:** 1.5 ppmvd @ 15% O_2 (*no lb/MMBtu listed)* **CO Emission Limit 2:** 92.5 tons per 12 consecutive month period *(converts to 0.0047 lb/MMBtu)*
Cogen Tech Linden Venture LP	41809 / BOP170001 (7/30/2019)	NJ-0088	250 MW Combined Cycle Combustion Turbine (2,517 MMBtu/hr)	**Control Method:** Oxidation Catalyst **CO Emission Limits:** 11.1 lb/hr *(converts to 0.0044 lb/MMBtu)* 2.0 ppmvd @15% O_2 3 h rolling av
Chickahominy Power LLC	52610-1 (6/24/2019)	VA-0332	Combustion Turbine (4,066 MMBtu/hr)	**Control Method:** Oxidation Catalyst and GCP **CO Emission Limits:** 1.0 ppmvd @ 15% O_2 94.3 tons/yr *(converts to 0.0053 lb/MMBtu)* **CO SU/SD Emission Limits:** 444 lb/turbine/event cold start =<42 min 396 lb/turbine/event warm start =<42 min 252 lb/turbine/event hot start =<42 min 156 lb/turbine/event shutdown=<42 min

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO Requirements
Jackson Generation, LLC Jackson Energy Center	17040013 (12/31/2018)	IL-0130	Combined-cycle Turbine (3,864 MMBtu/hr)	**Control Method:** Oxidation Catalyst **CO Emission Limits:** 2.0 ppmv at 15% O2 with duct burner. 33.9 lbs/hr. Excludes SU/SD 211.5 ppmv at 15% O2 without duct burner. 30.5 lbs/hr, except SU/SD *(converts to 0.0079 lb/MMBtu)* **CO Emission Limit for SU/SD:** 483.5 lbs/hr (startup/shutdown/commissioning) **CO Emission Limit for tuning:** 239 lbs/hr **CO Emission Limit for very low load:** 20.6 lbs/hr
ESC Brooke County Power I, LLC Brooke County Power Plant	R14-0035 (9/18/2018)	WV-0032	Combined-cycle / GE 7HA.01 Turbine (462.5 MW, 2,737.7 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **CO Emission Limits:** 2.0 ppm 14.1 lb/hr *(converts to 0.0052 lb/MMBtu)*
APV Renaissance Partners Renaissance Energy Center	30-00235A (08/27/2018)	PA-0319	Combustion Turbine (2,665.9 MMBtu/hr)	**Control Method:** Oxidation Catalyst **CO Emission Limits:** 2.0 ppmdv @ 15% O_2 187.44 tons/yr *(converts to 0.017 lb/MMBtu)*
CPV Three Rivers, LLC	16060032 (07/30/2018)	IL-0129	Combined-cycle Turbine (3,474 MMBtu/hr)	**Control Method:** Oxidation Catalyst **CO Emission Limit:** 2.0 ppmv at 15%O2 excluding SU/SD (*no lb/MMBtu listed)* **Permit limits are as follows:** With duct burner: 19.0 lb/hr *(converts to 0.0055 lb/MMBtu)* Without duct burner: 15.4 lb/hr *(converts to 0.0044 lb/MMBtu)* For ULSD: 17.0 lb/hr For periods of SU/SD and commissioning: Extended startups using natural gas: 1522 lb/hr Commissioning and other than extended startups using natural gas: 204 lb/hr ULSD: 231 lb/hr For periods of tuning: Natural Gas: 204 lb/hr ULSD: 231 lb/hr
DTE Electric Company / Belle River Combined Cycle Power Plant	19-18 (07/16/2018)	MI-0435	Two (2) Combined-Cycle Natural Gas-Fired Combustion Turbine Generators with HRSGs (3,658 MMBtu/hr, each)	**Control Method:** Oxidation catalyst technology and good combustion practices **CO Emission Limit:** 0.0045 lb/MMBtu, each unit, except SU/SD 17.59 lb/hr, each unit, except SU/SD 791.5 lb/hr, each unit, during SU/SD
Novi Energy	52588 (04/26/2018)	VA-0328	GE Combustion Turbine (3,482 MMBtu/hr)	**Control Method:** Oxidation catalyst and GCP **CO Emission Limits:** 1.0 ppmvd at 15% O_2 3-hour avg., without DB 1.6 ppmvd at 15% O_2 3-hour avg., with DB (*no lb/MMBtu listed)* **CO SU/SD Emission Limit:** 840 lb/turbine/event cold start 60 min or less 188 lb/turbine/event warm start 50 min or less 180 lb/turbine/event hot start 30 min or less 100 lb/turbine/event shutdown 30 min or less
			Siemens Combustion Turbine (3,116 MMBtu/hr)	**Control Method:** Oxidation catalyst and GCP **CO Emission Limit:**

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO Requirements
				1.8 ppmvd at 15% O_2 3-hour avg. with or without DB (*no lb/MMBtu listed)* **CO SU/SD Emission Limits:** 434 lb/turbine/event cold start 55 min or less 397 lb/turbine/event warm start 55 min or less 36 lb/turbine/event hot start 50 min or less 184 lb/turbine/event shutdown 38 min or less
Palmdale Energy, LLC	SE 17-01 (04/25/2018)	CA-1251	Combustion Turbine (2,217 MMBtu/hr)	**Control Method:** Oxidation Catalyst **CO Emission Limit 1:** 1.5 ppmvd at 15% O_2., demo limit w/o duct firing 2.0 ppm @ 15% O_2 with duct firing 11.3 lb/hr with duct firing *(converts to 0.0051 lb/MMBtu)* 7.8 lb/hr without duct firing *(converts to 0.0035 lb/MMBtu)* **CO SU/SD Emission Limits:** Cold Start: 416 lb/event, 39 min. Warm Start: 378 lb/event, 35 min. Hot Start: 305 lb/event, 30 min. Shutdown: 75.9 lb/event, 25 min.
Harrison Power	P0122266 (04/19/2018)	OH-0377	MHPS Combustion Turbine (3,231 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **CO Emission Limits:** 2.0 ppmvd at 15% O_2 17.1 lb/hr with duct burner except SU/SD *(converts to 0.0053 lb/MMBtu)* 16.3 lb/hr without duct burner except SU/SD *(converts to 0.0050 lb/MMBtu)* 109.1 tons/yr for all operating modes including SU/SD **CO SU/SD Emission Limit:** 35.40 tons/yr for SU/SD period
			GE model 7HA.02 Combustion Turbine (3,459.6 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **CO Emission Limits:** 2.0 ppmvd at 15% O_2 17.9 lb/hr with duct burner except SU/SD *(converts to 0.0052 lb/MMBtu)* 15.3 lb/hr without duct burner except SU/SD *(converts to 0.0044 lb/MMBtu)* 112.8 tons/yr for all operating modes including SU/SD **CO SU/SD Emission Limit:** 35.85 tons/yr for SU/SD periods
Harrison County Power Plant	R14-0036 (03/21/2018)	WV-0029	GE 7HA.02 Turbine (3,496.20 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **CO Emission Limits:** 20.0 lb/hr 1-hr avg. *(converts 0.0057 lb/MMBtu)* 124.0 tons/yr 2.0 ppm
Long Ridge Energy Generation LLC - Hannibal Power	P0122829 (11/07/2017)	OH-0375	General Electric Combustion Turbine (3,544 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **CO Emission Limits:** 2.0 ppmvd at 15% O_2 15.9 lb/hr excluding SU/SD *(converts to 0.0045 lb/MMBtu)* 123.8 tons/yr including SU/SD **CO SU/SD Emission Limits:** 877.0 lb/hr during cold startup 145.3 lb/hr during hot startup 130.6 lb/hr during warm startup

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO Requirements
				137.7 lb/hr during shutdown.
			Siemens Combustion Turbine (3,602 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **CO Emission Limits:** 2.0 ppmvd at 15% O_2 16.5 lb/hr with duct burner excluding SU/SD *(converts to 0.0046 lb/MMBtu)* 13.6 lb/hr without duct burner excluding SU/SD *converts to 0.0038 lb/MMBtu)* 142.6 tons/yr for all operating nodes including SU/SD **CO SU/SD Emission Limits:** 447.9 lb/hr during cold startup 370.3 lb/hr during hot startup 439.9 lb/hr during warm startup 118.5 lb/hr during shutdown.
			Mitsubishi Combustion Turbine (3,544 MMBtu/hr)	**Control Method:** Oxidation Catalyst, GCP **CO Emission Limit 1:** 2.0 ppmvd at 15% O_2. 15.3 lb/hr with duct burner excluding SU/SD *(converts to 0.0043 lb/MMBtu)* 16.1 lb/hr without duct burner excluding SU/SD *(converts to 0.0045 lb/MMBtu)* 121.2 tons/yr for all operating modes including Startup **CO SU/SD Emission Limits:** 538.6 lb/hr during cold startup. 140.7 lb/hr during hot startup, 449.4 lb/hr during warm startup, 162.7 lb/hr during shutdown.

Based on the table above, the use of an oxidation catalyst is the most stringent level of CO control for natural gas-fired combined-cycle CTGs. Therefore, the use of an oxidation catalyst is considered to represent the most stringent level of CO control achieved in practice.

Most of the recently permitted combined-cycle power projects have a CO limit of 2.0 parts per million by volume (ppmv). The most recently permitted combined-cycle power project (2023) with a lower limit is Nemandji Trail Energy Center with a CO limit of 1.5 ppmv with a 168-hour rolling average. While this limit is lower than other recent determinations, it is based on a much longer averaging period. More recent BACT determinations of 2.0 ppmv have averaging periods of 3 hours or lower, which is consistent with the limit proposed for the Facility and the current MCE I project's limit.

The Chickahominy Power project in Virginia has a permitted CO limit of 1.0 ppmvdc. Low CO limits impose a significant operating restriction for this type of facility. This is demonstrated by the higher facility-wide CO emissions for the Chickahominy project due to elevated SU/SD emissions. The Chickahominy project has annual potential CO emissions of 322.9 tpy for three Mitsubishi turbine trains. Therefore, the CO BACT limits for Chickahominy, taking into account all modes of operation including steady-state and SU/SD, are not as stringent as the proposed CO BACT limits for MCE II. In addition, the Chickahominy project has been cancelled, and therefore these limits will not be demonstrated.

Lincoln Land Energy Center has a 1.8 ppmvdc limit at less than a 60 percent load and a 1.5 ppmvdc limit (without duct firing) at greater than a 60 percent load. This supports the discussion above that CO emissions generally increase at lower loads due to inefficient combustion. The overall limit of 1.8 ppmvdc is generally consistent with the Facility's proposed limit of 2.0 ppmvdc. It is important to note that the VOC emissions limit for the Lincoln Land Energy Center (without duct firing) is 1.1 ppmvdc, a little higher than the emissions proposed for the Facility. It is common that optimizing combustion for lower VOC emissions could result in a relative increase in CO emissions.

Some sources that utilize duct firing may take more stringent limits. For example, ESC Tioga County Power LLC has a CO emission limit of 1.5 ppmvd and 92.5 tons per twelve (12) consecutive month period (equivalent to 0.0047 lb/MMBtu) with duct firing. Similarly, Renovo Energy Center LLC utilizes duct burners and has a CO emission limit of 1.5 ppmvd and 15.2 pounds per hour (equivalent to 0.0033 lb/MMBtu).

Jackson Energy has a BACT limit of 2.0 ppmvdc, with a lower limit of 1.5 ppmvdc required 36 months after commissioning. Supporting documentation for Jackson Energy's BACT analysis and the information in the BACT/LAER Clearinghouse confirm that BACT for Jackson Energy was determined to be 2.0 ppmvdc.

While the concentration-based emission limits may vary slightly based on averaging times, turbine technologies, and other operational parameters, the most stringent controls proposed for the projects in the table above are the use of an oxidation catalyst with good combustion practices. All of the other projects listed in the table above have CO limits of 2.0 ppmvdc or greater. Specifically, BACT for the two most recent projects utilizing H-class turbine technology have a CO emission limit of 2.0 ppmvdc without duct firing. The Facility’s proposed CO limit of 2.0 ppmvdc is consistent with, or more stringent than, a majority of CO limits listed in the table above.

<u>Step Five: Select BACT</u>

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the combustion turbine generator shall be as follows:

(1) The CO emissions from CTG-01 shall be controlled using good combustion practices and an oxidation catalyst.

(2) CO emissions from CTG-01 shall not exceed 2.0 ppmvd @ 15% O2, excluding periods of startup and shutdown.

(3) CO emissions from CTG-01 shall not exceed 0.0044 pounds per MMBtu, excluding periods of startup and shutdown.

<u>Startup and Shutdown Limitations:</u>

(1) The CO emissions from the combined cycle combustion turbine stack shall not exceed 52.2 tons per twelve (12) consecutive month period, for the duration of the combined startup and shutdown events, with compliance determined at the end of each month.

A review of the recently permitted projects in RBLC shows that the proposed BACT is consistent with a great majority of CO limits listed above. This limit will be met using the most stringent emissions control practices available for CO, good combustion practices, and an oxidation catalyst. Since the most effective control equipment for CO is being proposed, an economic analysis with respect to the cost-effectiveness of alternative controls has not been conducted. Energy-related impacts are directly translatable into economic impacts and similarly have not been examined.

One collateral environmental impact that has been identified with an oxidation catalyst is oxidation of SO_2 to SO_3. SO_3 can then form H_2SO_4 in the presence of H_2O and/or ammonia salts in the presence of NH_3. The conversion of SO_2 to SO_3 is adequately minimized by use of low-sulfur pipeline-quality natural gas as the sole fuel for the CTG, along with placement of the oxidation catalyst just upstream of the SCR system at a lower operating temperature. This lower temperature oxidation catalyst placement minimizes the oxidation of SO_2 to SO_3 that would otherwise occur, with placement of the oxidation catalyst at the HRSG outlet.

H_2SO_4 BACT Determination: Combined-Cycle Gas Turbine

Step 1: Identify Potential Control Technologies (H_2SO_4)

Emissions of Sulfuric Acid (H_2SO_4) emissions depend upon the sulfur content of the fuel and oxidation of SO_2 to SO_3, followed by immediate conversion of SO_3 to H_2SO_4 when water vapor is present. Sulfuric Acid (H_2SO_4) emissions are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

(1) Flue Gas Desulfurization (FGD) System;
(2) Dry Sorbent Injection; and
(3) Fuel Specification.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency. H_2SO_4 emissions are not dependent upon combustion turbine properties such as size or burner design.

Step 2: Eliminate Technically Infeasible Options (H_2SO_4)

(a) Flue Gas Desulfurization (FGD) System

A flue gas desulfurization system (FGD) is comprised of a spray dryer that uses lime as a reagent followed by particulate control or wet scrubber that uses limestone as a reagent. FGD is an established technology. FGD typically operates at a temperature of approximately 300°F to 700°F (wet) and 300°F to 1830°F (dry). The FGD has a waste stream inlet pollutant concentration of 2,000ppmv. Absorption of SO_2 is accomplished by the contact between the exhaust and an alkaline reagent, which results in the formation of neutral salts. Wet systems employ reagents using packed or spray towers and generate wastewater streams, while dry systems inject slurry reagent into the exhaust stream to react, dry and be removed downstream by particulate control equipment. By removing SO_2 from the exhaust stream, conversion of SO_2 to SO_3 and H_2SO_4 is reduced. Chlorine emissions can result in salt deposition within the absorber and in downstream equipment. Wet systems may require flue gas re-heating downstream of the absorber to prevent corrosive condensation. Inlet streams for dry systems must be cooled as appropriate, and dry systems require use of particulate controls to collect the solid natural salts.

FGD systems are not listed in the RBLC as BACT for the control of H_2SO_4 emissions for large, combined cycle combustion turbines. Technology has not been applied to natural gas combined cycle combustion turbines due to very low SO_2 and H_2SO_4 emissions. Controls would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of flue gas desulfurization system (FGD) is not a technically feasible option for the combined cycle combustion turbine at this source.

(b) Dry Sorbent Injection

A post-combustion technology in which a calcium or sodium-based sorbent reacts with SO_2 and SO_3 and is removed downstream by particulate control equipment. The reduced availability of SO_2 and SO_3 in the exhaust stream reduces H_2SO_4 formation, thereby reducing H_2SO_4 emissions. The system requires use of particulate controls to collect the reaction solids.
Technology has not been applied to natural gas combined cycle combustion turbines due to very low SO_2 and H_2SO_4 emissions. Controls would not provide any measurable emission reduction. Dry sorbent injection is not listed in the RBLC as BACT for the control of H_2SO_4 emissions for large, combined cycle combustion turbines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of dry sorbent injection is not a technically feasible option for the combined cycle combustion turbine at this source.

(c) Fuel Specifications

Combusting only clean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating H_2SO_4 emissions. Fuel Specifications are included in RBLC for the control of H_2SO_4 from combined cycle combustion turbines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Fuel Specifications is a technically feasible option for the combined cycle combustion turbine at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness (H_2SO_4)

The following measures have been identified for control of H_2SO_4 resulting from the operation of the combined cycle combustion turbine.

(1) Fuel Specifications

Step 4: Evaluate Top Control Alternatives (H_2SO_4)

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) under Process Type Code 15.210 (Large Combustion Turbines - Natural Gas), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Summary of RBLC Database Review - Large Combustion Turbines - Natural Gas - H_2SO_4

Facility	Permit Number & Date	RBLC ID #	Emission Unit	H_2SO_4 Requirements
Maple Creek Energy I LLC	Proposed	--	Combined Cycle Combustion Turbine Generator (4,253 MMBtu/hr)	**Control Method:** Use of pipeline-quality natural gas **SO_2 Emission Limit:** 0.0019 lb/MMBtu **H_2SO_4 Emission Limit:** 0.0013 lb/MMBtu
Maple Creek Energy I LLC	Existing T153-45909-00056 (06/19/2023)	IN-0365	Combined Cycle Combustion Turbine CTGB (4,200 MMBtu/hr)	**Control Method:** GCP, pipeline quality natural gas **H_2SO_4 Emission Limit:** 0.0013 lb/MMBtu

Facility	Permit Number & Date	RBLC ID #	Emission Unit	H_2SO_4 Requirements
Maple Creek Energy II LLC	Proposed	--	Combined Cycle Combustion Turbine Generator (4,253 MMBtu/hr)	**Control Method:** Use of pipeline-quality natural gas **SO_2 Emission Limit:** 0.0019 lb/MMBtu **H_2SO_4 Emission Limit:** 0.0013 lb/MMBtu
Golden Spread Electric Cooperative, Inc.	109148, PSD1358M2, GHG41M2 (08/14/25)	TX-1000	Simple-Cycle Turbine (2,033 MMBtu/hr)	**No H_2SO_4 Emission Limit**
Duke Energy, Indiana, Inc. - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	Two (2) Combustion Turbines (4,254 MMBtu/hr)	**No H_2SO_4 Emission Limit**
Wabash Valley Resources, LLC	167-45208-00091 (01/11/2024)	IN-0371	Integrated Gasification Combined Cycle Combustion Turbine (2,292 MMBtu/hr)	**No H_2SO_4 Emission Limit**
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Combustion Turbine (4,671 MMBtu/hr)	**Control Method:** GCP, pipeline quality natural gas **H_2SO_4 Emission Limit:** 9.9 lb/hr natural gas, with DF *(converts to 0.0021 lb/MMBtu)* 7.8 lb/hr natural gas, without DF *(converts to 0.0017 lb/MMBtu)*
Entergy Texas, Inc. Orange County Advanced Power Station	166032 PSDTX1598 GHGPSDTX210 (03/13/2023)	TX-0939	Combined Cycle Turbines (1,215 MW and 6,762 Btu/hr)	**Control Method:** GCP, low sulfur fuel **H_2SO_4 Emission Limit:** 0.33 gr/100 dscf *(converts to 0.0046 lb/MMBtu)*
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	Combined Cycle Combustion Turbine (3,647 MMBtu/hr)	**Control Method:** GCP, Natural gas with sulfur content of no more than 0.5 grains/100 scf **H_2SO_4 Emission Limit:** 2.0 lb/MMBtu
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Combined Cycle Natural Gas-Fired Combustion Turbine Generator with HRSG (3,064 MMBtu/hr)	**Control Method:** GCP, use of pipeline quality natural gas **H_2SO_4 Emission Limit:** 2.6 lb/hr *(converts 0.00085 lb/MMBtu)*
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/03/2022)	MI-0452	Combined Cycle Natural Gas-Fired Combustion Turbine Generator with HRSG (3,064 MMBtu/hr)	**Control Method:** GCP, use of pipeline quality natural gas **H_2SO_4 Emission Limit:** 2.6 lb/hr *(converts 0.00085 lb/MMBtu)*
Magnolia Power LLC- Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Combined Cycle Gas Turbine (5,081 MMBtu/hr)	**Control Method:** GCP **H_2SO_4 Emission Limits:** 0.0062 gr/dscf *(converts to 0.0009 lb/MMBtu)* 2.28 lb/hr *(converts to 0.00045 lb/MMBtu)*
Mountain State Clean Energy LLC Maidsville	R14-0038 (01/05/2022)	WV-0033	Combustion Turbine and Duct Burner (3,875 MMBtu/hr)	**Control Method:** Low Sulfur Fuel **SO_2 / H_2SO_4 Emission Limits:** 0.4 gr-s/100 scf (see Appendix D of 40 CFR 75) 4.28 lb/hr *(converts to 0.0011 lb/MMBtu)*
Shady Hills Energy Center, LLC	1010524-003-AC / PSD-FL-444A (06/07/2021)	FL-0371	Combustion Turbine and HRSG with Duct Firing (3,622 MMBtu/hr)	**Control Method:** Clean Fuels **H_2SO_4 Emission Limit:** 2.0 gr-s/100 scf *(converts to 0.0028 lb/MMBtu)*

Facility	Permit Number & Date	RBLC ID #	Emission Unit	H_2SO_4 Requirements
Renovo Energy Center LLC / Renovo PLT	18-00033B (04/29/2021)	PA-0334	Combustion Turbines with Duct Burners #1 and #2 (4,546 MMBtu/hr, each)	**Control Method:** SCR, Catalytic Oxidizer **H_2SO_4 Emission Limits:** 0.0009 lb/MMBtu 4.07 lb/hr
Indeck Niles, LLC	75-16B (11/26/2019)	MI-0445	Natural Gas Combined-cycle Turbine (3,421 MMBtu/hr)	**Control Method:** GCP, pipeline quality natural gas **H_2SO_4 Emission Limit:** 4.6 lb/hr *(converts to 0.0013 lb/MMBtu)*
Thomas Township Energy, LLC	210-18 (8/21/2019)	MI-0442	Natural Gas Combined-cycle Turbine (625 MW, 4,200 MMBtu/hr)	**Control Method:** The use of clean fuel (natural gas), with a fuel sulfur limit of 1 grain per 100 standard cubic feet of natural gas **H_2SO_4 Emission Limit:** 0.0013 lb/MMBtu hourly
Cogen Tech Linden Venture LP	41809 / BOP170001 (7/30/2019)	NJ-0088	250 MW Combined Cycle Combustion Turbine (2,517 MMBtu/hr)	**Control Method:** Use of clean burning fuels **H_2SO_4 Emission Limit:** 3.45 lb/hr *(converts to 0.0014 lb/MMBtu)*
Chickahominy Power LLC	52610-1 (6/24/2019)	VA-0332	Combustion Turbine (4,066 MMBtu/hr)	**Control Method:** Pipeline quality NG **H_2SO_4 Emission Limits:** Max. sulfur content of 0.4 gr S per 100 scf 0.0012 lb/MMBtu 21.4 tons/yr
Jackson Generation, LLC Jackson Energy Center	17040013 (12/31/2018)	IL-0130	Combined-cycle Turbine (3,864 MMBtu/hr)	**Control Method:** None **H_2SO_4 Emission Limit:** 5.0 lb/hr *(converts to 0.0013 lb/MMBtu listed)*
ESC Brooke County Power I, LLC Brooke County Power Plant	R14-0035 (9/18/2018)	WV-0032	Combined-cycle / GE 7HA.01 Turbine (462.5 MW, 2,737.7 MMBtu/hr)	**Control Method:** None **H_2SO_4 Emission Limits:** 2.6 lb/hr 0.0008 lb/MMBtu
APV Renaissance Partners Renaissance Energy Center	30-00235A (08/27/2018)	PA-0319	Combustion Turbine (2,665.9 MMBtu/hr)	**Control Method:** None **H_2SO_4 Emission Limit:** 5.98 tons/year *(converts to 0.0022 lb/MMBtu listed)*
CPV Three Rivers, LLC	16060032 (07/30/2018)	IL-0129	Combined-cycle Turbine (3,474 MMBtu/hr)	**Control Method:** None **H_2SO_4 Emission Limits:** 2.8 lb/hr with duct burner *(converts to 0.0008 lb/MMBtu)* 2.3 lb/hr without duct burner *(converts to 0.0007 lb/MMBtu)*
DTE Electric Company / Belle River Combined Cycle Power Plant	19-18 (07/16/2018)	MI-0435	Two (2) Combined-Cycle Natural Gas-Fired Combustion Turbine Generators with HRSGs (3,658 MMBtu/hr, each)	**Control Method:** Good combustion practices and the use of pipeline quality natural gas **H_2SO_4 Emission Limits:** 0.0013 lb/MMBtu, each unit 5.04 lb/hr, each unit, w/o duct burner
Novi Energy	52588 (04/26/2018)	VA-0328	GE Combustion Turbine (3,482 MMBtu/hr)	**Control Method:** None **H_2SO_4 Emission Limits:** Sulfur content of fuel no more than 4.0 grains per 100 scf 2.5 lb/hr without DF *(converts to 0.00072 lb/MMBtu)* 2.7 lb/hr with DF *(converts to 0.00078 lb/MMBtu)*
			Siemens Combustion Turbine	**Control Method:** None **H_2SO_4 Emission Limits:**

Facility	Permit Number & Date	RBLC ID #	Emission Unit	H_2SO_4 Requirements
			(3,116 MMBtu/hr)	Sulfur content of fuel no more than 4.0 grains per 100 scf 2.2 lb/hr without DF *(converts to 0.00071 lb/MMBtu)* 2.7 lb/hr with DF *(converts to 0.00087 lb/MMBtu)*
Harrison Power	P0122266 (04/19/2018)	OH-0377	MHPS Combustion Turbine (3,231 MMBtu/hr)	**Control Method:** GCP, pipeline quality natural gas **H_2SO_4 Emission Limits:** 0.0022 lb/MMBtu (7.74 lb/hr) with duct burner 0.0022 lb/MMBtu (7.41 lb/hr) without duct burner 31.69 tons/yr
			GE model 7HA.02 Combustion Turbine (3,459.6 MMBtu/hr)	**Control Method:** GCP, pipeline quality natural gas **H_2SO_4 Emission Limits:** 0.0010 lb/MMBtu (3.52 lb/hr) with duct burner. 0.00103 lb/MMBtu (4.13 lb/hr) with duct burner except SU/SD. 0.00102 lb/MMBtu (3.52 lb/hr) without duct burner. 17.55 tons/yr
Harrison County Power Plant	R14-0036 (03/21/2018)	WV-0029	GE 7HA.02 Turbine (3496.20 MMBtu/hr)	**Control Method:** Use of natural gas **H_2SO_4 Emission Limits:** 3.8 lb/hr 16.7 tons/yr 0.0009 lb/MMBtu
Long Ridge Energy Generation LLC - Hannibal Power	P0122829 (11/07/2017)	OH-0375	General Electric Combustion Turbine (3,544 MMBtu/hr)	**Control Method:** None **H_2SO_4 Emission Limits:** 0.0011 lb/MMBtu 3.78 lb/hr 16.56 tons/yr or all operating modes, including startup
			Siemens Combustion Turbine (3,602 MMBtu/hr)	**Control Method:** None **H_2SO_4 Emission Limit 1:** 0.00052 lb/MMBtu with duct burner except SU/SD 0.00055 lb/MMBtu without duct burner except SU/SD **H_2SO_4 Emission Limit 2:** 1.81 lb/hr with duct burners except SU/SD 1.50 lb/hr without duct burner except SU/SD **H_2SO_4 Emission Limit 3:** 7.9 tons/yr or all operating modes, including startup
			Mitsubishi Combustion Turbine (3,544 MMBtu/hr)	**Control Method:** None **H_2SO_4 Emission Limit 1:** 0.009 lb/MMBtu **H_2SO_4 Emission Limit 2:** 2.85 lb/hr with duct burners except SU/SD 2.99 lb/hr without duct burner except SU/SD **H_2SO_4 Emission Limit 3:** 13.1 tons/yr or all operating modes, including startup

The results of the search of the RBLC confirm that the only H_2SO_4 BACT technology identified for large combined-cycle turbines is use of clean fuel (i.e., natural gas). There were no cases identified of any post combustion controls used to control H_2SO_4 emissions from CTGs.

The results in the table above provide BACT emissions for H_2SO_4 expressed as either lb/MMBtu or lb/hr, or both. A relatively wide range of BACT emission rates were found for gas firing, the largest being 0.0022 lb/MMBtu and most being around 0.001 lb/MMBtu. This reflects a range of assumed natural gas sulfur contents and SO_2 to SO_3 conversion rates. The projects shown above with lower H_2SO_4 rates appear to have assumed a very low natural gas sulfur content and/or assumed low rates for the oxidation of SO_2 to SO_3 from a CO catalyst. The source assumed a fuel sulfur content of 0.5 grains per dry standard cubic feet, with the SO_2 to SO_3 conversion dependent on the turbine technology.

The H_2SO_4 emission limits proposed by Renovo Energy Center LLC (0.0009 lb/MMBtu) and Brooke County Power Plant (0.0008 lb/MMBtu) were never demonstrated as these facilities withdrew plans for construction. Additionally, Long Ridge Energy Generation LLC - Hannibal Power only constructed the General Electric Combustion Turbine (3,544 MMBtu/hr), and therefore, the more stringent H_2SO_4 emission limit of 0.00055 lb/MMBtu without a duct burner was not demonstrated.

Appendix D of 40 CFR Part 75 provides an optional protocol for determining hourly SO_2 emissions and heat input from gas- or oil-fired units without using continuous SO_2 monitors. Mountain State Clean Energy LLC Maidsville elected to establish a more stringent SO_2 emission limit (0.4 gr-s/100 scf) in addition to the optional SO_2 emissions data protocol for its 3,875 MMBtu/hr combustion turbine.

The SO_2 emission factor from AP-42 Table 1.4-2 (0.6 lb/MMscf or 0.0006 lb/MMBtu) is based on a 100% conversion of fuel sulfur to SO_2, and assumes that the sulfur content of natural gas is 2,000 gr/MMscf. However, the SO_2 emission factor can be converted to site-specific sulfur content, which would also result in differences in proposed H_2SO_4 emission rates.

In summary, the available evidence clearly indicates that BACT for H_2SO_4 emissions from the CTGs is use of clean low-sulfur fuel (e.g., natural gas). H_2SO_4 BACT limits need to allow for a reasonable variation in the sulfur content of pipeline natural gas, which is outside the control of the Facility, and SO_2 to SO_3 oxidation from a CO catalyst.

Step 5: Select BACT (H_2SO_4)

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the CTG shall be as follows:

(1) SO_2 and H_2SO_4 from CTG-01 shall be controlled through the use of pipeline-quality natural gas.

(2) SO_2 emissions from CTG-01 shall not exceed 0.0019 lb/MMBtu.

(3) H_2SO_4 emissions from CTG-01 shall not exceed 0.0013 lb/MMBtu.

Pursuant to 326 IAC IDEM, OAQ has determined BACT for H_2SO_4 is the use of pipeline quality natural gas as the sole fuel and H_2SO_4 emission limits of 0.0013 pounds per MMBtu (5.46 lb/hr).

GHG BACT Determination: Combined-Cycle Gas Turbine

Step 1: Identify Potential Control Technologies (GHG)

The principal GHG associated with the CTG is CO_2, with small amounts of CH_4 and N_2O that are incidental to combustion, and trend with the CO_2 emissions. Because these gases differ in their ability to trap heat, 1 ton of CO_2 in the atmosphere has a different effect on global warming than 1 ton of CH_4 or N_2O. For example, pursuant to 40 CFR Part 98, Table A-1, CH_4 and N_2O have 25 times and 298 times, respectively, the global warming potential of CO_2. GHG emissions from the Facility are primarily due to the combustion of natural gas in the CTG. Trace amounts of CH_4 and N_2O will be emitted during combustion in varying quantities depending on operating conditions; however, they will be negligible when compared to CO_2 emissions. Also, there are no known supplemental controls for N_2O or methane emissions from gas-fired units. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions (CO_{2e}).

CO_2 is a product of combustion for any carbon-containing fuel. All fossil fuels contain significant amounts of carbon, including natural gas. During complete combustion, the fuel carbon is oxidized into CO_2 via the following reaction:

$$C + O_2 \rightarrow CO_2$$

Full oxidation of carbon in fuel is desirable because CO, a product of partial combustion, has long been a regulated PSD pollutant, and because full combustion results in more useful energy. In fact, emission control technologies required for CO emissions (oxidation catalysts) increase CO_2 emissions by oxidizing CO to CO_2. Recent BACT determinations for combined-cycle CTG projects have focused on reducing emissions of CO_2 through high-efficiency, power-generation technology and the use of cleaner-burning fuels. There are limited post-combustion options for controlling CO_2. The USEPA has indicated in the document, *PSD and Title V Permitting Guidance for Greenhouse Gases* (2011c), that carbon capture and sequestration CCS should be considered in GHG BACT analyses as a technically feasible, add-on control option for CO_2. Although technically feasible, the technology has not yet been demonstrated at a commercial scale on a combined-cycle CTG project.

(1) Carbon Capture and Storage (CCS);

(2) High Thermal Efficiency Design; and

(3) Low Emission Fuels.

Step 2: Eliminate Technically Infeasible Options (GHG)

(a) Carbon Capture and Storage (CCS)

Carbon Capture and Storage (CCS) involves separation and capture of CO_2 from the combustion exhaust gases using physical or chemical adsorption, pressurization of the captured CO_2, transportation of the captured CO_2 via pipeline, and injection and long-term geologic storage of the captured CO_2. Carbon Capture and Storage (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 combined cycle power plant.

According to the Carbon Capture and Storage (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, Carbon Capture and Storage (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 a natural gas combined cycle power plant. 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 EPA's GHG permitting guidance, a control technology would not be applicable if there are significant differences that preclude successful operations of the control device, such as differences in temperature, pressure, pollutant concentration, or volume of the exhaust stream. Given this significant difference in exhaust CO_2 concentration, it is uncertain that the CO_2 capture technologies currently being investigated for coal-fired power plants can also be applied to natural gas combined cycle power plants.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Carbon Capture and Storage (CCS) is not a technically feasible option for the combined cycle combustion turbine at this source.

(b) High Thermal Efficiency Design

By utilizing a high efficiency natural gas fired CCCT system that meets the basic design purpose of the proposed project, less fossil fuels are required to generate the same desired output of electricity, thereby reducing GHG emissions.

The selected F-class engine has a net design base heat rate of 6.779 Btu/kW-hr (HHV, without duct firing, corrected to ISO conditions). This equates to a heat rate of 7,646 Btu/kW-hr (HHV-net) after accounting for a "reasonable margin of compliance" for the CCCT Facility. SJEC is proposing to install a high efficiency F-class gas turbine to be operated in combined cycle mode.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of high thermal efficiency design is a technically feasible option for the combined cycle combustion turbine at this source.

(c) Low Emission Fuels

Another effective method used to reduce GHG emissions is pollution prevention, or the use of inherently low-emitting fuels. Table 0-2 presents a comparison of the lb/MMBtu of CO_2 of fuel combusted for the primary fossil fuels. This comparison shows that natural gas is easily the lowest CO_2-emitting fossil fuel.

Table 0-2. Comparison of CO_2 Emissions from Different Fuels (lb/MMBtu of CO_2)

Type of Fuel	Emission Factor
Natural Gas (1)	117
Distillate Fuel No. 2 (1)	162
Coal (2)	210
(1) 40 CFR 98; see Appendix C, Table C-2 (2) 40 CFR 98; see Appendix C, Table C-2 for mixed coal (electric power sector)	

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of natural gas as a sole low-emission fuel is a technically feasible option for the combined cycle combustion turbine at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only feasible, applicable and available control technologies identified are:

(1) High Thermal Efficiency Design; and
(2) Low Carbon Fuel.

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) under Process Type Code 15.210 (Large Combustion Turbines - Natural Gas), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Summary of RBLC Database Review - Large Combustion Turbines - Natural Gas - GHG/CO2e

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO_{2e} Requirements
Maple Creek Energy I LLC	Proposed	--	Combined Cycle Combustion Turbine Generator (4,253 MMBtu/hr)	**Control Method:** Use of low-carbon fuel (natural gas) with high-efficiency, combined cycle generation **CO_2e Emission Limit:** 800 lb/MW-hr (gross) corrected to ISO conditions 2,065,094 tons per twelve (12) consecutive month period
Maple Creek Energy I LLC	Existing T153-45909-00056 (06/19/2023)	IN-0365	Combined Cycle Combustion Turbine CTGB (4,200 MMBtu/hr)	**Control Method:** GCP **CO_2e Emission Limit:** 826 lb/MW-hr (gross) 2,292,966 tpy
Maple Creek Energy II LLC	Proposed	--	Combined Cycle Combustion Turbine Generator (4,253 MMBtu/hr)	**Control Method:** Use of low-carbon fuel (natural gas) with high-efficiency, combined cycle generation **CO_2e Emission Limit:** 800 lb/MW-hr (gross) corrected to ISO conditions 2,065,094 tons per twelve (12) consecutive month period
Golden Spread Electric Cooperative, Inc.	109148, PSD1358M2, GHG41M2 (08/14/25)	TX-1000	Simple-Cycle Turbine (2,033 MMBtu/hr)	**Control Method:** Firing pipeline-quality natural gas and use of good combustion practices **No GHG Emission Limit**
Duke Energy, Indiana, Inc. - Cayuga Generating Station	165-47430-00001	IN-0382	Combustion Turbines (4,254 MMBtu/hr)	**Control Method:** Good Combustion Practice and efficient turbine design **CO_2e Emission Limit:** 850 lb/MW-hr per twelve (12) consecutive month period
Wabash Valley Resources, LLC	167-45208-00091 (01/11/2024)	IN-0371	Integrated Gasification Combined Cycle Combustion Turbine (2,292 MMBtu/hr)	**Control Method:** Good Combustion Practices **CO_2e Emission Limit 1:** 110.0 lb/MMBtu (converts to 32.24 lb/MW-hr) **CO_2e Emission Limit 2:** 1,065,780.0 tons of CO_2 per twelve (12) consecutive month period
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Combustion Turbine (4,671 MMBtu/hr)	**Control Method:** Efficient turbine design, only combust pipeline quality natural gas and diesel fuel oil, and oxidation catalyst **CO_2e Emission Limit:** 850 lb CO_2/MW-hr 12-mo rolling avg natural gas
Entergy Texas, Inc. Orange County Advanced Power Station	166032 PSDTX1598 GHGPSDTX210 (03/13/2023)	TX-0939	Combined Cycle Turbines (1,215 MW and 6,762 Btu/hr)	**Control Method:** GCP and clean fuel **CO_2e Emission Limit:** None
Midland Cogeneration Venture Limited Partnership	10-23 (02/01/2023)	MI-0455	EUCTGHRSG1 (4,197.60 MMBtu/hr)	**Control Method:** Low carbon fuel, good combustion practices, energy efficiency measures **CO_2e Emission Limit 1:** 2,375,313 tons/year **CO_2e Emission Limit 2:** 1,000 lb/MW-hr 12-Operating Month Rolling Avg.
Lansing Board of Water and Light - Erickson Station	74-18D (12/20/2022)	MI-0454	EUCTGHRSG1 and EUCTGHRSG2 (667 MMBtu/hr, each)	**Control Method:** Low carbon fuel, good combustion practices, energy efficiency measures **CO_2e Emission Limit 1:** 430,349 tons/year **CO_2e Emission Limit 2:** 1,000 lb/MW-hr 12-Operating Month Rolling Avg.
Lincoln Land Energy	18040008	IL-0133	Combined Cycle	**Control Method:**

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO_{2e} Requirements
Center (A/K/A Emberclear) Lincoln Land Energy Center	(07/29/2022)		Combustion Turbine (3,647 MMBtu/hr)	GCP **CO_2e Emission Limit:** 850 lb/MW-hr (gross)
Alaska Gasline Development Corporation Liquefaction Plant	AQ1539CPT01 (07/07/2022)	AK-0088	(4) Combined Cycle Gas-Fired Turbines (384 MMBtu/hr, each)	**Control Method:** GCP and clean fuel **CO_2e Emission Limit:** 117.1 lb/MMBtu 3-hr (equal to 34.3 lb/MW-hr)
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Combined Cycle Natural Gas-Fired Combustion Turbine Generator with HRSG (3,064 MMBtu/hr)	**Control Method:** Energy efficient measures and use of a low carbon fuel (pipeline quality natural gas) **CO_2e Emission Limit 1:** 2,001,019 tons/year **CO_2e Emission Limit 2:** 806.0 lb/MMBtu-hr (equal to 236.2 lb/MW-hr)
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/03/2022)	MI-0452	Combined Cycle Natural Gas-Fired Combustion Turbine Generator with HRSG (3,064 MMBtu/hr)	**Control Method:** Energy efficient measures and use of a low carbon fuel (pipeline quality natural gas) **CO_2e Emission Limit 1:** 2,001,019 tons/year **CO_2e Emission Limit 2:** 806.0 lb/MMBtu-hr (equal to 236.2 lb/MW-hr)
Magnolia Power LLC- Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Combined Cycle Gas Turbine (5,081 MMBtu/hr)	**Control Method:** Use of gaseous fuel (pipeline-quality natural gas), thermally efficient turbines, and good combustion practices **CO_2e Emission Limit 1:** 2,528,349 tons/year **CO_2e Emission Limit 2:** 875.0 lb/MMBtu-hr (equal to 256.4 lb/MW-hr)
Mountain State Clean Energy LLC Maidsville	R14-0038 (01/05/2022)	WV-0033	Combustion Turbine and Duct Burner (1,275 MW)	**Control Method:** Low Sulfur Fuel **CO_2e Emission Limit 1:** 852 lb/MW-hr gross 12-mth rolling total, **CO_2e Emission Limit 2:** 2,563,571 tons CO2e/year, 1000 lb/MWh gross 12 month rolling avg *There is a unit degradation schedule in the permit that allows an incremental increase of Limit 1 by 0.325%/yr
Shady Hills Energy Center, LLC	1010524-003-AC / PSD-FL-444A (06/07/2021)	FL-0371	Combustion Turbine and HRSG with Duct Firing (3,622 MMBtu/hr)	**Control Method:** Low Emitting Fuel **CO_2e Emission Limit:** 875 lb/MW-hr, 12-mo rolling (primary BACT) 1,000 lb/MW-hr, 12-mo rolling (NSPS TTTT secondary)
Alabama Power Company	503-1001 (11/09/2020)	AL-0328	(2) Combined Cycle Units (744 MW)	**Control Method:** Efficient Design **CO_2e Emission Limit 1:** 1000 lb/MW-hr **CO_2e Emission Limit 2:** 2,445,022 tons/year
FG LA Complex	PSD-LA-812 (01/06/2020)	LA-0364	Natural Gas Cogeneration Units (2,222 MMbtu/hr)	**Control Method:** Use of natural gas as fuel, energy-efficient design options, and operational/maintenance practices **CO_2e Emission Limit 1:** 1,096,666 tons/year
Indeck Niles, LLC	75-16B (11/26/2019)	MI-0445	Natural Gas Combined-cycle Turbine (3,421 MMBtu/hr)	**Control Method:** GCP, pipeline quality natural gas, inlet air conditioning **CO_2e Emission Limit:** 1,911,481 tons/year

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO_{2e} Requirements
				The proposed permit also contains an 802 lb CO2 per MW-hour (lb/MWh) emission limit that serves as BACT due to energy efficiency, which is equivalent to a net heat rate of 6,855 Btu/kW-hr per 2x1 block and is more stringent than the required NSPS limit of the same units.
Thomas Township Energy, LLC	210-18 (8/21/2019)	MI-0442	Natural Gas Combined-cycle Turbine (625 MW, 4,200 MMBtu/hr)	**Control Method:** Energy efficiency measures **CO_2e Emission Limit:** 2,739,722 tons/year
Chickahominy Power LLC	52610-1 (6/24/2019)	VA-0332	Combustion Turbine (4,066 MMBtu/hr)	**Control Method:** Energy efficient combustion practices and low GHG fuels **CO_2e Emission Limit 1:** 812 lb/CO_{2e}/MW-hr 12-mo rolling total **CO_2e Emission Limit 2:** 6,452 Btu/KW-H net HHV Initial Heat Rate Test
Consumers Energy Company / Jackson Generating Station	118-18 (4/02/2019)	MI-0439	Combined-cycle Turbine (420 MW)	**Control Method:** Use of low carbon fuel (natural gas), GCP, and energy efficiency measures **Emission Limit:** 1,000,257 tons/year
Jackson Generation, LLC Jackson Energy Center	17040013 (12/31/2018)	IL-0130	Combined-cycle Turbine (3,864 MMBtu/hr)	**Control Method:** Equipment design and proper operation **Emission Limits:** 4,733,910 tons/year CO_2 emissions shall not exceed 1,000 lb/MW-hr or 1,030 lb/MW-hr of net energy output on a 12-mo rolling average.
ESC Brooke County Power I, LLC Brooke County Power Plant	R14-0035 (9/18/2018)	WV-0032	Combined-cycle Turbine (462.5 MW, 2,737.7 MMBtu/hr)	**Control Method:** None **CO_2e Emission Limit:** 417,382 lb/hr **CO_2e Emission Limit:** 829 lb/MW-hr
CPV Three Rivers, LLC	16060032 (07/30/2018)	IL-0129	Combined-cycle Turbine (3,474 MMBtu/hr)	**Control Method:** None **CO_2e Emission Limit:** 4,026,300 tons/year
DTE Electric Company / Belle River Combined Cycle Power Plant	19-18 (07/16/2018)	MI-0435	Two (2) Combined-Cycle Natural Gas-Fired Combustion Turbine Generators with HRSGs (3,658 MMBtu/hr, each)	**Control Method:** Energy efficiency measures **CO_2e Emission Limit:** 2,042,773 tons/year, each unit 794 lb/MW-hr, each unit
Novi Energy	52588 (04/26/2018)	VA-0328	GE Combustion Turbine (3,482 MMBtu/hr)	**Control Method:** Energy efficient combustion practices and low GHG fuels **CO_2e Emission Limit:** 883 lb CO_{2e}/MW h 12-mo rolling total, 6,745 BTU/KW-h net HHV initial heat rate test
			Siemens Combustion Turbine (3,116 MMBtu/hr)	**Control Method:** Energy efficient combustion practices and low GHG fuels **CO_2e Emission Limit:** 883 lb CO_{2e}/MW-hr 12-mo rolling total, 6,625 BTU/KW-hr net HHV initial heat rate test
Harrison Power	P0122266 (04/19/2018)	OH-0377	MHPS Combustion Turbine (3,231 MMBtu/hr)	**Control Method:** High efficient combustion technology **CO_2e Emission Limit:** 1,000 lb/MW-h with duct burner

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO_{2e} Requirements
				976 lb/MW-h without duct burner * With duct burners: 450 kg per MW-h of gross energy output (1,000 lbs/MW-h) on a 12-operating-month rolling average basis, or, if a petition is granted, CO2 emissions shall not exceed 470 kg per MW-h of net energy output (1,030 lbs/MW-h) on a 12-operating-month rolling average basis. [40 CFR 60.5520(a)-(c) and Table 2 of 40 CFR Part 60, Subpart TTTT] Without duct burners: 976.0 lbs/MW-hr gross energy output at full load ISO conditions when firing natural gas. Gross energy output is defined as the gross power output of the generators before accounting for any balance of plant loads. 2,342,643 tons of CO2e emissions per rolling, 12-month period.
			GE model 7HA.02 Combustion Turbine (3,459.6 MMBtu/hr)	**Control Method:** High efficient combustion technology **CO_2e Emission Limit:** 1,000 lb/MW-hr, with Duct Burner 1012.40 lb/MW-hr without Duct Burner With duct burners: 450 kg per MW-h of gross energy output (1,000 lbs/MW-h) on a 12-operating-month rolling average basis, or, if a petition is granted, CO2 emissions shall not exceed 470 kg per MW-h of net energy output (1,030 lbs/MW-h) on a 12-operating-month rolling average basis. [40 CFR 60.5520(a)-(c) and Table 2 of 40 CFR Part 60, Subpart TTTT] Without duct burners: 1,012.4 lbs/MW-hr gross energy output at full load ISO conditions when firing natural gas. Gross energy output is defined as the gross power output of the generators before accounting for any balance of plant loads. 2,499,820 t/yr of CO2e emissions per rolling, 12-month period.
Harrison County Power Plant	R14-0036 (03/21/2018)	WV-0029	GE 7HA.02 Turbine (3496.20 MMBtu/hr)	**Control Method:** High efficiency combustion practices **CO_2e Emission Limit 1:** 528,543 lb/hr **CO_2e Emission Limit 2:** 2,315,020 tons/yr **CO_2e Emission Limit 3:** 826.0 lb/MW-hr
Long Ridge Energy Generation LLC - Hannibal Power	P0122829 (11/07/2017)	OH-0375	General Electric Combustion Turbine (3,544 MMBtu/hr)	**Control Method:** High efficiency combustion practices **CO_2e Emission Limit 1:** 775 lb/MW-hr gross **CO_2e Emission Limit 2:** 1,915,689 tons/yr
			Siemens Combustion Turbine (3,602 MMBtu/hr)	**Control Method:** High efficiency combustion practices **CO_2e Emission Limit 1:** 1,000 lb/MW-hr gross with duct burner 775 lb/MW-hr gross without duct burner **CO_2e Emission Limit 2:** 1,962,130 tons/yr
			Mitsubishi Combustion Turbine (3,544 MMBtu/hr)	**Control Method:** High efficiency combustion practices **CO_2e Emission Limit 1:** 1,000 lb/MW-hr gross with duct burner 775 lb/MW-hr gross without duct burner **CO_2e Emission Limit 2:** 1,811,235 tons/yr

GHG BACT determinations are expressed in varying units, including mass emission rates (tons or pounds per unit time), pounds of CO_{2e} emitted per megawatt-hour of energy produced (lb CO_{2e} 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 GHG BACT emission limits for natural gas firing are generally for new and clean condition, which only take into account the design margin and do not consider normal degradation. The lowest limit provided in the table is 726 lb/MW-hr, 12-month rolling average. The most recent BACT determination has a GHG limit of 850 lb/MW-hr gross, 12-month rolling average. There are other new and clean permit limits listed in the table above between 812 and 1,000 lb/MW-hr that are limited to full operating load for various CTG technologies. There are also several other projects permitted with annual average GHG limits in units of lb/MW-hr ranging from 850 to 1,000 lb/MW-hr, which take into account all modes of operation.

Facilities constructed after May 23, 2023, are required to meet the requirements under 40 CFR 60, Subpart TTTTa. This NSPS established emission standards based on what the USEPA has determined to be BESR for steam electric generating units and stationary combustion turbine electric generating units. Under this NSPS, for a H-class combustion turbine generator, the standard would be 800 lb/MWh-gross of CO_2, over a 12-month operating average. This represents what USEPA has determined to be a reasonable emissions limit for combined cycle turbine technology.

MCE II is proposing a BACT limit of 800 lb/MW-hr (gross). This proposed limit is consistent with the current NSPS and is lower than or within the range of the other GHG BACT limits presented in the table above.

High-generation efficiency and low-carbon fuels are demonstrated in practice ass being technically feasible, and in combination, represent the most effective GHG control technology demonstrated in practice on combined-cycle CTGs.

MCE II is proposing to use low-carbon fuels with high-efficiency, combined-cycle generation, which is the most stringent GHG control technology available.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for the GHG for the combined cycle combustion turbine:

(1) CO_{2e} emissions from CTG-01 shall not exceed 800 lb/MW-hr (gross) corrected to ISO conditions.

(2) CO_{2e} emissions from CTG-01 shall not exceed 2,065,094 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(3) CO_{2e} emissions from CTG-01 shall be limited through the use of low-carbon fuel (natural gas) with high-efficiency, combined cycle generation.

Summary of Auxiliary Boiler

PM/PM_{10}/$PM_{2.5}$ BACT Determination: Auxiliary Boiler

This section presents the PSD BACT analysis for the auxiliary boiler. The Facility is subject to PSD review for NOx, VOCs, CO, PM/PM_{10}/$PM_{2.5}$, H_2SO_4, and GHGs; therefore, the auxiliary boiler is subject to PSD BACT for these pollutants. The Facility includes a 96 MMBtu/hr auxiliary boiler that will use natural gas as the sole fuel.

Step 1: Identify Potential Control Technologies:

Generally, PM/PM10, and PM2.5 emissions are controlled through one of the following:

(1) Fabric Filter Dust Collectors (Baghouses),
(2) Electrostatic Precipitators (ESP),
(3) Wet Scrubbers,
(4) Cyclones or Multiclones,
(5) Fuel Specification; and
(6) Good Combustion Practices.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

(a) Fabric Filtration

A fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal.

Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99 or 99.9%. The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake.

Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. Typical values of system pressure drop range from about 5 to 20 inches of water.

Fabric filters are used where high efficiency particle collection is required. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation. Important process variables include particle characteristics, gas characteristics, and fabric properties. The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. The major operating feature of fabric filters that distinguishes them from other gas filters is the ability to renew the filtering surface periodically by cleaning. Common furnace filters, high efficiency particulate air (HEPA) filters, high efficiency air filters (HEAFs), and automotive induction air filters are examples of filters that must be discarded after a significant layer of dust accumulates on the surface. These filters are typically made of matted fibers, mounted in supporting frames, and used where dust concentrations are relatively low. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

The fabric filters are susceptible to corrosion and binding by moisture. Appropriate fabrics must be selected for specific process conditions. Accumulations of dust may present fire or explosion hazard. The typical waste stream inlet flow is 100-100,000 scfm (Standard) or 100,000-1,000,00 scfm (Custom). The natural gas fired boilers generate low particulate matter emissions and have large exhaust flow rates, resulting in very low concentration of particulates.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a baghouse is not a technically feasible option for the Auxiliary Boiler (AUX) at this source.

(b) Electrostatic Precipitators

An electrostatic precipitator (ESP) is a particle control device that uses electrical forces to move the particles out of the flowing gas stream and onto collector plates. The particles are given an electrical charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field that forces the charged particles to the walls comes from electrodes maintained at high voltage in the center of the flow lane.
Once the particles are collected on the plates, they must be removed from the plates without re-entraining them into the gas stream. This is usually accomplished by knocking them loose from the plates, allowing the collected layer of particles to slide down into a hopper from which they are evacuated. Some precipitators remove the particles by intermittent or continuous washing with water. ESP control efficiencies can range from 95% to 99.9%.

Gas temperatures may be up to about 1,300 °F (dry) and Lower than 170 - 190 °F (wet). The typical waste stream inlet flow is 1,000 - 100,000 scfm (Wire-Pipe) and 100,000 - 1,000,000 scfm (Wire-Plate). Dry ESP efficiency varies significantly with dust resistivity. Air leakage and acid condensation may cause corrosion. ESPs are not generally suitable for highly variable processes. Equipment footprint is often substantial. Natural gas-fired auxiliary boilers generate low particulate emissions and have large exhaust flowrates, resulting in very low concentrations of particulates. Electrostatic precipitator (ESP) would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of an electrostatic precipitator is not a technically feasible option for the Auxiliary Boiler (AUX) at this source.

(c) Wet scrubbers

A wet scrubber is an air pollution control device that removes particulate matter from waste gas streams primarily through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. The liquid containing the pollutant is then collected for disposal. There are numerous types of wet scrubbers that remove particulate matter. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream. In general, collection efficiency decreases as the particulate matter size decreases. Collection efficiencies also vary with scrubber type.

Collection efficiencies range from greater than 99% for venturi scrubbers to 40-60% (or lower) for simple spray towers. Wet scrubbers are smaller and more compact than baghouses or ESPs. They have lower capital costs and comparable operation and maintenance (O&M) costs. Wet scrubbers are particularly useful in the removal of particulate matter with the following characteristics:

(1) Sticky and/or hygroscopic materials (materials that readily absorb water);
(2) Combustible, corrosive and explosive materials;
(3) Particles which are difficult to remove in their dry form;
(4) PM in the presence of soluble gases; and
(5) PM in waste gas streams with high moisture content.

The primary disadvantage of wet scrubbers is that increased collection efficiency comes at the cost of increased pressure drop across the control system. Another disadvantage is that they are limited to lower waste gas flow rates and temperatures than ESPs or baghouses. Current wet scrubber designs accommodate air flow rates over 100,000 actual cubic feet per minute and temperatures of up to 750°F. Lastly, downstream corrosion or plume visibility problems can result unless the added moisture is removed from the gas stream.

Gas temperatures are between 40 to 750 °F. The typical waste stream inlet flow is 500 - 100,000 scfm (units in parallel can operate at greater flow rates). Effluent wastewater stream may require treatment. Sludge disposal may be costly. Wet scrubbers are particularly susceptible to corrosion. Natural gas-fired auxiliary boilers generate low particulate emissions and have large exhaust flowrates, resulting in very low concentrations of particulates. A wet scrubber would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a wet scrubber is not a technically feasible option for the Auxiliary Boiler (AUX) at this source.

(d) Cyclones:

Cyclones are simple mechanical devices commonly used to remove relatively large particles from gas streams. In industrial applications, cyclones are often used as precleaners for the more sophisticated air pollution control equipment such as ESPs or baghouses. Cyclones are less efficient than wet scrubbers, baghouses, or ESPs.

Cyclones used as pre-cleaners are often designed to remove more than 80% of the particles that are greater than 20 microns in diameter. Smaller particles that escape the cyclone can then be collected by more efficient control equipment. This control technology may be more commonly used in industrial sites that generate a considerable amount of particulate matter, such as lumber companies, feed mills, cement plants, and smelters.

The gas temperature is about 1,000°F. The typical waste stream inlet flow is between 1.1 - 63,500 scfm (single) and up to 106,000 scfm (in parallel). Cyclones typically exhibit lower efficiencies when collecting smaller particles. High-efficiency units may require substantial pressure drop. Natural gas-fired auxiliary boilers generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. Cyclones would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a cyclone is not a technically feasible option for the Auxiliary Boiler (AUX) at this source.

(e) Fuel Specifications

Combusting only **c**lean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating PM and PM_{10} emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Fuel Specifications is a technically feasible option for the Auxiliary Boiler (AUX) at this source.

(f) Good Combustion Practices

Good combustion practices as well as operation and maintenance of the Auxiliary Boilers to keep them in good working order per the manufacturer's specifications will minimize PM and PM_{10}, and $PM_{2.5}$ emissions.

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 Boiler (AUX) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of PM and PM_{10}, and $PM_{2.5}$ resulting from the operation of the Auxiliary Boiler (AUX).

(1) Fuel Specifications; and
(2) 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) under Process Type Code 13.310 (Commercial/Institutional-Size Boilers/Furnaces <100 MMBtu/hr - Natural Gas), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Summary of RBLC Database Review - Auxiliary Boilers - Natural Gas

Facility	Permit Number & Date	RBLC ID #	Emission Unit	PM/PM10/PM2.5 Requirements
Maple Creek Energy I LLC	Proposed	--	Natural Gas-Fired Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Use of pipeline-quality natural gas and good combustion practices **Filterable PM Emission Limit:** 0.0019 lb/MMBtu, **PM_{10}/$PM_{2.5}$ Emission Limit:**

Facility	Permit Number & Date	RBLC ID #	Emission Unit	PM/PM10/PM2.5 Requirements
				0.0075 lb/MMBtu,
Maple Creek Energy I LLC	Existing T153-45909-00056 (06/19/2023)	IN-0365	Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Pipeline quality fuel **PM/PM$_{10}$/PM$_{2.5}$ Emission Limit:** 0.0075 lb/MMBtu
Maple Creek Energy II LLC	Proposed	--	Natural Gas-Fired Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Use of pipeline-quality natural gas and good combustion practices **PM Emission Limit:** 0.0019 lb/MMBtu, **PM$_{10}$/PM$_{2.5}$ Emission Limit:** 0.0075 lb/MMBtu,
Duke Energy, Indiana, Inc. - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	Auxiliary Boiler (225 MMBtu/hr)	**Control Method:** Good combustion practices and combusting pipeline-quality natural gas **PM Emission Limit:** 0.0019 lb/MMBtu
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Natural Gas Auxiliary Boiler (100 MMBtu/hr)	**Control Method:** Pipeline quality natural gas **PM/PM$_{10}$/PM$_{2.5}$ Emission Limit:** 0.01 lb/MMBtu
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	Auxiliary Boiler (80 MMBtu/hr)	**Control Method:** Good combustion practices **PM Emission Limit:** 0.0019 lb/MMBtu **PM$_{10}$/PM$_{2.5}$ Emission Limit:** 0.0075 lb/MMBtu
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Auxiliary Boiler (61.50 MMBtu/hr)	**Control Method:** Good combustion practices **PM Emission Limit:** 0.005 lb/MMBtu hourly **PM$_{10}$/PM$_{2.5}$ Emission Limit:** 0.46 lb/hr *(converts to 0.0075 lb/MMBtu)*
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/23/2022)	MI-0542	Auxiliary Boiler (61.50 MMBtu/hr)	**Control Method:** Good combustion practices **PM Emission Limit:** 0.005 lb/MMBtu hourly **PM$_{10}$/PM$_{2.5}$ Emission Limit:** 0.46 lb/hr *(converts to 0.0075 lb/MMBtu)*
Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Auxiliary Boiler (80 MMBtu/hr)	**Control Method:** Exclusive combustion of natural gas and good combustion practices **PM$_{10}$/PM$_{2.5}$ Emission Limit:** 0.0074 lb/MMBtu hourly
Shady Hills Combined Cycle Facility	1010524-003-AC (PSD-FL-444A) (06/07/2021)	FL-0371	Auxiliary Boiler (60 MMBtu/hr)	**Control Method:** Clean Fuels, Sulfur content less than 1.4 gr s per 100 scf **PM/PM$_{10}$/PM$_{2.5}$ Emission Limit:** 1.4 gr s/100 scf *(0.0019 lb/MMBtu)* 20% opacity
Alabama Power Company - Plant Barry	503-1001 (11/09/2020)	AL-0328	Auxiliary Boiler (90.50 MMBtu/hr)	**Control Method:** None **PM$_{10}$/PM$_{2.5}$ Emission Limit:** 0.0075 lb/MMBtu
Indeck Niles, LLC	75-16B (11/26/2019)	MI-0445	Auxiliary Boiler (182 MMBtu/hr)	**Control Method:** Good combustion practices **PM Emission Limit:** 0.005 lb/MMBtu hourly **PM$_{10}$/PM$_{2.5}$ Emission Limit:** 1.36 lb/hr *(converts to 0.0075 lb/MMBtu)*

Facility	Permit Number & Date	RBLC ID #	Emission Unit	PM/PM10/PM2.5 Requirements
Thomas Township Energy, LLC	210-18 (08/21/2019)	MI-0442	Auxiliary Boiler (80 MMBtu/hr)	**Control Method:** Low Sulfur Fuel and GCP **PM Emission Limit:** 1.9 lb/MMScf hourly *(converts to 0.0019 lb/MMBtu)* **$PM_{10}/PM_{2.5}$ Emission Limit:** 7.60 lb/MMscf hourly *(converts to 0.0075 lb/MMBtu)*
Jackson Generation, LLC	17040013 (12/31/2018)	IL-0130	Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Good combustion practices **PM Emission Limit:** 0.0019 lb/MMBtu **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.0075 lb/MMBtu
ESC Brooke County Power I, LLC Brooke County Power Plant	R14-0035 (09/18/2018)	WV-0032	Auxiliary Boiler (111.9 MMBtu/hr)	**Control Method:** Use of natural gas, good combustion practices **$PM_{2.5}$ Emission Limit:** 0.87 lb/hr, 1.99 tons/year, 0.008 lb/MMBtu
CPV Three Rivers, LLC	16060032 (07/30/2018)	IL-0129	Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Good combustion practices **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.0075 lb/MMBtu 0.72 lb/hr 1.44 tons/year
Belle River Combined Cycle Power Plant	19-18 (07/16/2018)	MI-0435	Auxiliary Boiler (99.9 MMBtu/hr)	**Control Method:** Good combustion practices, low sulfur fuel **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.0070 lb/MMBtu hourly 0.70 lb/hr
Harrison Power	P0122266 (04/19/2018)	OH-0377	Auxiliary Boiler B001 (44.55 MMBtu/hr)	**Control Method:** Pipeline quality natural gas **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.33 lb/hr, 0.18 tpy, 0.0075 lb/MMBtu
			Auxiliary Boiler B002 (80 MMBtu/hr)	**Control Method:** Pipeline quality natural gas **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.48 lb/hr, 0.26 tpy, 0.0060 lb/MMBtu (condensable only)
Harrison County Power Plant	R14-0036 (03/27/2018)	WV-0029	Auxiliary Boiler (77.80 MMBtu/hr)	**Control Method:** Use of natural gas and good combustion practices **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.60 lb/hr, 1.38 tons/year, 0.0080 lb/MMBtu
Renovo Energy Center LLC / Renovo PLT	18-00033A (01/26/2018)	PA-0316	Auxiliary Boiler (13.56 MMBtu/hr)	**Control Method:** None **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.11 tons/year, 0.0019 lb/MMBtu
Dania Beach Energy Center	0110037-017-AC (12/04/2017)	FL-0363	Auxiliary Boiler (99.80 MMBtu/hr)	**Control Method:** Clean fuels May only fire natural gas with sulfur content less than 2 grains per 100 scf. This limits SO2, SAM, PM, PM10, and PM2.5.
Long Ridge Energy Generation LLC - Hannibal Power	P0122829 (11/07/2017)	OH-0375	Auxiliary Boiler (26.8 MMBtu/hr)	**Control Method:** Low sulfur fuel **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.01 lb/MMBtu 0.27 lb/hr 0.67 tons/yr

Facility	Permit Number & Date	RBLC ID #	Emission Unit	PM/PM10/PM2.5 Requirements
Oregon Energy Center	P0121049 (09/27/2017)	OH-0372	Auxiliary Boiler (37.8 MMBtu/hr)	**Control Method:** Low sulfur fuel **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.0080 lb/MMBtu 0.30 lb/hr 0.30 tons/yr
Trumbull Energy Center	P0122331 (09/07/2017)	OH-0370	Auxiliary Boiler (37.8 MMBtu/hr)	**Control Method:** Low sulfur fuel **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.0080 lb/MMBtu 0.30 lb/hr 0.30 tons/yr
Holland Board of Public Works - East 5th Street	107-13C (12/05/2016)	MI-0424	Auxiliary Boiler (83.5 MMBtu/hr)	**Control Method:** Good combustion practices **PM Emission Limit:** 0.0018 lb/MMBtu **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.0070 lb/MMBtu
South Field Energy LLC	P0119495 (09/23/2016)	OH-0367	Auxiliary Boiler (99.0 MMBtu/hr)	**Control Method:** Good combustion practices and natural gas/ULSD **$PM_{10}/PM_{2.5}$ Emission Limit:** 5.94 lb/hr 5.69 tons/yr 0.008 lb/MMBtu (natural gas) 0.060 lb/MMBtu (diesel)
CPV Fairview Energy Center	11-00536A (09/02/2016)	PA-0310	Auxiliary Boiler (92.40 MMBtu/hr)	**Control Method:** ULSD and good combustion practices **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.0070 lb/MMBtu 1.29 tons/yr

The $PM/PM_{10}/PM_{2.5}$ BACT precedents range from 0.001 to 0.008 lb/MMBtu, with the most recent Indiana determinations being 0.0019 lb of PM per MMBtu of natural gas for Duke Energy, Indiana, Inc. - Cayuga Generating Station and 0.0075 lb of $PM/PM_{10}/PM_{2.5}$ per MMBtu of natural gas for Maple Creek Energy I, LLC. Particulate emission limits are mostly based on AP-42 emission factors (Table 1.4-2 Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion), and variations in $PM/PM_{10}/PM_{2.5}$ BACT emission limits depend on whether the facility is limiting condensable particulates, filterable particulates, or combined condensable and filterable particulates.

Several facilities, such as Lincoln Land Energy Center, Thomas Township Energy, LLC, and Jackson Generation, LLC, utilize separate limitations for filterable PM (0.0019 lb/MMBtu) and total condensable and filterable emission factor for the PM_{10} and $PM_{2.5}$ emission limit (0.0075 lb/MMBtu). Other sources, like CPV Three Rivers, LLC, Belle River Combined Cycle Power Plant, and Harrison County Power Plant utilize the total filterable and condensable particulates emission factor in one limitation for $PM/PM_{10}/PM_{2.5}$ (0.0075 lb/MMBtu). Harrison Power in Ohio proposed an emission limit based the total particulate AP-42 emission factor (0.0075 lb/MMBtu) for the 44.55 MMBtu/hr Auxiliary Boiler (B001), and proposed the AP-42 condensable emission factor (0.0060 lb/MMBtu) for particulate emissions from the 80 MMBtu/hr Auxiliary Boiler (B002). Renovo Energy Center, LLC, which has cancelled construction, proposed an emission limit on the filterable emission factor of 0.0019 lb/MMBtu for PM_{10} and $PM_{2.5}$.

The proposed BACT limit is 0.0019 lb/MMBtu for PM and 0.0075 lb/MMBtu for $PM_{10}/PM_{2.5}$ for the Facility's auxiliary boiler. These limits are based on the AP-42, Table 1.4-2 emission factors for PM (filterable), and PM10/PM2.5 (filterable and condensable) and is consistent with this range of the precedents listed in Appendix C, Table C-7 and with the most recently approved BACT 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 natural gas-fired auxiliary boiler (AUX) shall be as follows:

(1) PM, PM_{10}, and $PM_{2.5}$ emissions shall be controlled through the use of pipeline-quality natural gas.

(2) PM, PM_{10}, and $PM_{2.5}$ emissions shall be controlled through the use of good combustion practices.

(3) Filterable PM emissions from the natural gas-fired auxiliary boiler (AUX) shall not exceed 0.0019 lb/MMBtu.

(4) PM_{10} emissions from the natural gas-fired auxiliary boiler (AUX) shall not exceed 0.0075 lb/MMBtu.

(5) $PM_{2.5}$ emissions from the natural gas-fired auxiliary boiler (AUX) shall not exceed 0.0075 lb/MMBtu.

NOx BACT Determination: Auxiliary Boiler

Step 1: Identify Potential Control Technologies

The nitrogen oxide (NOx) emissions can be controlled by the following methods:

(a) Selective Catalytic Reduction (SCR)
(b) Selective Non-Catalytic Reduction (SNCR)
(c) SCONOx Catalytic Absorption System
(d) Ultra-Low NOx Burners (LNB)
(e) Ultra-Low NOx Burners (LNB) with Flue Gas Recirculation (FGR)

Add-on control technologies and combustion control approaches are discussed below.

Step 2: Eliminate Technically Infeasible Options

(a) Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to water and N_2. Under optimal conditions, SCR has a removal efficiency up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

The most important factor affecting SCR efficiency is temperature. SCR can operate in a flue gas window ranging from 480°F to 800°F, although the optimum temperature range depends on the type of catalyst and the flue gas composition. In this particular service, the minimum target temperature is approximately 750 F. Temperature below the optimum, decrease catalyst activity and allow NH3 to slip through; above the optimum range, ammonia will oxidize to form additional NOx. SCR efficiency is also largely dependent on the stoichiometric molar ratio of NH3:NOx; variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%.

Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a soot blower.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective catalytic reduction (SCR) is a technically feasible option for the Auxiliary Boiler at this source.

(b) Selective Non-Catalytic Reduction (SNCR)

With selective non-catalytic reduction (SNCR), NO_X is selectively removed by the injection of ammonia or urea into the flue gas at an appropriate temperature window of 1600°F to 2100°F and without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the NO_X to molecular nitrogen and water. This approach avoids the problem related to catalyst fouling but the temperature window and reagent mixing residence time is critical for conducting the necessary chemical reaction. At the proper temperature, urea decomposes to produce ammonia which is responsible for NO_X reduction. At a higher temperature, the rate of a competing reaction for the direct oxidation of ammonia that actually forms NO_x becomes significant. At a lower temperature, the rates of NO_X reduction reactions become too slow resulting in urea slip (i.e. emissions of unreacted urea).

Optimal implementation of SNCR requires the employment of an injection system that can accomplish thorough reagent/gas mixing within the temperature window while accommodating spatial and production rate temperature variability in the gas stream. The attainment of maximum NO_x control performance therefore requires that the source exhibit a favorable opportunity for the application of this technology relative to the location of the reaction temperature range.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective non-catalytic reduction (SNCR) is a technically feasible option for the Auxiliary Boiler at this source.

(c) Low NOx Burner (LNB)

Using LNB can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs include staged air, and fuel, as well as other methods that effectively lower the flame temperature. In the drive to reduce NOx emissions, NOx reduction techniques were implemented to lower peak flame temperature.

The ULNBs are specially designed pieces of combustion equipment that reduce NOx formation through careful control of the fuel-air mixture during combustion. In a staged air combustion LNB, either air or fuel is added downstream of the primary combustion zone. Depending on which of these NOx reduction techniques are used, LNBs with staged combustion are subdivided into staged air burners and staged fuel burners.

Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one burner installation to another. Typical reductions range from 40% - 50% but under certain conditions, higher reductions are possible especially when another NOx reduction technique is used in conjunction with LNBs.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of low NOx burners is a technically feasible option for the Auxiliary Boiler at this source.

(d) SCONOx Catalytic Absorption System

SCONOx Catalytic Absorption System utilizes a single catalyst to remove NO_X, CO, and VOC through oxidation. Now operating as EmeraChem, the current version of the technology is now marketed as EM_X. The Operating Temperature ranges from 300 - 700 °F. The $SCONO_X$ Catalyst is sensitive to contamination by sulfur, so it must be used in conjunction with the $SCOSO_X$ catalyst, which favors sulfur compound absorption. This control technology is not listed in RBLC for the control of NO_X emissions from auxiliary boilers. Technology has only been demonstrated on units ranging from 5 to 45 MW.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective SCONOx Catalytic Absorption System is not a technically feasible option for the Auxiliary Boiler at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Selective Catalytic Reduction — (50-90% NOx Reduction)
(2) Selective Non-catalytic Reduction — (40-60% NOx Reduction)
(3) Low NOx Burner (LNB) — (40%-50% NOx Reduction)
(4) Low NOx Burner (LNB) w/ FGR — (50%-70% NOx Reduction)

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed NOx BACT determination along with the existing NOx BACT determinations for similar plants. All data in the table is based on the information obtained from the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

Summary of RBLC Database Review - Auxiliary Boilers - Natural Gas

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Emission Limits
Maple Creek Energy I LLC	Proposed	--	Natural Gas-Fired Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Ultra-Low-NOx Burner **NOx Emission Limit:** 0.011 lb/MMBtu 2,000 hours of operation per twelve (12) consecutive month period
Maple Creek Energy I LLC	Existing T153-45909-00056 (06/19/2023)	IN-0365	Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Low NOx Burner **NOx Emission Limit:** 0.037 lb/MMBtu
Maple Creek Energy II LLC	Proposed	--	Natural Gas-Fired Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Low-NOx Burner **NOx Emission Limit:** 0.011 lb/MMBtu
Wabash Valley Resources, LLC	167-45208-00091 (01/11/2024)	IN-0371	Auxiliary Boiler (20 MMbtu/hr)	**Control Method:** Low NOx Burners and Good Combustion Practices **NOx Emission Limit:** 35 lb/MMscf (approx. 0.034 lb/MMBtu)
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Natural Gas Auxiliary Boiler (100 MMBtu/hr)	**Control Method:** Ultra-low NOX burners and flue gas recirculation **NOx Emission Limit:** 0.011 lb/MMBtu

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Emission Limits
LBWL - Erickson Station	74-18D (12/20/2022)	MI-0454	NG-Fired Auxiliary Boiler (50 MMbtu/hr)	**Control Method:** Low NOx Burner or Flue Gas Recirculation, good combustion practices **NOx Emission Limit:** 30.0 ppm @ 3% O_2 hourly (approx. 0.035 lb/MMBtu)
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	Auxiliary Boiler (80 MMBtu/hr)	**Control Method:** Ultra-low NOx Burner and Flue Gas Recirculation, air preheater, automated combustion management system, with an oxygen trim system and an automated water blowdown system **NOx Emission Limit:** 0.01 lb/MMBtu
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Auxiliary Boiler (61.50 MMBtu/hr)	**Control Method:** Low NOx Burner/Flue Gas Recirculation, good combustion practices **NOx Emission Limit:** 0.04 lb/MMBtu
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/23/2022)	MI-0542	Auxiliary Boiler (61.50 MMBtu/hr)	**Control Method:** Low NOx Burner/Flue Gas Recirculation, good combustion practices **NOx Emission Limit:** 0.04 lb/MMBtu
Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Auxiliary Boiler (80 MMBtu/hr)	**Control Method:** Ultra-low NOx Burners and good combustion practices **NOx Emission Limit:** 0.01 lb/MMBtu
Shady Hills Combined Cycle Facility	1010524-003-AC (PSD-FL-444A) (06/07/2021)	FL-0371	Auxiliary Boiler (60 MMBtu/hr)	**Control Method:** Low NOx Burners **NOx Emission Limit:** 0.05 lb/MMBtu
Alabama Power Company -Plant Barry	503-1001 (11/09/2020)	AL-0328	Auxiliary Boiler (90.50 MMBtu/hr)	**Control Method:** None **NOx Emission Limit:** 0.011 lb/MMBtu
Indeck Niles, LLC	75-16B (11/26/2019)	MI-0445	Auxiliary Boiler (182 MMBtu/hr)	**Control Method:** Low NOx burners/flue gas recirculation and good combustion practices **NOx Emission Limit:** 0.04 lb/MMBtu
Thomas Township Energy, LLC	210-18 (08/21/2019)	MI-0442	Auxiliary Boiler (80 MMBtu/hr)	**Control Method:** Good combustion practices and low NOx burners **NOx Emission Limit:** 0.036 lb/MMBtu
Jackson Generation, LLC	17040013 (12/31/2018)	IL-0130	Auxiliary Boiler (96 MMBtu/hr)	**LAER** **Control Method:** Ultra Low-NOx burners and flue gas recirculation air preheater, automated combustion management systems, automated water blowdown, good combustion practices **NOx Emission Limit:** 0.0100 lb/MMBtu
ESC Brooke County Power I, LLC Brooke County Power Plant	R14-0035 (09/18/2018)	WV-0032	Auxiliary Boiler (111.9 MMBtu/hr)	**Control Method:** Low-NOx burners, good combustion practices **NOx Emission Limit:** 1.23 lb/hr 2.82 tons/year 0.0110 lb/MMBtu
APV Renaissance Partners Renaissance Energy	30-00235A (08/27/2018)	PA-0319	Auxiliary Boiler (88 MMBtu/hr)	**LAER** **Control Method:** Low-NOx burners, flue gas recirculation, good

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Emission Limits
Center				combustion practices, proper operation and maintenance **NOx Emission Limit:** 0.020 lb/MMBtu
CPV Three Rivers, LLC	16060032 (07/30/2018)	IL-0129	Auxiliary Boiler (96 MMBtu/hr)	**LAER** **Control Method:** Ultra Low-NOx burners, flue gas recirculation, air preheater, automated combustion management system with O_2 trim system and automated water blowdown, and good combustion practices **NOx Emission Limit:** 0.0110 lb/MMBtu 1.1 lb/hr 2.2 tons/year
Belle River Combined Cycle Power Plant	19-18 (07/16/2018)	MI-0435	Auxiliary Boiler (99.9 MMBtu/hr)	**Control Method:** Low-NOx burners/Flue gas recirculation **NOx Emission Limit:** 0.036 lb/MMBtu 3.6 lb/hr
Harrison Power	P0122266 (04/19/2018)	OH-0377	Auxiliary Boiler B001 (44.55 MMBtu/hr)	**Control Method:** Low-NOx burners, good combustion practices NOx **Emission Limit:** 1.56 lb/hr 0.84 tons/year 0.035 lb/MMBtu
			Auxiliary Boiler B002 (80 MMBtu/hr)	**Control Method:** Low-NOx burners, good combustion practices NOx **Emission Limit:** 2.19 lb/hr 1.18 tons/year 0.027 lb/MMBtu
Harrison County Power Plant	R14-0036 (03/27/2018)	WV-0029	Auxiliary Boiler (77.80 MMBtu/hr) (Annual Emissions based on 4,600 hrs/yr)	**Control Method:** Low-NOx burners, GCP, FGR **NOx Emission Limit:** 0.86 lb/hr 1.96 tons/year 0.011 lb/MMBtu
Renovo Energy Center LLC / Renovo PLT	18-00033A (01/26/2018)	PA-0316	Auxiliary Boiler (13.56 MMBtu/hr)	**LAER** **Control Method:** Ultra low-NOx burners and flue gas recirculation, operated in accordance with the manufacturer's specifications, and good operating practices **NOx Emission Limit:** 0.65 tons/year 0.011 lb/MMBtu
Long Ridge Energy Generation LLC - Hannibal Power	P0122829 (11/07/2017)	OH-0375	Auxiliary Boiler (26.8 MMBtu/hr)	**Control Method:** Flue gas recirculation and low NOx burner **NOx Emission Limit:** 0.29 lb/hr 0.74 tons/year 0.011 lb/MMBtu
Oregon Energy Center	P0121049 (09/27/2017)	OH-0372	Auxiliary Boiler (37.8 MMBtu/hr)	**Control Method:** Flue gas recirculation and low NOx burners **NOx Emission Limit:** 0.76 lb/hr 0.76 tons/year 0.02 lb/MMBtu
Trumbull Energy Center	P0122331 (09/07/2017)	OH-0370	Auxiliary Boiler (37.8 MMBtu/hr)	**Control Method:** Flue gas recirculation and low NOx burners **NOx Emission Limit:** 0.76 lb/hr 0.76 tons/year 0.02 lb/MMBtu

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Emission Limits
Holland Board of Public Works - East 5th Street	107-13C (12/05/2016)	MI-0424	Auxiliary Boiler (83.5 MMBtu/hr)	**Control Method:** Low-NOx burner/Internal flue gas recirculation and good combustion practices **NOx Emission Limit:** 0.050 lb/MMBtu
South Field Energy LLC	P0119495 (09/23/2016)	OH-0367	Auxiliary Boiler (99.0 MMBtu/hr)	**Control Method:** Low-NOx burners, GCP, FGR, NG/ultra low sulfur diesel NOx **Emission Limit:** 9.9 lb/hr 10.65 tons/year 0.02 lb/MMBtu (NG) 0.10 lb/MMbtu (diesel)
CPV Fairview Energy Center	11-00536A (09/02/2016)	PA-0310	Auxiliary Boiler (92.40 MMBtu/hr)	**LAER** **Control Method:** Ultra low-NOx burners, flue gas recirculation, good combustion practices **NOx Emission Limit:** 0.0110 lb/MMBtu 2.03 tons/year

For NOx, the levels of control range from 0.01 to 0.05 lb/MMBtu. While some of the auxiliary boilers have been approved with ultra-low NOx burners (0.01 lb/MMBtu), several of the boilers permitted with ultra-low NOx burners, including Jackson Generation (Will County, IL), Renaissance Energy Center (Greene County, PA), CPV Three Rivers (Grundy County, IL), Renovo Energy Center (Clinton County, PA), and Fairview Energy Center (Cambria County, PA), were located in non-attainment areas for O_3 and were subject to LAER.

Several sources like Nemadji Trail Energy Center, Lincoln Land Energy Center, Harrison County Power Plant, and Long Ridge Energy Generation (Hannibal Power), use flue gas recirculation as BACT in addition to the more stringent emission limit 0.01 lb/MMBtu and either low-NOx or ultra-low NOx burners. Other sources use the 0.01 lb/MMBtu emission limit as BACT without flue gas recirculation, but with ultra-low NOx burners (Magnolia Power Generating Station) or low-NOx burners (Brooke County Power Plant).

The two most recent projects in Indiana, Wabash Valley Resources and Maple Creek Energy LLC have BACT determinations of 0.037 lb NOx/MMBtu. Also, while not yet an RBLC entry, there was a combined cycle facility in Ohio (Chestnut Run Energy) with a permit issued in the last month that also has a BACT determination of 0.037 lb/MMBtu for NOx. Based on a review of the available information from recently permitted projects, the Best Available Control Technology is a low-NOx Burner in combination with a 0.011 lb/MMBtu emission limit.

<u>Step 5: Select BACT</u>

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler (AUX) shall be as follows:

(1) NOx emissions from the natural gas-fired auxiliary boiler (AUX) shall not exceed 0.011 lb/MMBtu.

(2) NOx emissions from the natural gas-fired auxiliary boiler (AUX) shall be controlled by an Ultra-Low NOx Burner.

(3) The auxiliary boiler (AUX) shall not exceed 2,000 hours of operation per twelve (12) consecutive month period.

CO BACT Determination: Auxiliary Boiler

Step 1: Identify Potential Control Technologies (CO)

Emissions of carbon monoxide (CO) are generally controlled by oxidation. Oxidation technologies include regenerative thermal oxidation, catalytic oxidation, and flares.

(a) Regenerative thermal oxidation;
(b) Recuperative thermal oxidizer;
(c) Catalytic oxidation;
(d) Good Combustion Controls; and
(e) Flares.

If add-on control technology is not feasible, an alternate method of control may be implemented.

Step 2: Eliminate Technically Infeasible Options (CO)

(a) 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, nevertheless it is also considered as a technology for controlling VOC emissions. Upon passing through the flame, the waste gas containing VOC is heated. The mixture continues to react as it flows through the combustion chamber.

The required level of 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 from properly operated natural gas combustion units without the use of a catalyst.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is not a technically feasible option for the Auxiliary Boiler at this source.

(b) 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 the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a recuperative thermal oxidizer is not a technically feasible option for the Auxiliary Boiler at this source.

(c) Catalytic Oxidizers

Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling CO emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without 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.

Similar to thermal incineration, 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.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is a technically feasible option for Auxiliary Boiler at this source.

(d) Flare

Although the CO 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 NO_x. Flares have not been utilized or demonstrated as a control device for CO from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a flare is not a technically feasible option for the Auxiliary Boiler at this source

(e) Good Combustion Controls

Good combustion controls is a continued operation of the boiler at the appropriate oxygen range and temperature to promote complete combustion and minimize CO formation. Because CO is essentially a byproduct of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of CO emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. CO emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Controls is a technically feasible option for the Auxiliary Boiler at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness (CO)

(1) Oxidation Catalyst - (50-90% destruction efficiency)
(2) Combustion Control

Step 4: Evaluate Top Control Alternatives (CO)

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) under Process Type Code 13.310 (Commercial/Institutional-Size Boilers/Furnaces <100 MMBtu/hr - Natural Gas), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Summary of RBLC Database Review - Auxiliary Boilers - Natural Gas

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO Emission Limits
Maple Creek Energy I LLC	Proposed	--	Natural Gas-Fired Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 0.037 lb/MMBtu
Duke Energy, Indiana, Inc. - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	Auxiliary Boiler (225 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 0.037 lb/MMBtu
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Natural Gas Auxiliary Boiler (100 MMBtu/hr)	**Control Method:** Oxidation catalyst **CO Emission Limit:** 0.037 lb/MMBtu
Maple Creek Energy LLC	T153-45909-00056 (06/19/2023)	IN-0365	Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 0.037 lb/MMBtu
LBWL - Erickson Station	74-18D (12/20/2022)	MI-0454	NG-Fired Auxiliary Boiler (50 MMbtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 50.0 ppm ppmvd @3% O_2

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO Emission Limits
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	Auxiliary Boiler (80 MMBtu/hr)	**Control Method:** Good burner design and good combustion practices **CO Emission Limit:** 0.037 lb/MMBtu
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Auxiliary Boiler (61.50 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 0.08 lb/MMBtu
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/23/2022)	MI-0542	Auxiliary Boiler (61.50 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 0.08 lb/MMBtu
Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Auxiliary Boiler (80 MMBtu/hr)	**Control Method:** Good combustion practices, compliance with 40 CFR 63 Subpart DDDDD **CO Emission Limit:** 0.05 lb/MMBtu
Shady Hills Combined Cycle Facility	1010524-003-AC (PSD-FL-444A) (06/07/2021)	FL-0371	Auxiliary Boiler (60 MMBtu/hr)	**Control Method:** Good combustion practices and low-NOx burners **CO Emission Limit:** 0.08 lb/MMBtu
Alabama Power Company -Plant Barry	503-1001 (11/09/2020)	AL-0328	Auxiliary Boiler (90.50 MMBtu/hr)	**Control Method:** None **CO Emission Limit:** 0.037 lb/MMBtu
Indeck Niles, LLC	75-16B (11/26/2019)	MI-0445	Auxiliary Boiler (182 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 0.04 lb/MMBtu
Thomas Township Energy, LLC	210-18 (08/21/2019)	MI-0442	Auxiliary Boiler (80 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 0.037 lb/MMBtu
Jackson Generation, LLC	17040013 (12/31/2018)	IL-0130	Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 0.037 lbs/MMBtu
ESC Brooke County Power I, LLC Brooke County Power Plant	R14-0035 (09/18/2018)	WV-0032	Auxiliary Boiler (111.9 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 4.14 lb/hr 9.47 tons/year 0.037 lb/MMbtu
APV Renaissance Partners Renaissance Energy Center	30-00235A (08/27/2018)	PA-0319	Auxiliary Boiler (88 MMBtu/hr)	**Control Method:** Low NOx burners, flue gas recirculation, good combustion practices, proper operation and maintenance **CO Emission Limit:** 0.0550 lb/MMbtu
CPV Three Rivers, LLC	16060032 (07/30/2018)	IL-0129	Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 0.0370 lb/MMbtu 3.6 lb/hr 7.2 tons/year
Belle River Combined Cycle Power Plant	19-18 (07/16/2018)	MI-0435	Auxiliary Boiler (99.9 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 0.0750 lb/MMbtu hourly 7.49 lb/hr

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO Emission Limits
Harrison Power	P0122266 (04/19/2018)	OH-0377	Auxiliary Boiler B001 (44.55 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 0.0375 lb/MMbtu, 1.67 lb/hr, 0.90 tons/year
			Auxiliary Boiler B002 (80 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 0.0310 lb/MMbtu, 2.48 lb/hr, 1.34 tons/year *Note: this permit expired 11/6/2021*
Harrison County Power Plant	R14-0036 (03/27/2018)	WV-0029	Auxiliary Boiler (77.80 MMBtu/hr) (Annual Emissions based on 4,600 hrs/yr)	**Control Method:** Good combustion practices **CO Emission Limit:** 2.88 lb/hr, 6.58 tons/year 0.0370 lb/MMbtu
Renovo Energy Center LLC / Renovo PLT	18-00033A (01/26/2018)	PA-0316	Auxiliary Boiler (13.56 MMBtu/hr)	**Control Method:** None **CO Emission Limit:** 0.036 lb/MMbtu 2.14 tons/year
Dania Beach Energy Center	0110037-017-AC (12/04/2017)	FL-0363	Auxiliary Boiler (99.80 MMBtu/hr)	**Control Method:** Clean fuel **CO Emission Limit:** 0.080 lb/MMbtu
Long Ridge Energy Generation LLC - Hannibal Power	P0122829 (11/07/2017)	OH-0375	Auxiliary Boiler (26.8 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 0.99 lb/hr, 2.48 tons/year 0.0370 lb/MMbtu
Oregon Energy Center	P0121049 (09/27/2017)	OH-0372	Auxiliary Boiler (37.8 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 2.08 lb/hr, 2.08 tons/year 0.0550 lb/MMbtu
Trumbull Energy Center	P0122331 (09/07/2017)	OH-0370	Auxiliary Boiler (37.8 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 2.08 lb/hr, 2.08 tons/year 0.0550 lb/MMbtu
Holland Board of Public Works - East 5th Street	107-13C (12/05/2016)	MI-0424	Auxiliary Boiler (83.5 MMBtu/hr)	**Control Method:** Good combustion practices **CO Emission Limit:** 0.0770 lb/MMBtu
South Field Energy LLC	P0119495 (09/23/2016)	OH-0367	Auxiliary Boiler (99.0 MMBtu/hr)	**Control Method:** Good combustion practices, NG/ultra-low sulfur diesel **CO Emission Limit:** 7.92 lb/hr, 15.39 tons/year 0.0550 lb/MMBtu (NG) 0.08 lb/MMBtu (diesel)
CPV Fairview Energy Center	11-00536A (09/02/2016)	PA-0310	Auxiliary Boiler (92.40 MMBtu/hr)	**Control Method:** ULSD and good combustion practices **CO Emission Limit:** 0.037 lb/MMBtu

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO Emission Limits
				6.84 tons/year

Levels of control for CO range from 0.031 to 0.08 lb/MMBtu with good combustion practices and no add-on controls. The most common CO emission limit for similar auxiliary boilers is 0.037 lb/MMBtu. Although oxidation catalyst is technically feasible, this technology is not implemented for the sources in RBLC data for small boilers such the one proposed by Maple Creek Energy I LLC. 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. Since it can take time for the exhaust stream to reach the required operating temperature range for efficient oxidation, the control efficiency of thermal or oxidation catalysts for a small boiler is lower when compared to a unit that runs at steady-state. The auxiliary boiler at Maple Creek Energy I LLC will be used to aid in startup operation of the CCCT generating unit. Therefore, this control technology is not considered for the proposed boiler.

The only remaining technology is good design and operating practices. A properly designed and operated boiler minimizes CO formation by ensuring that the boiler temperature and oxygen availability are adequate for complete combustion. Good design and operating practices is considered BACT for CO emissions for the proposed boiler.

Step 5: Select BACT (CO)

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler (AUX) shall be as follows:

(1) CO emissions from the natural gas-fired auxiliary boiler (AUX) shall not exceed 0.037 lb/MMBtu.

(2) CO emissions from the natural gas-fired auxiliary boiler (AUX) shall be controlled through the use of good combustion practices.

H_2SO_4 BACT Determination: Auxiliary Boiler

Step 1: Identify Potential Control Technologies (H_2SO_4)

Emissions of Sulfuric Acid (H_2SO_4) emissions depend upon the sulfur content of the fuel and oxidation of SO_2 to SO_3, followed by immediate conversion of SO_3 to H_2SO_4 when water vapor is present. Sulfuric Acid (H_2SO_4) emissions are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

(1) Flue Gas Desulfurization (FGD) System);
(2) Dry Sorbent Injection; and
(3) Fuel Specification.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

Flue Gas Desulfurization (FGD) System
A flue gas desulfurization system (FGD) is comprised of a spray dryer that uses lime as a reagent followed by particulate control or wet scrubber that uses limestone as a reagent. FGD is an established technology. FGD typically operates at a temperature of approximately 300°F to 700°F (wet) and 300°F to 1830°F (dry). The FGD has a waste stream inlet pollutant concentration of 2,000ppmv. Absorption of SO_2 is accomplished by the contact between the exhaust and an alkaline reagent, which results in the formation of neutral salts. Wet systems employ reagents using packed or spray towers and generate wastewater streams, while dry systems inject slurry reagent into the exhaust stream to react, dry and be removed downstream by particulate control equipment. By removing SO_2 from the exhaust stream, conversion of SO_2 to SO_3 and H_2SO_4 is reduced. Chlorine emissions can result in salt deposition within the absorber and in downstream equipment. Wet systems may require flue gas re-heating downstream of the absorber to prevent corrosive condensation. Inlet streams for dry systems must be cooled as appropriate, and dry systems require use of particulate controls to collect the solid neutral salts.

FGD systems are not listed in the RBLC as BACT for the control of H_2SO_4 emissions for auxiliary boilers. Technology has not been applied to natural gas auxiliary boilers due to very low H_2SO_4 emissions. Controls would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of flue gas desulfurization system (FGD) is not a technically feasible option for the Auxiliary Boiler at this source.

Dry Sorbent Injection
A post-combustion technology in which a calcium or sodium-based sorbent reacts with SO_2 and SO_3 and is removed downstream by particulate control equipment. The reduced availability of SO_2 and SO_3 in the exhaust stream reduces H_2SO_4 formation, thereby reducing H_2SO_4 emissions. The system requires use of particulate controls to collect the reaction solids. Dry sorbent injection is not listed in the RBLC as BACT for the control of H_2SO_4 emissions for auxiliary boilers. Technology has not been applied to natural gas auxiliary boilers due to very low SO_2 and H_2SO_4 emissions. Controls would not provide any measurable emission reduction.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of dry sorbent injection is not a technically feasible option for the Auxiliary Boiler at this source.

Fuel Specifications
Combusting only clean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating H_2SO_4 emissions. Fuel Specifications are included in RBLC for the control of H_2SO_4 emissions from Auxiliary Boilers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Fuel Specifications is a technically feasible option for the Auxiliary Boiler at this source.

<u>Step 3: Rank the Remaining Control Technologies by Control Effectiveness</u>

The following measures have been identified for control of H_2SO_4 resulting from the operation of the Auxiliary Boiler.

(1) Fuel Specifications

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) under Process Type Code 13.310 (Commercial/Institutional-Size Boilers/Furnaces <100 MMBtu/hr - Natural Gas), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Summary of RBLC Database Review - Auxiliary Boilers - Natural Gas

Facility	Permit Number & Date	RBLC ID #	Emission Unit	H_2SO_4 Emission Limits
Maple Creek Energy I LLC	Proposed	--	Natural Gas-Fired Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Use of pipeline-quality natural gas **H_2SO_4 Emission Limit:** 0.00014 lb/MMBtu, 3-hr avg.
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Natural Gas Auxiliary Boiler (100 MMBtu/hr)	**Control Method:** Use of low sulfur fuel & combustion controls, pipeline quality natural gas **H_2S Emission Limit:** 0.01 lb/MMBtu
Maple Creek Energy LLC	T153-45909-00056 (06/19/2023)	IN-0365	Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Use of only pipeline quality natural gas **H_2SO_4 Emission Limit:** 0.00014 lb/MMBtu
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	Auxiliary Boiler (80 MMBtu/hr)	**Control Method:** Use of only natural gas with a sulfur content of no greater than 0.5 grains (gr) per 100 scf **H_2SO_4 Emission Limit:** 0.020 lb/MMBtu
Shady Hills Combined Cycle Facility	1010524-003-AC (PSD-FL-444A) (06/07/2021)	FL-0371	Auxiliary Boiler (60 MMBtu/hr)	**Control Method:** Limited sulfur content in fuel **H_2SO_4 Emission Limit:** 1.4 grains/100 scf *(converts to 0.002 lb/MMBtu)* 20% opacity
Jackson Generation, LLC	17040013 (12/31/2018)	IL-0130	Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Good combustion practices **H_2SO_4 Emission Limit:** 0.10 lb/hr *(converts to 0.001 lb/MMBtu)*
ESC Brooke County Power I, LLC Brooke County Power Plant	R14-0035 (09/18/2018)	WV-0032	Auxiliary Boiler (111.9 MMBtu/hr)	**Control Method:** NA **H_2SO_4 Emission Limit:** 0.02 lb/hr, 0.03 tons/year, 0.0001 lb/MMBtu
CPV Three Rivers, LLC	16060032 (07/30/2018)	IL-0129	Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Good combustion practices **H_2SO_4 Emission Limit:** 0.10 lb/hr *(converts to 0.001 lb/MMBtu)* 0.20 tons/year
Belle River Combined Cycle Power Plant	19-18 (07/16/2018)	MI-0435	Auxiliary Boiler (99.9 MMBtu/hr)	**Control Method:** Good combustion practices, low sulfur fuel **H_2SO_4 Emission Limit:** 0.34 gr s/100 scf *(converts to 0.0005 lb/MMBtu)*
Harrison Power	P0122266 (04/19/2018)	OH-0377	Auxiliary Boiler B001 (44.55 MMBtu/hr)	**Control Method:** Pipeline quality NG **H_2SO_4 Emission Limit:** 0.004 lb/hr, 0.002 tons/year, $8.0x10^{-5}$ lb/MMBtu

Facility	Permit Number & Date	RBLC ID #	Emission Unit	H_2SO_4 Emission Limits
			Auxiliary Boiler B002 (80 MMBtu/hr)	**Control Method:** Pipeline quality NG **H_2SO_4 Emission Limit:** 0.0180 lb/hr, 0.010 tons/year, 2.2×10^{-4} lb/MMBtu
Harrison County Power Plant	R14-0036 (03/27/2018)	WV-0029	Auxiliary Boiler (77.80 MMBtu/hr) (Annual Emissions based on 4,600 hrs/yr)	**Control Method:** Use of natural gas **H_2SO_4 Emission Limit:** 0.0132 lb/hr, 0.030 tons/year, 0.0002 lb/MMBtu
Dania Beach Energy Center	0110037-017-AC (12/04/2017)	FL-0363	Auxiliary Boiler (99.80 MMBtu/hr)	May only fire natural gas with sulfur content less than 2 grains per 100 scf. This limits SO2, SAM, PM, PM10, and PM2.5.
Long Ridge Energy Generation LLC - Hannibal Power	P0122829 (11/07/2017)	OH-0375	Auxiliary Boiler (26.8 MMBtu/hr)	**Control Method:** Low sulfur fuel **H_2SO_4 Emission Limit:** 0.0030 lb/hr, 0.0070 tons/year, 1.10×10^{-4} lb/MMBtu
Oregon Energy Center	P0121049 (09/27/2017)	OH-0372	Auxiliary Boiler (37.8 MMBtu/hr)	**Control Method:** Low sulfur fuel **H_2SO_4 Emission Limit:** 0.0040 lb/hr, 0.0040 tons/year, 1.15×10^{-4} lb/MMBtu
Trumbull Energy Center	P0122331 (09/07/2017)	OH-0370	Auxiliary Boiler (37.8 MMBtu/hr)	**Control Method:** Low sulfur fuel **H_2SO_4 Emission Limit:** 0.0087 lb/hr, 0.0087 tons/year, 2.3×10^{-4} lb/MMBtu
South Field Energy LLC	P0119495 (09/23/2016)	OH-0367	Auxiliary Boiler (99.0 MMBtu/hr)	**Control Method:** NG/ultra-low sulfur diesel **H_2SO_4 Emission Limit:** 0.0110 lb/hr, 0.030 tpy, 1.1×10^{-4} lb/MMBtu (NG) 1.1×10^{-4} lb/MMBtu (Diesel)
CPV Fairview Energy Center	11-00536A (09/02/2016)	PA-0310	Auxiliary Boiler (92.40 MMBtu/hr)	**Control Method:** ULSD and good combustion practices **H_2SO_4 Emission Limit:** 20.00 tons/year, 0.0011 lb/MMBtu

For H_2SO_4, the levels of control range from the most stringent level of control identified as 0.00011 to 0.02 lb/MMBtu. A project's H_2SO_4 emissions can vary greatly depending on assumptions related to conversion of SO2 to H_2SO_4 which is indicated by the wide range of emission limits. The proposed BACT limit for H_2SO_4 for the auxiliary boiler of 0.00014 lb/MMBtu is at the lower edge of the range of recently approved projects. This rate is based on allowance for 10 percent conversion of SO2 to H_2SO_4.

<u>Step 5: Select BACT</u>

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler (AUX) shall be as follows:

(1) H_2SO_4 emissions from the natural gas-fired auxiliary boiler (AUX) shall not exceed 0.00014 lb/MMBtu.

(2) H_2SO_4 emissions from the natural gas-fired auxiliary boiler (AUX) shall be controlled through the use of only pipeline quality natural gas.

GHG BACT Determination: Auxiliary Boiler

Step 1: Identify Potential Control Technologies

CO_2 is by far the dominant greenhouse gas (GHG) from this source. CH_4 and N_2O are present only in very small amounts, are incidental to combustion, and trend with the CO_2 emissions. There are no known supplemental controls for N_2O or methane emissions from gas-fired units. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

(1) Carbon Capture and Sequestration (CCS)
(2) Operating and Maintenance (O&M) Practices;
(3) Efficient Burner Design;
(4) Improved Combustion Measures: Combustion Tuning;
(5) Improved Combustion Measures: Optimization & Digital Control System;
(6) Air Preheat & Economizers;
(7) Turbulators for Firetube Boilers;
(8) Boiler Insulation;
(9) Minimization of Air Infiltration;
(10) Boiler Blowdown Heat Exchange;
(11) Condensation Return System;
(12) Minimization of Gas-side heat Transfer Surface Deposits;
(13) Steam Line Maintenance;
(14) Alternative Fuels-Biomass/Co-firing; and
(15) Fuel Switching.
(16) Good Combustion Practices

Step 2: Eliminate Technically Infeasible Options

(a) Carbon Capture and Sequestration (CCS)

CCS is not feasible solely for small combustion units such as the 96 MMBtu/hr natural gas-fired auxiliary boiler 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 CCCT generating units. Therefore, this option is not evaluated in the subsequent analysis. In addition, the RBLC data does not include CCS as control option for any of the listed auxiliary boiler sources.

(b) Operating and Maintenance (O&M) 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.

Rehabilitation may focus on life extension and reliability improvement of the plant or may include additional measures that improve plant efficiency, occasionally above the original design efficiency. The efficiency can be improved by retrofitting combustion control technologies such as heat recovery systems, control technology, and upgraded burners.

Additional GHG reductions can be achieved through energy improvements in the steam/hot water distribution system, the boiler auxiliaries, or in process efficiency improvements.

Operation and maintenance according to the manufacturer's emission-related instructions or per a facility-developed maintenance plan (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.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Operating and Maintenance (O&M) practices is a technically feasible option for the Auxiliary Boilers at this source.

(c) Efficient Burner Design

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-NO_X 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 burner designs will be employed, taking into account the size, fuel flexibility, operating loads, and other site-specific conditions and objectives for each piece of combustion equipment.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of efficient burner designs is a technically feasible option for the Auxiliary Boilers at this source.

(d) 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 NO_X 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 the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Improved Combustion Measures: Combustion Tuning is a technically feasible option for the Auxiliary Boilers at this source.

(e) 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 package boilers will be equipped with oxygen trim controls and oxygen analyzers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Operating and Maintenance (O&M) practices is a technically feasible option for the Auxiliary Boilers at this source.

(f) 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 boilers will be equipped with an economizer.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Improved Combustion Measures: Optimization & Digital Control System is a technically feasible option for the Auxiliary Boilers at this source.

(g) 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 boilers will already come equipped with an economizer, the turbulator was not considered to be necessary.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of turbulators for fireture boiler is a technically feasible option for the Auxiliary Boilers at this source.

(h) Boiler Insulation

Significant heat losses can occur through the boiler shell. Proper insulation is used to minimize such losses. The refractory material lining inside the boiler is the primary insulating material, but properly applied insulation on the outer boiler surface can also reduce heat losses.

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 the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of boiler insulation is a technically feasible option for the Auxiliary Boilers at this source.

(i) 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 the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of minimization of air infiltration is a technically feasible option for the Auxiliary Boilers at this source.

(j) 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.

High blowdown rates and boiler pressures are ideal conditions for blowdown recovery. Any boiler with continuous blowdown exceeding 5% of the steam rate exhibits significant potential for blowdown waste heat recovery. Manufacturers specified that a 1% thermal efficiency can be achieved by this method. In certain cases, significant energy savings can be accomplished by recovering heat from boiler blowdown.

Site-specific conditions and economic considerations must be addressed to determine whether this measure involving heat recovery is technically and economically viable; it is necessary to consider its viability on a case-by-case basis.

Expected efficiency improvements vary based on boiler blowdown rate and boiler pressure. The proposed natural gas boilers are stand-by, auxiliary units that are not intended to operate a significant number of hours. As such, a blowdown heat exchanger is not economically feasible.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of boiler blowdown heat exchange is a technically feasible option for the Auxiliary Boilers at this source.

(k) 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 % recovery. The selected package boilers will be equipped with a condensate return system.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of condensation return system is a technically feasible option for the Auxiliary Boilers at this source.

(l) 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.

Advanced soot blowing systems can be calibrated to activate automatically in response to feedback signals (e.g., exit gas temperature, heat transfer sensors) to optimize operations and effectiveness.

The relationship between deposits and heat transfer deterioration varies with the type of fuel and ash characteristics. For example, ash deposits of similar thickness will have different impacts on heat transfer based on the refractory characteristics of the individual ashes. The extent to which dirty heat transfer surfaces affect efficiency can be estimated from an increase in stack temperature relative to a “clean operation” or baseline condition. Efficiency is reduced by approximately 1% for every 40 °F increase in stack temperature. Changes in exit gas temperatures of over 120 °F due to boiler slagging and fouling would correspond to about a 3% decrease in efficiency. Excessive slagging may also affect the outlet steam conditions of the boiler (i.e., reducing steam temperatures or necessitating the installation of attemperation sprays).

Efficiency gains of 1 - 3% may be gained within industrial, commercial, and institutional boilers by minimizing boiler surface deposition.
Natural gas-fired boilers do not typically employ soot blowing systems given the reduced ash content of gaseous fuels.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of minimization of gas-side heat transfer surface deposits is a technically feasible option for the Auxiliary Boilers at this source.

(m) 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 the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of streamline maintenance is a technically feasible option for the Auxiliary Boilers at this source.

(n) 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.
Technically infeasible for solid and liquid biomass fuels - boiler design will not be capable of co-firing solid or liquid. Feasible for gaseous biomass fuels. Co-firing of gaseous biomass fuels will result in only a minor decrease in GHG emissions.

Availability of gaseous biomass-based fuels is limited such that a consistent supply of fuel cannot be assured over the life of the boilers. In addition, the combustion of biomass-based fuels can affect compliance with BACT limits for other pollutants, such as NO_X and CO. Therefore, the boilers will be initially constructed and operated to utilize only natural gas. Should a consistent, reliable source of gaseous biomass-based fuel become available, use of these fuels will be evaluated on an individual basis.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of alternative fuels-biomass/co-firing is not a technically feasible option for the Auxiliary Boilers at this source.

(o) 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. Technically infeasible - does not apply to the natural gas combustion units.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of fuel switching is not a technically feasible option for the Auxiliary Boilers at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the technical feasibility analysis in Step 2, the remaining control technologies may be ranked as follows for controlling GHG emissions from the Auxiliary Boilers.

(1) Boiler Insulation; (7% CO_2 Reduction)
(2) Efficient Burner Design (6% CO_2 Reduction)
(3) Air Preheat & Economizers; (5% CO_2 Reduction)
(4) Improved Combustion Measures: Optimization & Digital Control System; (0.5-5% CO_2 Reduction)
(5) Minimization of Air Infiltration; (4% CO_2 Reduction)
(6) Improved Combustion Measures: Combustion Tuning; (3% CO_2 Reduction)
(7) Minimization of Gas-side heat Transfer Surface Deposits;(1-3% CO_2 Reduction)
(8) Turbulators for Firetube Boilers; (1% CO_2 Reduction)
(9) Steam Line Maintenance;
(10) Operating and Maintenance (O&M) Practices;
(11) Condensation Return System;

Step 4: Evaluate the Most Effective Controls and Document the Results (GHG)

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) under Process Type Code 13.310 (Commercial/Institutional-Size Boilers/Furnaces <100 MMBtu/hr - Natural Gas), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date.

Summary of RBLC Database Review - Auxiliary Boilers - Natural Gas

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Emission Limits
Maple Creek Energy I LLC	Proposed	--	Natural Gas-Fired Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 11,244 tons per twelve (12) consecutive month period *(proposed limit was determined using 40 CFR 98 Table C-2)*
Duke Energy, Indiana, Inc. - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	Auxiliary Boiler (225 MMBtu/hr)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 115,400 tons per twelve (12) consecutive month period *(no lb/MW-hr listed)*
Wabash Valley Resources, LLC	167-45208-00091 (01/11/2024)	IN-0371	Auxiliary Boiler (20 MMbtu/hr)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 117 lb/MMbtu (34.3 lb/MW-hr)
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Natural Gas Auxiliary Boiler (100 MMBtu/hr)	**Control Method:** Ultra-low NOx burners, flue gas recirculation, pipeline quality natural gas **CO_{2e} Emission Limit:** 160 lb/MMbtu
Maple Creek Energy LLC	T153-45909-00056 (06/19/2023)	IN-0365	Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 11,244 tons/year *(no lb/MW-hr listed)*
LBWL - Erickson Station	74-18D (12/20/2022)	MI-0454	NG-Fired Auxiliary Boiler (50 MMbtu/hr)	**Control Method:** Low carbon fuel (pipeline quality natural gas), good combustion practices, and energy efficient measures **CO_{2e} Emission Limit:** 25,644 tons/year *(no lb/MW-hr listed)*

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Emission Limits
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	Auxiliary Boiler (80 MMBtu/hr)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 5,059 tons/year *(no lb/MW-hr listed)*
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Auxiliary Boiler (61.50 MMBtu/hr)	**Control Method:** Low carbon fuel (pipeline quality natural gas), and energy efficient measures **CO_{2e} Emission Limit:** 31,540 tons/year *(no lb/MW-hr listed)*
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/23/2022)	MI-0542	Auxiliary Boiler (61.50 MMBtu/hr)	**Control Method:** Low carbon fuel (pipeline quality natural gas), and energy efficient measures **CO_{2e} Emission Limit:** 31,540 tons/year
Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Auxiliary Boiler (80 MMBtu/hr)	**Control Method:** Good combustion practices, compliance with 40 CFR 63 Subpart DDDDD **CO_{2e} Emission Limit:** 117 lb/MMBtu (34.3 lb/MW-hr)
WPL - Riverside Energy Center	20-POY-178 (01/22/2021)	WI-0305	Natural Gas Auxiliary Boiler (83.5 MMBtu/hr)	**Control Method:** Combust only pipeline quality natural gas **CO_{2e} Emission Limit:** 157 lb CO_2 / MMBtu heat (steam) input (equal to 46.01 lb/MW-hr) Shall maintain a minimum 75% conversion of heat input to steam energy (conversion rate) in any month averaged over any 12 consecutive month period. Any hour of boiler operation in which warming mode was the only mode of operation shall not be included in the calculation of the conversion efficiency. Warming mode is defined as operation of the boiler at less than 4 MMBtu/hr heat input.
Alabama Power Company -Plant Barry	503-1001 (11/09/2020)	AL-0328	Auxiliary Boiler (90.50 MMBtu/hr)	**Control Method:** None **CO_{2e} Emission Limit:** 46,416 tons/year
Indeck Niles, LLC	75-16B (11/26/2019)	MI-0445	Auxiliary Boiler (182 MMBtu/hr)	**Control Method:** Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas) **CO_{2e} Emission Limit:** 93,346 tons/year
Thomas Township Energy, LLC	210-18 (08/21/2019)	MI-0442	Auxiliary Boiler (80 MMBtu/hr)	**Control Method:** Energy efficiency **CO_{2e} Emission Limit:** 41,031 tons/year *(no lb/MW-hr listed)*
Jackson Generation, LLC	17040013 (12/31/2018)	IL-0130	Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 11,250 tons/year *(no lb/MW-hr listed)*
ESC Brooke County Power I, LLC Brooke County Power Plant	R14-0035 (09/18/2018)	WV-0032	Auxiliary Boiler (111.9 MMBtu/hr)	**Control Method:** Use of natural gas **CO_2 Emission Limit:** 14,768 lb/hr 33,790 tons/year *(no lb/MW-hr listed)*
CPV Three Rivers, LLC	16060032 (07/30/2018)	IL-0129	Auxiliary Boiler (96 MMBtu/hr)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 22,500 tons/year *(no lb/MW-hr listed)*
Belle River Combined Cycle Power Plant	19-18 (07/16/2018)	MI-0435	Auxiliary Boiler (99.9 MMBtu/hr)	**Control Method:** Energy efficiency measures, use of natural gas

Facility	Permit Number & Date	RBLC ID #	Emission Unit	GHG Emission Limits
				CO_{2e} Emission Limit: 25,623 tons/year *(no lb/MW-hr listed)*
Harrison Power	P0122266 (04/19/2018)	OH-0377	Auxiliary Boiler B001 (44.55 MMBtu/hr)	**Control Method:** Good combustion practices and pipeline quality natural gas **CO_{2e} Emission Limit:** 2,817.6 tons/year *(no lb/MW-hr listed)*
			Auxiliary Boiler B002 (80 MMBtu/hr)	**Control Method:** Good combustion practices and pipeline quality natural gas **CO_{2e} Emission Limit:** 5,009.1 tons/year *(no lb/MW-hr listed)*
Harrison County Power Plant	R14-0036 (03/27/2018)	WV-0029	Auxiliary Boiler (77.80 MMBtu/hr)	**Control Method:** NA **CO_{2e} Emission Limit:** 9,107 lb/hr *(no lb/MW-hr listed)* 20,837 tons/year Annual Emissions based on 4,600 hrs/yr
Long Ridge Energy Generation LLC - Hannibal Power	P0122829 (11/07/2017)	OH-0375	Auxiliary Boiler (26.8 MMBtu/hr)	**Control Method:** Only natural gas combustion **CO_{2e} Emission Limit:** 7,845 tons/year *(no lb/MW-hr listed)*
Oregon Energy Center	P0121049 (09/27/2017)	OH-0372	Auxiliary Boiler (37.8 MMBtu/hr)	**Control Method:** Good combustion practices and natural gas combustion **CO_{2e} Emission Limit:** 4,502 tons/year *(no lb/MW-hr listed)*
Trumbull Energy Center	P0122331 (09/07/2017)	OH-0370	Auxiliary Boiler (37.8 MMBtu/hr)	**Control Method:** Good combustion practices and natural gas combustion **CO_{2e} Emission Limit:** 4,456 tons/year *(no lb/MW-hr listed)*
Holland Board of Public Works - East 5th Street	107-13C 12/05/2016	MI-0424	Auxiliary Boiler (83.5 MMBtu/hr)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 43,283 tons/year *(no lb/MW-hr listed)*
South Field Energy LLC	P0119495 09/23/2016	OH-0367	Auxiliary Boiler (99.0 MMBtu/hr)	**Control Method:** GCP, NG, and Ultra-low sulfur diesel **CO_{2e} Emission Limit:** 32,171 tons/year 120 lb/MMBtu (35.2 lb/MW-hr) for natural gas 160 lb/MMBtu (46.9 lb/MW-hr) for diesel

For GHGs, BACT is predominantly based on the use of clean-burning fuels, such as natural gas. Most auxiliary boilers have only an annual tons per year limit specified, based on annual gas use. The proposed BACT limit for GHGs for the Facility's auxiliary boiler is 11,244 tons per year of CO_{2e} based upon firing natural gas as the sole fuel, which is the lowest GHG-emitting fossil fuel.

Step 5: Select BACT (GHG)

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler (AUX) shall be as follows:

(1) CO_{2e} emissions from the natural gas-fired auxiliary boiler (AUX) shall not exceed 11,244 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(2) CO_{2e} emissions from the natural gas-fired auxiliary boiler (AUX) shall be controlled through the use of good combustion practices.

Summary of Emergency Diesel Generator Engine

$PM/PM_{10}/PM_{2.5}$ BACT Determination: Diesel-Fired Emergency Generator

Step 1: Identify Potential Control Technologies ($PM/PM_{10}/PM_{2.5}$)

Particulate emissions from internal combustion engines primarily result from incomplete combustion. Ash and metallic additives in the fuel may also contribute to the particulate content of the exhaust. Particulate may be generated when the temperature is not high enough to ignite the fuel, when lubricating oil leaks and is partially burned, and when combustion is oxygen deficient. Higher sulfur content fuels tend to increase particulate emissions due to the formation of sulfates during the oxidation of SO2, which are fine particulates.

Decreases in particulate emissions are generally seen through proper engine maintenance and good combustion practices. Add-on controls for particulate emissions from internal combustion engines include oxidation catalysts and diesel particulate filters. These are discussed below:

Diesel Oxidation Catalysts
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. The level of particulate control is a function of the soluble organic fraction of particulate. The soluble organic fraction can be reduced by as much as 90%. Total particulate emissions may be reduced by up to 40-50%, although 20-35% is typical.

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. Collection efficiencies of filters range from 50-90%. Catalytic coatings on diesel particulate filters can also reduce CO and VOC emissions.

Good Combustion Practices
Organic particulate matter emissions are caused through incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form in the fuel injection plume that cause unburned fuel to pyrolyze at the high engine temperature and form soot. Soot formation can be minimized by improving the fuel air mixing through enhanced fuel injection systems, air management systems, combustion system designs, and pre-mixed diesel combustion.

Fuel Choice and Usage Limitations
Most of the sulfur present in fuel is oxidized to SO2. Through further reactions, sulfates, which are fine particles, can also form. Therefore, higher sulfur fuels can lead to higher particulate emissions. By limiting the sulfur content in fuel, both SO2 and particulate emissions can be reduced. Additionally, restrictions on the amount of fuel or hours of operation can further limit all emissions.

Step 2: Eliminate Technically Infeasible Options ($PM/PM_{10}/PM_{2.5}$)

While add-on controls are not typically used for emergency engines, no controls are being eliminated based on technical infeasibility.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness ($PM/PM_{10}/PM_{2.5}$)

Control/Method	***% Reduction***
Diesel Particulate Filters	50-90%
Diesel Oxidation Catalyst	20-50%
Good Combustion Practices	Varies
Sulfur Content of Fuel / Fuel Use Limitations	Varies

Step 4: Evaluate the Most Effective Controls and Document the Results ($PM/PM_{10}/PM_{2.5}$)

The following table summarizes other BACT determinations for emergency diesel-fired internal combustion engines and generators that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) under Process Type Code 17.110 (Large Internal Combustion Engines >500 HP - Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel)), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date. Fire pump engines were excluded from this as not comparable as supported by the EPA developing different limits for fire pumps in 40 CFR 60, Subpart IIII.

Summary of RBLC Database Review - Large Internal Combustion Engines - Diesel Fuel

Facility	Permit Number & Date	RBLC ID #	Emission Unit	$PM/PM_{10}/PM_{2.5}$ Emission Limits
Maple Creek Energy I LLC	Proposed	--	Diesel-fired Emergency Generator (2,012 HP)	**Control Method:** State-of-the-art combustion design and good combustion practices **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.15 g/hp-hr *(converts to 0.20 g/kW-hr and 0.67 lb/hr)*
Maple Creek Energy I LLC	T153-45909-00056 (06/19/2023)	IN-0365	Emergency Diesel Generator (2,012 HP)	**Control Method:** None **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.15 g/hp-hr *(converts to 0.20 g/kW-hr and 0.67 lb/hr)*
Maple Creek Energy II LLC	Proposed	--	Diesel-fired Emergency Generator (2,012 HP)	**Control Method:** State-of-the-art combustion design and good combustion practices **PM Emission Limit:** 0.05 g/hp-hr *(converts to 0.07 g/kW-hr)* 0.22 lb/hr **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.07 g/hp-hr *(converts to 0.10 g/kW-hr)* 0.33 lb/hr
Hybar	2470-AOP-R2 (10/02/2025)	AR-0191	Emergency Generators (2,700 kW, each)	**Control Method:** Good operating practices and limited hours of operation **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.10 g/bhp-hr *(converts to 0.14 g/kW-hr and 0.60 lb/hr)*
Marquis Carbon Capture LLC	23110009 (06/23/2025)	IL-0137	Diesel Emergency Engine (600 kW / 804.6 HP)	**Control Method:** Use of ultra-low sulfur diesel (ULSD) as fuel, good combustion practices, 500 hours/year operation **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.20 g/KW-hr *(converts to 0.15 g/hp-hr)* 0.27 lb/hr
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	Four (4) Diesel Black Start Emergency Generators (3,000 kW / 4,023 HP,	**Control Method:** Good combustion practices and low sulfur fuel **PM Emission Limit:** 0.15 g/hp-hr *(converts to 0.20 g/kW-hr)*

Facility	Permit Number & Date	RBLC ID #	Emission Unit	$PM/PM_{10}/PM_{2.5}$ Emission Limits
			each)	1.43 lb/hr **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.17 g/hp-hr *(converts to 0.23 g/kW-hr)* 1.65 lb/hr
			ULSD Emergency Generator (1,500 kW / 2,011.5 HP)	**Control Method:** Good combustion practices and low sulfur fuel **PM Emission Limit:** 0.05 g/hp-hr *(converts to 0.07 g/kW-hr)* 0.22 lb/hr **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.07 g/hp-hr *(converts to 0.10 g/kW-hr)* 0.33 lb/hr
Duke Energy, Indiana, Inc. - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	Emergency Generators (2,000 HP)	**Control Method:** Good combustion practices **PM Emission Limit:** 0.15 g/hp-hr *(converts to 0.20 g/kW-hr and 0.66 lb/hr)*
Shintech Plaquemine Plant 4	PSD-LA-857 (12/16/2024)	LA-0403	Five (5) Diesel Emergency Generators (2,346 HP, each)	**Control Method:** None **PM_{10} Emission Limit:** 0.77 lb/hr 0.20 g/kW-hr *(converts to 0.15 g/hp-hr)* **$PM_{2.5}$ Emission Limit:** 0.76 lb/hr 0.20 g/kW-hr *(converts to 0.15 g/hp-hr)*
			One (1) Diesel Emergency Generator (2,012 HP)	**Control Method:** None **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.66 lb/hr 0.02 tons/year 0.20 g/kW-hr *(converts to 0.15 g/hp-hr)*
XCEL Energy Blue Lake	13900010-105 (08/07/2024)	MN-0095	Three (3) ULSD Emergency Generators (1,049 HP, each)	**Control Method:** Emergency classification, hourly restriction, ULSD, and NSPS compliance **PM Emission Limit:** 0.15 g/hp-hr *(converts to 0.20 g/kW-hr)* 0.35 lb/hr **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.16 g/hp-hr *(converts to 0.22 g/kW-hr)* 0.39 lb/hr
Mitsubishi Chemical America, Inc. MCA Geimar Site	PSD-LA-850 (07/24/2024)	LA-0406	Diesel Emergency Generator (1,140 HP)	**Control Method:** Proper equipment design and good combustion practices, use ultra-low sulfur diesel as fuel **$PM_{10}/PM_{2.5}$ Emission Limit:** 1.50 g/hp-hr *(converts to 2.04 g/kW-hr and 3.77 lb/hr)*
Koch Methanol (KME) Facility	PSD-LA-851 (12/20/2023)	LA-0401	Two (2) Diesel Emergency Generators (2,923 HP)	**Control Method:** None **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.84 lb/hr *(converts to 0.13 g/hp-hr and 0.18 g/kW-hr)*
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Diesel Emergency Generator (1,490 HP)	**Control Method:** Good combustion practices and clean fuels. The sulfur content of the diesel fuel oil fired may not exceed 15 ppm. **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.15 g/hp-hr *(converts to 0.20 g/kW-hr and 0.49 lb/hr)* 500 hours/year (rolling)
Nucor Steel	107-45480-00038 (03/30/2023)	IN-0359	Diesel Emergency Generator (3,000 HP)	**Control Method:** Certified engine **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.15 g/hp-hr

Facility	Permit Number & Date	RBLC ID #	Emission Unit	$PM/PM_{10}/PM_{2.5}$ Emission Limits
				(converts to 0.20 g/kW-hr and 0.99 lb/hr)
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	Two (2) Emergency Ultra-Low Sulfur Diesel Engines (1250 kW / 1676.3 HP, each)	**Control Method:** None **PM/PM10/PM2.5 Emission Limit:** 0.20 g/kW-hr *(converts to 0.15 g/hp-hr and 0.55 lb/hr)*
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Diesel Emergency Generator (1,341 HP)	**Control Method:** Diesel particulate filter, good combustion practices **PM Emission Limit:** 0.20 g/kW-hr *(converts to 0.15 g/hp-hr and 0.44 lb/hr)* **PM_{10} Emission Limit:** 0.54 lb/hr *(converts to 0.18 g/hp-hr and 0.25 g/kW-hr)* **$PM_{2.5}$ Emission Limit:** 0.52 lb/hr *(converts to 0.18 g/hp-hr and 0.24 g/kW-hr)*
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/03/2022)	MI-0452	Diesel Emergency Generator (1,341 HP)	**Control Method:** Diesel particulate filter, good combustion practices **PM Emission Limit:** 0.20 g/kW-hr *(converts to 0.15 g/hp-hr and 0.44 lb/hr)* **PM_{10} Emission Limit:** 0.54 lb/hr *(converts to 0.18 g/hp-hr and 0.25 g/kW-hr)* **$PM_{2.5}$ Emission Limit:** 0.52 lb/hr *(converts to 0.18 g/hp-hr and 0.24 g/kW-hr)*
Magnolia Power LLC- Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Diesel Emergency Generator (2,937 HP)	**Control Method:** Ultra-low sulfur diesel fuel and good combustion practices **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.15 g/hp-hr *(converts to 0.20 g/kW-hr and 0.97 lb/hr)*
Mountain State Clean Energy LLC Maidsville	R14-0038 (01/05/2022)	WV-0033	Emergency Generator (2,100 HP)	**Control Method:** Clean fuels and good combustion practices **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.23 lb/hr 0.20 g/kW-hr *(converts to 0.15 g/hp-hr)* *(Note: The RBLC incorrectly lists 0.15 g/kW-hr as the PM BACT emission limit. Section 5.1.1(a)(iii) of the WV Construction Permit R14-0038, issued on January 5, 2022, states, "PM/PM10 emissions from the engine shall not exceed 0.20 g/kW-hr.")*
Shady Hills Energy Center LLC	1010524-003-AC (PSD-FL-444A) (06/07/2021)	FL-0371	Diesel Emergency Generator (1500 kW / 2,011.5 HP)	**Control Method:** None **PM Emission Limit:** 0.20 g/kW-hr *(converts to 0.15 g/hp-hr and 0.67 lb/hr)*
Nucor Steel Gallatin, LLC	V-20-015 (04/19/2021)	KY-0115	Two (2) Emergency Generators (2,937 HP)	**Control Method:** Good Combustion and Operating Practices (GCOP) Plan **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.15 g/hp-hr *(converts to 0.20 g/kW-hr and 0.97 lb/hr)*

Facility	Permit Number & Date	RBLC ID #	Emission Unit	$PM/PM_{10}/PM_{2.5}$ Emission Limits
			One (1) Emergency Generator (2,922 HP)	**Control Method:** Good Combustion and Operating Practices (GCOP) Plan **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.15 g/hp-hr *(converts to 0.20 g/kW-hr and 0.97 lb/hr)*
Arauco North America	29-16E (12/18/2020)	MI-0448	Emergency Diesel Generator (1,500 kW / 2,011.5 HP) (500 hr/year)	**Control Method:** Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.66 lb/hr 0.20 g/kW-hr *(converts to 0.15 g/hp-hr and 0.67 lb/hr)*

A majority of the projects listed in the table above have emission limits that are compliant with 40 CFR 60, Subpart IIII for the emergency generator (0.15 g/hp-hr or 0.20 g/kW-hr for HP>750 engines).

Hybar (AR-0191) proposes a more stringent $PM/PM_{10}/PM_{2.5}$ emission limit, based on vendor emissions data, of 0.1 g/bhp-hr with good operating practices, limited hours of operation, and compliance with NSPS Subpart IIII. The emission factors used by the Hybar facility for the emergency diesel-fired generator are from Kohler KD2500 Tier 2 EPA Certified for Stationary Emergency Applications Emission Optimized Data Sheet, EPA D2 Cycle 5-mode weighted emission factors. Hybar has a large number of generators and HAP restrictions associated with the steel mill facility, resulting in a need for reduced emissions. 40 CFR 60, Subpart IIII establishes a $PM/PM_{10}/PM_{2.5}$ emission limit of 0.15 g/hp-hr for engines with a maximum power of greater than 750 HP.

Maple Creek Energy I LLC is proposing compliance with the 40 CFR 60 Subpart IIII limits.

Step 5: Select BACT ($PM/PM_{10}/PM_{2.5}$)

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the diesel-fired emergency generator (EG) shall be as follows:

(1) PM, PM_{10}, and $PM_{2.5}$ emissions from the diesel-fired emergency generator (EG) shall not exceed the values in the table below:

	PM	PM_{10}	$PM_{2.5}$
Emission Limit (g/hp-hr)	0.15	0.15	0.15
Emission Limit (lb/hr)	0.67	0.67	0.67

(2) PM, PM_{10}, and $PM_{2.5}$ emissions shall be controlled through the use of state-of-the-art combustion design and good combustion practices.

NOx BACT Determination: Diesel-Fired Emergency Generator

Step 1: Identify Potential Control Technologies (NOx)

During combustion processes, NOx emissions can form in three different ways: thermal NOx, fuel NOx, and prompt NOx. Thermal NOx occurs as a result of the reaction of nitrogen and oxygen in the combustion air, usually in the high temperature flame zone near the burners. Fuel NOx is a result of the reaction of any fuel-bound nitrogen compounds with oxygen during combustion. Prompt NOx occurs through early reactions of the nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NOx is usually small compared to thermal NOx emissions.

Decreases in NOx emissions are generally seen through proper engine maintenance and good combustion practices. Add-on controls for NOx emissions from internal combustion engines include selective catalytic reduction, nonselective catalytic reduction, and lean NOx catalysts. These are discussed below:

(a) Selective Catalytic Reduction (SCR)

The SCR process chemically reduces the NOx molecule into molecular nitrogen and water vapor. A nitrogen-based reagent such as ammonia is injected into the exhaust gas stream upstream of a catalyst. The reagent reacts selectively with the NOx within a specific temperature range in the presence of the catalyst and oxygen to reduce the NOx to nitrogen and water. SCR is capable of NOx reduction efficiencies in the range of 80-95%.

The NOx reduction reaction is only effective within a given temperature range, depending on the waste gas composition and type of catalyst. Optimum temperatures range from 600-750 °F for conventional catalyst types and 470-510 °F for platinum catalysts. SCR systems are capable of reducing NOx in low-concentration waste streams (as low as 20 ppm). Above 850 °F, ammonia begins to be oxidized to form additional NOx. The optimal effectiveness is also dependent on the ammonia-to-NOx ratio, space velocity, the ratio of flue gas flow rate to catalyst volume, and residence time.

(b) Nonselective Catalytic Reduction (NSCR)

Nonselective Catalytic Reduction also 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 CO2. CO is oxidized to CO2 and hydrocarbons are oxidized to CO2 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. NOx can be reduced by 80-95% under rich-burn conditions.

(c) 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. NOx reductions are in the range of 25-40%.

(d) Good Combustion Practices

Maximum reduction of thermal NOx generation can be achieved by control of both the combustion temperature and the air-to-fuel ratio. Due to the high flame temperatures and pressures of internal combustion engines, the majority of NOx formed is thermal NOx. With diesel fuel, little fuel NOx is formed.

Combustion Controls may include exhaust gas recirculation, injection timing retard, air-to-fuel ratio, and water injection.

Step 2: Eliminate Technically Infeasible Options (NOx)

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 water pump engine. No other control options are being eliminated due to technical infeasibility.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness (NOx)

Control/Method	***% Reduction***
Selective Catalytic Reduction	80-95%
Lean NOx Catalyst	25-40%
Good Combustion Practices	Varies

Step 4: Evaluate the Most Effective Controls and Document the Results (NOx)

The following table summarizes other BACT determinations for emergency diesel-fired internal combustion engines and generators that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) under Process Type Code 17.110 (Large Internal Combustion Engines >500 HP - Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel)), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date. Fire pump engines were excluded from this as not comparable as supported by the EPA developing different limits for fire pumps in 40 CFR 60, Subpart IIII.

Summary of RBLC Database Review - Large Internal Combustion Engines - Diesel Fuel

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Emission Limits
Maple Creek Energy I LLC	Proposed	--	Diesel-fired Emergency Generator (2,012 HP)	**Control Method:** State-of-the-art combustion design and good combustion practices **NOx + NMCH Emission Limit:** 4.8 g/hp-hr (6.5 g/kW-hr) 21.29 lb/hr
Maple Creek Energy I LLC	Existing T153-45909-00056 (06/19/2023)	IN-0365	Emergency Diesel Generator (2,012 HP)	**Control Method:** None **Emission Limit:** 4.8 g/hp-hr (6.5 g/kW-hr) for NMHC+NOx
Maple Creek Energy II LLC	Proposed	--	Diesel-fired Emergency Generator (2,012 HP)	**Control Method:** State-of-the-art combustion design and good combustion practices **NOx + NMCH Emission Limit:** 4.8 g/hp-hr (6.5 g/kW-hr) 21.29 lb/hr
Hybar	2470-AOP-R2 (10/02/2025)	AR-01-91	Emergency Generators (2,700 kW / 3,620 HP each)	**Control Method:** Good operating practices and limited hours of operation **NOx Emission Limit:** 3.9 g/hp-hr (5.3 g/kW-hr) *(Emission limit based on vendor data.)*
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	Four (4) Diesel Black Start Emergency Generators (3,000 kW / 4,023 HP, each)	**Control Method:** Good combustion practices and low sulfur fuels **NOx Emission Limit:** 4.56 g/hp-hr (6.2 g/kW-hr) 43.55 lb/hr
			ULSD Emergency Generator (1,500 kW / 2,011.5 HP)	**Control Method:** Good combustion practices and low sulfur fuels **NOx Emission Limit:** 4.56 g/hp-hr (6.2 g/kW-hr) 20.22 lb/hr

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Emission Limits
Shintech Plaquemine Plant 4	PSD-LA-857 (12/16/2024)	LA-0403	Five (5) Diesel Emergency Generators (2,346 HP, each)	**Control Method:** None **NOx Emission Limit:** 18.41 lb/hr 6.40 g/kW-hr (4.71 g/hp-hr)
			One (1) Diesel Emergency Generator (2,012 HP)	**Control Method:** None **NOx Emission Limit:** 15.79 lb/hr 0.51 tons/year 6.40 g/kW-hr (4.71 g/hp-hr)
XCEL Energy Blue Lake	13900010-105 (08/07/2024)	MN-0095	Three (3) ULSD Emergency Generators (1,049 HP, each)	**Control Method:** Emergency classification, hourly restriction, and NSPS compliance **NOx Emission Limit:** 4.80 g/hp-hr (6.5 g/kW-hr) 11.03 lb/hr
Mitsubishi Chemical America, Inc. MCA Geimar Site	PSD-LA-850 (07/24/2024)	LA-0406	Diesel Emergency Generator (1,140 HP)	**Control Method:** Proper equipment design and good combustion practices, use ultra-low sulfur diesel as fuel, low emission combustion **NOx Emission Limit:** 4.80 g/hp-hr (6.5 g/kW-hr) NMEHC + NOx
Wabash Valley Resources, LLC	167-45208-00091 (01/11/2024)	IN-0371	Diesel Emergency Generator (2,000 kW / 2,682 HP)	**Control Method:** Good combustion practices **NOx Emission Limit:** 3.81 g/hp-hr (5.18 g/kW-hr) Only NOx
			Diesel Emergency Generator (1,000 kW)	**Control Method:** Good combustion practices **NOx Emission Limit:** 3.81 g/hp-hr (5.18 g/kW-hr) Only NOx
Koch Methanol (KME) Facility	PSD-LA-851 (12/20/2023)	LA-0401	Two (2) Diesel Emergency Generators (2,923 HP)	**Control Method:** None **NOx Emission Limit:** 28.48 lb/hr *(converts to 4.4 g/hp-hr or 6.0 g/kW-hr)*
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Diesel Emergency Generator (1,490 HP)	**Control Method:** Good combustion practices and combusting clean fuels **NOx Emission Limit:** 4.8 g/hp-hr (6.5 g/kW-hr) 500 hr/year (rolling)
Maple Creek Energy LLC	T153-45909-00056 (06/19/2023)	IN-0365	Emergency Diesel Generator (2,012 HP)	**Control Method:** None **Emission Limit:** 4.8 g/hp-hr (6.5 g/kW-hr) for NMHC+NOx
Nucor Steel	107-45480-00038 (03/30/2023)	IN-0359	Diesel Emergency Generator (3,000 HP)	**Control Method:** Certified engine **NOx Emission Limit:** 4.8 g/hp-hr (6.5 g/kW-hr)

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Emission Limits
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	Two (2) Emergency Ultra-Low Sulfur Diesel Engines (1250 kW / 1676.3 HP, each)	**Control Method:** None **NOx Emission Limit:** 6.40 g/kW-hr (4.71 g/hp-hr) This limit includes NMHC+NOx
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Diesel Emergency Generator (1,341 HP)	**Control Method:** Good combustion practices **NOx Emission Limit:** 6.40 g/hp-hr (8.70 g/kW-hr) This limit is actually in NMHC+NOx
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/03/2022)	MI-0452	Diesel Emergency Generator (1,341 HP)	**Control Method:** Good combustion practices **NOx Emission Limit:** 6.40 g/hp-hr (8.70 g/kW-hr) This limit is actually in NMHC+NOx
Magnolia Power LLC- Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Diesel Emergency Generator (2,937 HP)	**Control Method:** Good combustion practices and use of ultra-low sulfur diesel fuel **NOx Emission Limit:** 4.80 g/hp-hr (6.53 g/kW-hr) This limit is actually in NMHC+NOx
Mountain State Clean Energy LLC Maidsville	R14-0038 (01/05/2022)	WV-0033	Emergency Generator (2,100 HP)	**Control Method:** Combustion control (retarded timing and/or lean burn) **NOx Emission Limit:** 24.60 lb/hr 6.40 g/kW-hr (4.71 g/hp-hr) NMHC+NOx
Shady Hills Energy Center LLC	1010524-003-AC (PSD-FL-444A) (06/07/2021)	FL-0371	Diesel Emergency Generator (1500 kW / 2,011.5 HP)	**Control Method:** NA **NOx Emission Limit:** 6.40 g/kW-hr (4.71 g/hp-hr) for NMHC and NOx
Nucor Steel Gallatin, LLC	V-20-015 (04/19/2021)	KY-0115	Two (2) Emergency Generators (2,937 HP)	**Control Method:** Good Combustion and Operating Practices (GCOP) Plan **NOx Emission Limit:** 4.80 g/hp-hr (6.53 g/kW-hr) NMHC+NOx
			One (1) Emergency Generator (2,922 HP)	**Control Method:** Good Combustion and Operating Practices (GCOP) Plan **NOx Emission Limit:** 4.80 g/hp-hr (6.53 g/kW-hr) NMHC+NOx
Arauco North America	29-16E (12/18/2020)	MI-0448	1,500 kW Emergency Diesel Generator (1,500 kW / 2,011.5 HP) (500 hr/year)	**Control Method:** Certified Engines, Limited Operating Hours **NOx Emission Limit:** 21.20 lb/hr *(converts to 4.8 g/hp-hr or 6.5 g/kW-hr)*

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.

Hybar (AR-0191) proposes a more stringent NOx emission limit based on vendor emissions data, of 3.9 g/bhp-hr with good operating practices, limited hours of operation, and compliance with NSPS Subpart IIII. 40 CFR 60, Subpart IIII establishes an NMHC + NOx emission limit of 4.8 g/hp-hr for engines with a maximum power of greater than 750 HP.

Maple Creek Energy I LLC is proposing compliance with the 40 CFR 60 Subpart IIII limits.

Step 5: Select BACT (NOx)

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the diesel-fired emergency generator (EG) shall be as follows:

(1) NMHC+NOx emissions from the diesel-fired emergency generator (EG) shall not exceed 4.8 g/hp-hr.

(2) NMHC+NOx emissions from the diesel-fired emergency generator (EG) shall not exceed 21.29 lb/hr.

(3) NOx emissions shall be controlled by the use of state-of-the-art combustion design and good combustion practices.

CO BACT Determination: Diesel-Fired Emergency Generator

Step 1: Identify Potential Control Technologies (CO)

Carbon monoxide (CO) emissions are formed during combustion processes because of incomplete combustion of carbon in the fuel. This occurs if there is a lack of available oxygen near the fuel molecule during combustion, if the gas temperature is too low, or if the residence time is too short.

Decreases in CO emissions are generally seen through proper engine maintenance and good combustion practices. Add-on controls for CO emissions from internal combustion engines include nonselective catalytic reduction, diesel oxidation catalysts, diesel particulate filters, and lean NOx catalysts. These are discussed below:

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.

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 CO_2 and water. CO emissions can be reduced by 70-99%.

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. CO emissions can be reduced by 90%.

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 Catalysts are also capable of reducing CO emissions by around 60%.

Combustion Design Controls
CO emissions are caused by 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 CO and unburned hydrocarbons that exit with the exhaust. CO formation can be minimized by improving the fuel air mixing through enhanced fuel injection systems, air management systems, combustion system designs, and pre-mixed diesel combustion.

Step 2: Eliminate Technically Infeasible Options (CO)

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 water pump engine. No other control options are being eliminated due to technical infeasibility.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness (CO)

Control/Method	***% Reduction***
Diesel Oxidation Catalyst	70-99%
Diesel Particulate Filter	90%
Lean NOx Catalyst	60%
Good Combustion Practices	Varies

Step 4: Evaluate the Most Effective Controls and Document the Results (CO)

The following table summarizes other BACT determinations for emergency diesel-fired internal combustion engines and generators that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) under Process Type Code 17.110 (Large Internal Combustion Engines >500 HP - Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel)), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date. Fire pump engines were excluded from this as not comparable as supported by the EPA developing different limits for fire pumps in 40 CFR 60, Subpart IIII.

Summary of RBLC Database Review - Large Internal Combustion Engines - Diesel Fuel

Facility	**Permit Number & Date**	**RBLC ID #**	**Emission Unit**	**CO Emission Limits**
Maple Creek Energy I LLC	Proposed	--	Diesel-fired Emergency Generator (2,012 HP)	**Control Method:** State-of-the-art combustion design and good combustion practices **CO Emission Limit:** 2.61 g/hp-hr *(converts to 3.55 g/kW-hr)* 11.58 lb/hr
Maple Creek Energy I LLC	Existing T153-45909-00056 (06/19/2023)	IN-0365	Emergency Diesel Generator (2,012 HP)	**Control Method:** None **CO Emission Limit:** 2.60 g/hp-hr *(converts to 3.54 g/kW-hr 11.53 lb/hr)*
Maple Creek Energy II LLC	Proposed	--	Diesel-fired Emergency Generator (2,012 HP)	**Control Method:** State-of-the-art combustion design and good combustion practices **CO Emission Limit:** 2.61 g/hp-hr *(converts to 3.55 g/kW-hr)* 11.58 lb/hr
Hybar	2470-AOP-R2	AR-01-91	Emergency Generators	**Control Method:**

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO Emission Limits
	(10/02/2025)		(2,700 kW / 3,620 HP, each)	Good operating practices and limited hours of operation **CO Emission Limit:** 0.90 g/hp-hr *(converts to 1.22 g/kW-hr and 7.18 lb/hr)* *(Emission limit based on vendor data.)*
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	Four (4) Diesel Black Start Emergency Generators (3,000 kW / 4,023 HP, each)	**Control Method:** Good combustion practices, low sulfur fuel, and limited operating hours **CO Emission Limit:** 2.60 g/hp-hr *(converts to 3.54 g/kW-hr)* 24.83 lb/hr
			ULSD Emergency Generator (1,500 kW / 2,011.5 HP)	**Control Method:** Good combustion practices and low sulfur fuels **CO Emission Limit:** 2.60 g/hp-hr *(converts to 3.54 g/kW-hr)* 11.53 lb/hr
Duke Energy, Indiana, Inc. - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	Emergency Generators (2,000 HP)	**Control Method:** Good combustion practices **CO Emission Limit:** 2.61 g/hp-hr *(converts to 3.55 g/kW-hr and 11.51 lb/hr)*
Shintech Plaquemine Plant 4	PSD-LA-857 (12/16/2024)	LA-0403	Five (5) Diesel Emergency Generators (2,346 HP, each)	**Control Method:** None **CO Emission Limit:** 13.50 lb/hr 3.50 g/kW-hr *(converts to 2.57 g/hp-hr)*
			One (1) Diesel Emergency Generator (2,012 HP)	**Control Method:** None **CO Emission Limit:** 11.57 lb/hr 0.38 tons/year 3.50 g/kW-hr *(converts to 2.57 g/hp-hr)*
XCEL Energy Blue Lake	13900010-105 (08/07/2024)	MN-0095	Three (3) ULSD Emergency Generators (1,049 HP, each)	**Control Method:** Emergency classification, hourly restriction, good combustion practices, and NSPS compliance **CO Emission Limit:** 2.60 g/hp-hr *(converts to 3.54 g/kW-hr)* 6.03 lb/hr
Mitsubishi Chemical America, Inc. MCA Geimar Site	PSD-LA-850 (07/24/2024)	LA-0406	Diesel Emergency Generator (1,140 HP)	**Control Method:** Proper equipment design and good combustion practices, use ultra-low sulfur diesel as fuel, low emission combustion **CO Emission Limit:** 2.60 g/hp-hr *(converts to 3.54 g/kW-hr and 6.53 lb/hr)*
Koch Methanol (KME) Facility	PSD-LA-851 (12/20/2023)	LA-0401	Two (2) Diesel Emergency Generators (2,923 HP)	**Control Method:** None **CO Emission Limit:** 2.90 lb/hr *(converts to 0.45 g/hp-hr and 0.61 g/kW-hr)*
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Diesel Emergency Generator (1,490 HP)	**Control Method:** Good combustion practices which include operational and design elements **CO Emission Limit:** 2.60 g/hp-hr *(converts to 3.54 g/kW-hr and 8.54 lb/hr)* 500 hr/year (rolling)

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO Emission Limits
Nucor Steel	107-45480-00038 (03/30/2023)	IN-0359	Diesel Emergency Generator (3,000 HP)	**Control Method:** Oxidation catalyst and certified engine **CO Emission Limit:** 2.61 g/hp-hr *(converts to 3.55 g/kW-hr and 17.26 lb/hr)*
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	Two (2) Emergency Ultra-Low Sulfur Diesel Engines (1250 kW / 1676.3 HP, each)	**Control Method:** None **CO Emission Limit:** 3.50 g/kW-hr *(converts to 2.57 g/hp-hr and 9.50 lb/hr)*
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Diesel Emergency Generator (1,341 HP)	**Control Method:** Good combustion practices **CO Emission Limit:** 3.50 g/kW-hr *(converts to 2.57 g/hp-hr and 7.60 lb/hr)*
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/03/2022)	MI-0452	Diesel Emergency Generator (1,341 HP)	**Control Method:** Good combustion practices **CO Emission Limit:** 3.50 g/kW-hr *(converts to 2.57 g/hp-hr 7.60 lb/hr)*
Magnolia Power LLC- Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Diesel Emergency Generator (2,937 HP)	**Control Method:** Good combustion practices and the use of ultra-low sulfur diesel fuel **CO Emission Limit:** 2.60 g/hp-hr *(converts to 3.54 g/kW-hr and 16.83 lb/hr)*
Mountain State Clean Energy LLC Maidsville	R14-0038 (01/05/2022)	WV-0033	Emergency Generator (2,100 HP)	**Control Method:** Good combustion practices with oxidation catalyst, certified engine **CO Emission Limit:** 1.94 lb/hr 0.41 g/kW (0.30 g/hp) NMHC+NOx 3.50 g/kW-hr (2.57 g/hp-hr) NMHC+NOx
Shady Hills Energy Center LLC	1010524-003-AC (PSD-FL-444A) (06/07/2021)	FL-0371	Diesel Emergency Generator (1500 kW / 2,011.5 HP)	**Control Method:** None **CO Emission Limit:** 3.50 g/kW-hr *(converts to 2.57 g/hp-hr and 11.40 lb/hr)*
Nucor Steel Gallatin, LLC	V-20-015 (04/19/2021)	KY-0115	Two (2) Emergency Generators (2,937 HP)	**Control Method:** Good Combustion and Operating Practices (GCOP) Plan **CO Emission Limit:** 2.60 g/hp-hr *(converts to 3.54 g/kW-hr and 16.83 lb/hr)*
			One (1) Emergency Generator (2,922 HP)	**Control Method:** Good Combustion and Operating Practices (GCOP) Plan **CO Emission Limit:** 2.60 g/hp-hr *(converts to 3.54 g/kW-hr and 16.75 lb/hr)*
Arauco North America	29-16E (12/18/2020)	MI-0448	Emergency Diesel Generator (1,500 kW / 2,011.5 HP) (500 hr/year)	**Control Method:** Good Design and Combustion Practices **CO Emission Limit:** 3.50 g/kW-hr *(converts to 2.57 g/hp-hr)* 11.60 lb/hr

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. Maple Creek Energy I LLC is proposing compliance with the 40 CFR 60 Subpart IIII limits.

Step 5: Select BACT (CO)

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the diesel-fired emergency generator (EG) shall be as follows:

(1) CO emissions from the diesel-fired emergency generator (EG) shall not exceed 2.61 g/hp-hr.

(2) CO emissions from the diesel-fired emergency generator (EG) shall not exceed 11.58 lb/hr.

(3) CO emissions shall be controlled by the use of state-of-the-art combustion design and good combustion practices.

SO_2/H_2SO_4 BACT Determination: Diesel-Fired Emergency Generator

Step 1: Identify Potential Control Technologies (SO_2)

Sulfur dioxide emissions produced by internal combustion engines result from the oxidation of sulfur in the fuel rather than from combustion variables. Therefore, the sulfur content of the fuel is the biggest factor for SO_2 emissions. No add-on controls are typically used to control SO_2 emissions from these types of engines and will not be considered in this review.

(a) Fuel Choice and Usage Limitations

Most of the sulfur present in fuel is oxidized to SO_2. Therefore, choosing a fuel with a lower sulfur content will result in lower SO_2 emissions. The emergency engines are existing units and are diesel engines. Therefore, no other types of fuel, such as natural gas, will be considered. However, these types of engines can run on low sulfur diesel fuel (0.05% sulfur) and ultra-low sulfur diesel fuel (0.0015% sulfur), which provide for lower SO2 emissions. Additionally, restrictions on the amount of fuel or hours of operation can further limit all emissions.

Step 2: Eliminate Technically Infeasible Options (SO_2)

The only control option for the emergency fire water pump engine is fuel choice and usage limitations.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness (SO_2)

Control/Method	***% Reduction***
Sulfur Content of Fuel / Fuel Use Limitations	Varies

Step 4: Evaluate the Most Effective Controls and Document the Results (SO_2)

The following table summarizes other BACT determinations for emergency diesel-fired internal combustion engines and generators that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) under Process Type Code 17.110 (Large Internal Combustion Engines >500 HP - Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel)), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date. Fire pump engines were excluded from this as not comparable as supported by the EPA developing different limits for fire pumps in 40 CFR 60, Subpart IIII.

Summary of RBLC Database Review - Large Internal Combustion Engines - Diesel Fuel

Facility	Permit Number & Date	RBLC ID #	Emission Unit	SO_2/H_2SO_4 Emission Limits
Maple Creek Energy I LLC	Proposed	--	Diesel-fired Emergency Generator (2,012 HP)	**Control Method:** Only use ultra-low sulfur diesel fuel (ULSD)(0.0015% S) **SO_2 Emission Limit:** 0.0016 lb/MMBtu **No H_2SO_4 Emission Limit**
Hybar	2470-AOP-R2 (10/02/2025)	AR-01-91	Emergency Generators (2,700 kW / 3,620 HP each)	**Control Method:** Good operating practices and limited hours of operation **No H_2SO_4 Emission Limit** **SO_2 Emission Limit:** 15.00 ppm or less S in fuel *(converts to 0.02 lb/MMBtu)*
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Diesel Emergency Generator (1,490 HP)	**Control Method:** Good combustion practices and combusting low sulfur fuel. Sulfur content of diesel fuel oil fired may not exceed 15 ppm **No SO_2 Emission Limit** **H_2SO_4 Emission Limit:** 500 hours/year (rolling)
Maple Creek Energy LLC	T153-45909-00056 (06/19/2023)	IN-0365	Emergency Diesel Generator (2,012 HP)	**Control Method:** Low-Sulfur Fuel (sulfur content shall not exceed 0.0015%) and good combustion design **SO_2 Emission Limit:** 0.0016 lb/MMBtu
Nucor Steel	107-45480-00038 (03/30/2023)	IN-0359	Diesel Emergency Generator (3,000 HP)	**Control Method:** Ultra-low sulfur diesel fuel (0.0015% S) **No SO_2 Emission Limit**
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Diesel Emergency Generator (1,341 HP)	**Control Method:** Good combustion practices **SO_2 Emission Limit:** 15.0 ppm (0.0015% by weight) *(converts to 0.02 lb/MMBtu)*
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/03/2022)	MI-0452	Diesel Emergency Generator (1,341 HP)	**Control Method:** Good combustion practices **SO_2 Emission Limit:** 15.0 ppm (0.0015% by weight) *(converts to 0.02 lb/MMBtu)*
Shady Hills Energy Center LLC	1010524-003-AC (PSD-FL-444A) (06/07/2021)	FL-0371	Diesel Emergency Generator (1,500 kW / 2,011.5 HP)	**Control Method:** None **SO_2 Emission Limit:** 15 ppm S in Fuel *(converts to 0.02 lb/MMBtu)* Use only ULSD fuel

Maple Creek Energy I LLC proposes the use of ultra-low sulfur diesel fuel with a maximum of 0.0015% sulfur content and limiting SO_2 emissions to less than 0.0016 lb/MMBtu as BACT for SO_2. No add-on controls were seen in the review of other similar BACT determinations. Most BACT determinations for SO_2 involve limiting the sulfur content of the fuel based on the requirements of 40 CFR 60, Subpart IIII. Additionally, some determinations include pound per hour and/or ton per year limits or other limitations on usage or hours of operation, but add-on reduction technology is not required.

The proposed BACT meets the most stringent BACT; therefore, no further evaluation of this operation is required and an economic, energy, or environmental impact analysis is not required as part of the SO_2 BACT evaluation for this unit.

Step 5: Select BACT (SO_2)

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (BACT) for H_2SO_4 for the diesel-fired emergency generator (EG) shall be as follows:

(a) Only ultra-low sulfur diesel (ULSD) (0.0015% S) shall be used in the diesel-fired emergency generator (EG).

GHG BACT Determination: Diesel-Fired Emergency Generator

Step 1: Identify Potential Control Technologies (CO_{2e})

CO_2 is by far the dominant GHG from this source. CH_4 and N_2O are present only in very small amounts, are incidental to combustion, and trend with the CO_2 emissions. There are no known supplemental controls for N_2O or methane emissions from diesel engines. To the extent measures are identified that reduce CO_2, the other GHGs may be also reduced accordingly. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

Diesel fuel is used because it is an independent source of fuel not related to the operation of the facility. As such, it is the most reliable fuel source and its use in this application is fundamental to meeting power and water requirements in an emergency situation. For this reason, it is the most common fuel used for these types of emergency backup applications.

GHG control possibilities identified and addressed in this BACT analysis for these small engines are:

(1) Good engineering design and Fuel-efficient design; and

(2) Post combustion carbon capture

Step 2: Eliminate Technically Infeasible Options (CO_{2e})

Good Engineering Design and Fuel-Efficient Design
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. This Diesel engine is built with automatic control of the air to fuel ratio that ensures that it operates 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 generators at this source.

Carbon Capture
Post-combustion CO_2 capture is a relatively new concept. In EPA's recent GHG BACT guidance, EPA takes the position that, "*for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams".* The source combustion sources such as the emergency engines do not fit into either of the above categories called out by EPA's guidance document as appropriate for consideration of CCS. The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above examples. However, relevant guidance can be discerned from the Appendix F to the above referenced US EPA guidance document, which presents an example GHG BACT analysis for a 250 MMBtu/hr natural gas fired boiler. In this US EPA boiler example, carbon capture isn't listed or considered in the BACT analysis as a potentially available option. The absence of a discussion of carbon capture in this 250 MMBtu/hr boiler example is consistent with the fact that carbon capture is extremely expensive, has numerous technical challenges, and is currently only being contemplated on very large or very concentrated CO_2 sources. In stark contrast, the source's Project miscellaneous combustion sources are an order of magnitude smaller than EPA's example, and

significantly smaller still than the categories that US EPA's guidance document suggests should consider CCS.

A CO_2 capture system for the emergency diesel engines is not a reasonable BACT option because the capture of CO_2 from combustion exhaust of small sources is significantly more difficult than from the types of industrial gas streams that EPA references as having potential for CCS. The increased difficulty is due to four factors: low CO_2 concentration, low pressure, low quantity of CO_2 available for capture, and the variability of load for these units.

The low concentration and low pressure of the exhausts from these processes complicate the absorption and desorption of the CO_2, which increases the energy required. Also, a low-pressure absorption system creates a low pressure CO_2 stream which requires a very high energy demand for compression prior to transport. All these factors make the application of CO_2 capture on any small combustion exhaust extremely difficult and expensive. Additionally, the cost of capturing CO_2 for smaller sources is more expensive due to the lack of economy-of-scale. Further, the emergency engines are intermittent sources, which would further increase the cost and difficulty of implementing any control.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of post-combustion capture of CO_2 is not a technically feasible option for the Emergency generators at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness (CO_{2e})

The only feasible, applicable and available control technology identified to reduce greenhouse gases from the emergency diesel generators engines is to utilize good engineering design and fuel-efficient design.

Step 4: Evaluate the Most Effective Controls and Document the Results (CO_{2e})

The following table summarizes other BACT determinations for emergency diesel-fired internal combustion engines and generators that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) under Process Type Code 17.110 (Large Internal Combustion Engines >500 HP - Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel)), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date. Fire pump engines were excluded from this review.

Summary of RBLC Database Review - Large Internal Combustion Engines - Diesel Fuel

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO_{2e} Emission Limits
Maple Creek Energy I LLC	Proposed	--	Diesel-fired Emergency Generator (2,012 HP)	**Control Method:** Good engineering design and fuel-efficient design **CO_{2e} Emission Limit:** 125 tons per twelve (12) consecutive month period
Maple Creek Energy I LLC	Existing T153-45909-00056 (06/19/2023)	IN-0365	Emergency Diesel Generator (2,012 HP)	**Control Method:** Good engineering design and fuel-efficient design **CO_{2e} Emission Limit:** 625 tons/year
Maple Creek Energy II LLC	Proposed	--	Diesel-fired Emergency Generator (2,012 HP)	**Control Method:** Good engineering design and fuel-efficient design

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO_{2e} Emission Limits
				CO_{2e} Emission Limit: 125 tons per twelve (12) consecutive month period
Hybar	2470-AOP-R2 (10/02/2025)	AR-01-91	Emergency Generators (2,700 kW / 3,620 HP, each)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 164 lb/MMBtu
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	Four (4) Diesel Black Start Emergency Generators (3,000 kW / 4,023 HP, each)	**Control Method:** Good engineering design fuel efficient design, and limited operating hours **CO_{2e} Emission Limit:** 1,115,606 tons/year (rolling) from entire source
			ULSD Emergency Generator (1,500 kW / 2,011.5 HP)	**Control Method:** Good engineering design fuel efficient design, and limited operating hours **CO_{2e} Emission Limit:** 1,115,606 tons/year (rolling) from entire source
Duke Energy, Indiana, Inc. - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	Emergency Generators (2,000 HP)	**Control Method:** Good combustion practices **No GHG Emission Limit**
Shintech Plaquemine Plant 4	PSD-LA-857 (12/16/2024)	LA-0403	Five (5) Diesel Emergency Generators (2,346 HP, each)	**Control Method:** Improved Combustion Measures, Insulation, and Minimization of Air Infiltration **No GHG Emission Limit**
			One (1) Diesel Emergency Generator (2,012 HP)	**Control Method:** Improved Combustion Measures, Insulation, and Minimization of Air Infiltration **CO_{2e} Emission Limit:** 75 tons/year
XCEL Energy Blue Lake	13900010-105 (08/07/2024)	MN-0095	Three (3) ULSD Emergency Generators (1,049 HP, each)	**Control Method:** Energy classification, hourly restriction, good combustion practices, and NSPS compliance **CO_{2e} Emission Limit:** 314 tons/year (rolling)
Mitsubishi Chemical America, Inc. MCA Geimar Site	PSD-LA-850 (07/24/2024)	LA-0406	Diesel Emergency Generator (1,140 HP)	**Control Method:** Proper equipment design and good combustion practices, use ultra-low sulfur diesel as fuel **CO_{2e} Emission Limit:** 1.16 g/hp-hr
Wabash Valley Resources, LLC	167-45208-00091 (01/11/2024)	IN-0371	Diesel Emergency Generator (2,000 kW / 2,682 HP)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 778 tons/year (rolling)
			Diesel Emergency Generator (1,000 kW / 1,341 HP)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 389 tons/year (rolling)
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Diesel Emergency Generator (1,490 HP)	**Control Method:** Certified engine, efficient engine design, minimizing hours of operation **CO_{2e} Emission Limit:** 500 hours/year (rolling)
Nucor Steel	107-45480-00038 (03/30/2023)	IN-0359	Diesel Emergency Generator (3,000 HP)	**Control Method:** Good engineering design and

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO_{2e} Emission Limits
				manufacturer's recommended operating and maintenance procedures **CO_{2e} Emission Limit:** 163.6 lb/MMBtu 920.0 tons/year
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	Two (2) Emergency Ultra-Low Sulfur Diesel Engines (1250 kW / 1676.3 HP, each)	**Control Method:** None **CO_{2e} Emission Limit:** 508 tons/year (each engine)
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Diesel Emergency Generator (1,341 HP)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 383 tons/year (rolling)
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/03/2022)	MI-0452	Diesel Emergency Generator (1,341 HP)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 383 tons/year (rolling)
Magnolia Power LLC- Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Diesel Emergency Generator (2,937 HP)	**Control Method:** Good combustion practices and the use of ultra-low sulfur diesel fuel **CO_{2e} Emission Limit:** 74.21 kg/MMBtu 163.61 lb/MMBtu
Arauco North America	29-16E (12/18/2020)	MI-0448	Emergency Diesel Generator (1,500 kW / 2,011.5 HP) (500 hr/year)	**Control Method:** Good combustion and design practices **CO_{2e} Emission Limit:** 590 tons/year (rolling) 500 hours/year operation

This project includes one (1) diesel-fired 2,012 hp standby emergency generator. The engine is expected to operate less than 500 hours per year. That use is associated with assuring its readiness in an emergency. This emergency diesel-fired engine will have the potential to emit greenhouse gases (CO_2, CH_4, and N_2O) because it will combust a hydrocarbon fuel. However, because the normal use is limited to routine maintenance, inspection and testing, the total emissions are very small (less than 600 tons CO_2e/yr, each).

Step 5: Select BACT (CO_{2e})

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for the GHG for the diesel-fired emergency generator (EG):

(1) The use of a good engineering design and fuel-efficient design; and

(2) CO_2e emissions from the diesel-fired emergency generator (EG) shall not exceed 125 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

Summary of Emergency Diesel Fire Pump Engine

PM/PM_{10}/$PM_{2.5}$ BACT Determination: Diesel-Fired Emergency Fire Pump Engine

Step 1: Identify Potential Control Technologies (PM/PM_{10}/$PM_{2.5}$)

Particulate emissions from internal combustion engines primarily result from incomplete combustion. Ash and metallic additives in the fuel may also contribute to the particulate content of the exhaust. Particulate may be generated when the temperature is not high enough to ignite the fuel, when lubricating oil leaks and is partially burned, and when combustion is oxygen deficient. Higher sulfur content fuels tend to increase particulate emissions due to the formation of sulfates during the oxidation of SO_2, which are fine particulates.

Decreases in particulate emissions are generally seen through proper engine maintenance and good combustion practices. Add-on controls for particulate emissions from internal combustion engines include oxidation catalysts and diesel particulate filters. These are discussed below:

Diesel Oxidation Catalysts
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 CO_2 and water. The level of particulate control is a function of the soluble organic fraction of particulate. The soluble organic fraction can be reduced by as much as 90%. Total particulate emissions may be reduced by up to 40-50%, although 20-35% is typical.

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 build up 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. Collection efficiencies of filters range from 50-90%. Catalytic coatings on diesel particulate filters can also reduce CO and VOC emissions.

Good Combustion Practices
Organic particulate matter emissions are caused through incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form in the fuel injection plume that cause unburned fuel to pyrolyze at the high engine temperature and form soot. Soot formation can be minimized by improving the fuel air mixing through enhanced fuel injection systems, air management systems, combustion system designs, and pre-mixed diesel combustion.

Fuel Choice and Usage Limitations
Most of the sulfur present in fuel is oxidized to SO_2. Through further reactions, sulfates, which are fine particles, can also form. Therefore, higher sulfur fuels can lead to higher particulate emissions. By limiting the sulfur content in fuel, both SO_2 and particulate emissions can be reduced. Additionally, restrictions on the amount of fuel or hours of operation can further limit all emissions.

Step 2: Eliminate Technically Infeasible Options (PM/PM_{10}/$PM_{2.5}$)

While add-on controls are not typically used for emergency fire pump engines, no controls are being eliminated based on technical infeasibility.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness (PM/PM_{10}/$PM_{2.5}$)

Control/Method	***% Reduction***
Diesel Particulate Filters	50-90%
Diesel Oxidation Catalyst	20-50%
Good Combustion Practices	Varies
Sulfur Content of Fuel / Fuel Use Limitations	Varies

Step 4: Evaluate the Most Effective Controls and Document the Results (PM/PM_{10}/$PM_{2.5}$)

The following table summarizes other BACT determinations for emergency diesel-fired fire pump engines that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) under Process Type Code 17.210 (Small Internal Combustion Engines <500 HP - Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel)), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date. Only fire pump engines and water pumps are included in this table; emergency generators were excluded from this evaluation.

Summary of RBLC Database Review - Small Internal Combustion Engines - Diesel Fuel

Facility	Permit Number & Date	RBLC ID #	Emission Unit	$PM/PM_{10}/PM_{2.5}$ Emission Limits
Maple Creek Energy I LLC	Proposed	--	Diesel-fired Emergency Fire Pump Engine (420 HP)	**Control Method:** State-of-the-art combustion design and good combustion practices **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.20 g/kW-hr *(converts to 0.15 g/hp-hr)* 0.14 lb/hr
Maple Creek Energy I LLC	Existing T153-45909-00056 (06/19/2023)	IN-0365	Diesel Emergency Fire Pump (420 bHP)	**Control Method:** None **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.20 g/kW-hr *(converts to 0.15 g/hp-hr and 0.14 lb/hr)*
Maple Creek Energy II LLC	Proposed	--	Diesel-fired Emergency Fire Pump Engine (420 HP)	**Control Method:** State-of-the-art combustion design and good combustion practices **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.20 g/kW-hr *(converts to 0.15 g/hp-hr)* 0.14 lb/hr
Hybar	2470-AOP-R2 (10/02/2025)	AR-0191	Diesel Emergency Water Pumps (376 HP, each)	**Control Method:** Good operating practices, limited hours of operation **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 1.00 g/hp-hr *(converts to 1.36 g/kW-hr and 0.83 lb/hr)*
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	ULSD Emergency Fire Water Pump (282 bhp)	**Control Method:** Good combustion practices, low sulfur fuel **PM Emission Limit:** 0.15 g/hp-hr *(converts to 0.20 g/kW-hr)* 0.09 lb/hr **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.17 g/hp-hr *(converts to 0.23 g/kW-hr)* 0.11 lb/hr
Duke Energy Indiana, Inc. - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	Diesel Emergency Fire Pump (300 HP)	**Control Method:** Good combustion practices **PM Emission Limit:** 0.15 g/hp-hr *(converts to 0.20 g/kW-hr and 0.10 lb/hr)*
Shintech Plaquemine Plant 4	PSD-LA-857 (12/16/2024)	LA-0403	Three (3) Diesel Emergency Fire Pumps (200 HP, each)	**Control Method:** None **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.07 lb/hr 0.20 g/kW-hr *(converts to 0.15 g/hp-hr)*
Lansing Board of Water and Light- Delta Energy Park	71-24 (06/27/2024)	MI-0459	Diesel Fire Pump (500 bHP)	**Control Method:** Good combustion practice, use of ULSD **PM Emission Limit:** 0.20 g/kW-hr *(converts to 0.15 g/hp-hr and 0.17 lb/hr)* **$PM_{10}/PM_{2.5}$ Emission Limit:** 1.10 lb/hr *(converts to 1.36 g/kW-hr or 0.99 g/hp-hr)*

Facility	Permit Number & Date	RBLC ID #	Emission Unit	$PM/PM_{10}/PM_{2.5}$ Emission Limits
Cronus Chemicals, LLC	19110020 (12/21/2023)	IL-0134	Firewater Pump Engine (369 HP)	**Control Method:** None **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.20 g/kW-hr *(converts to 0.15 g/hp-hr and 0.12 lb/hr)* 100 hours/year operational limit
Koch Methanol (KME) Facility	PSD-LA-851 (12/20/2023)	LA-0401	Firewater Pump Engines No. 1 and 2 (422 HP, each)	**Control Method:** None **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.20 lb/hr *(converts to 0.29 g/kW-hr or 0.21 g/hp-hr)*
			Firewater Pump Engine No. 3 (237 HP)	**Control Method:** None **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.06 lb/hr *(converts to 0.16 g/kW-hr or 0.11 g/hp-hr)*
Bunge Chevron AG Renewables, LLC / Destrehan Oil Processing Facility	PSD-LA-855 (12/13/2023)	LA-0402	Emergency Diesel Fire Pump Engine (200 HP)	**Control Method:** None **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.14 lb/hr hourly maximum 0.01 tons/year annual maximum 0.15 g/hp-hr *(converts to 0.20 g/kW-hr)*
Shell Chemical LP Geismar Plant	PSD-LA-647(M-9) (12/12/2023)	LA-0394	Two (2) Diesel Sump Pump Drivers (200 HP, each)	**Control Method:** Good operating practices, limited hours of operation **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.06 lb/hr 0.20 g/kW-hr *(converts to 0.15 g/hp-hr)* 100 hours/year
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Emergency Diesel Fire Pump (282 HP)	**Control Method:** Good operating practices, limited hours of operation, sulfur content of the diesel fuel oil fired may not exceed 15 ppm, unit shall be operating and maintained according to manufacturer's recommendations **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.15 g/hp-hr *(converts to 0.20 g/kW-hr and 0.09 lb/hr)* 500 hours/year (rolling)
Maple Creek Energy LLC	T153-45909-00056 (06/19/2023)	IN-0365	Diesel Emergency Fire Pump (420 bHP)	**Control Method:** None **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.20 g/kW-hr *(converts to 0.15 g/hp-hr and 0.14 lb/hr)*
Norfolk Crush, LLC	CP22-017 (11/21/2022)	NE-0064	Diesel Emergency Fire Water Pump Engine (510 HP)	**Control Method:** None **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.15 g/hp-hr *(converts to 0.20 g/kW-hr and 0.17 lb/hr)* 100 hours/year
Kronospan, LLC	301-0079 (09/21/2022)	AL-0337	Diesel Fire Pump (460 bHP)	**Control Method:** Catalyst, 500 hr/yr operational limit **PM Emission Limit:** 0.40 g/hp-hr 0.41 lb/hr 0.54 g/kW-hr
Intel Ohio Site	P0132323 (09/20/2022)	OH-0387	Diesel-Fired Emergency Fire Pump Engine (275 HP)	**Control Method:** Good combustion practices **PM Emission Limit:** 0.20 g/kW-hr *(converts to 0.15 g/hp-hr)* 0.60 lb/hr 0.2 tons/year (rolling) **$PM_{10}/PM_{2.5}$ Emission Limit:**

Facility	Permit Number & Date	RBLC ID #	Emission Unit	$PM/PM_{10}/PM_{2.5}$ Emission Limits
				0.60 lb/hr *(converts to 1.35 g/kW-hr or 0.99 g/hp-hr)* 0.20 tons/year (rolling)
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	ULSD Fire Water Pump Engine (320 HP)	**Control Method:** None **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.20 g/kW-hr *(converts to 0.15 g/hp-hr and 0.11 lb/hr)*
Alaska Gasline Development Corporation Liquefaction Plant	AQ1539CPT01 (07/07/2022)	AK-0088	Diesel Fire Pump Engine (575 HP)	**Control Method:** Good combustion practices, limited operation **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 0.19 g/hp-hr @ 15% O_2 *(converts to 0.26 g/kW-hr and 0.24 lb/hr)* 500 hours/year
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Diesel-Fired Emergency Fire Pump Engine (300 HP)	**Control Method:** Diesel particulate filter and good combustion practices **PM Emission Limit:** 0.15 g/hp-hr *(converts to 0.20 g/kW-hr and 0.10 lb/hr)* **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.66 lb/hr *(converts to 1.36 g/kW-hr and 1.00 g/hp-hr)*
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/23/2022)	MI-0452	Diesel-Fired Emergency Fire Pump Engine (300 HP)	**Control Method:** Diesel particulate filter and good combustion practices **PM Emission Limit:** 0.15 g/hp-hr *(converts to 0.20 g/kW-hr and 0.10 lb/hr)* **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.66 lb/hr *(converts to 1.36 g/kW-hr and 1.00 g/hp-hr)*
Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Emergency Diesel Fired Water Pump Engine (355 HP)	**Control Method:** Good combustion practices and use of ultra-low sulfur diesel fuel **$PM_{10}/PM_{2.5}$ Emission Limit:** 0.15 g/hp-hr *(converts to 0.20 g/kW-hr and 0.12 lb/hr)*
Big River Steel LLC	2445-AOP-R0 (01/31/2022)	AR-0173	Emergency Water Pumps	**Control Method:** Good operating practices and limited hours of operation **$PM/PM_{10}/PM_{2.5}$ Emission Limit:** 1.00 g/hp-hr *(converts to 1.36 g/kW-hr)*
Mountain State Clean Energy, LLC Maidsville	R14-0038 (01/05/2022)	WV-0033	ULSD Fire Water Pump (240 bHP)	**Control Method:** Clean fuels and good combustion practices **$PM_{2.5}$ Emission Limit:** 0.08 lb/hr 0.15 g/hp-hr *(converts to 0.20 g/kW-hr)*
Shady Hills Energy Center, LLC	1010524-003-AC (PSD-FL-444A) (06/07/2021)	FL-0371	Diesel Emergency Fire Pump (347 HP)	**Control Method:** None **PM Emission Limit:** 0.20 g/kW-hr *(converts to 0.15 g/hp-hr and 0.11 lb/hr)*
WPL - Riverside Energy Center	19-DMM-153 (02/28/2020)	LA-0370	Diesel-Fired Fire Pump Engine (290 HP)	**Control Method:** Good combustion practices, use diesel fuel oil with sulfur content of no greater than 0.0015% by weight **PM/PM_{10} Emission Limit:** 0.11 lb/hr *(converts to 0.23 g/kW-hr or 0.17 g/hp-hr)*

Maple Creek Energy I LLC proposes the use of state-of-the-art combustion design and emission limit of 0.20 g/kW-hr as BACT for PM, PM_{10}, and $PM_{2.5}$. No add-on controls were seen in the review of other similar BACT determinations. Additionally, based on conservatively low-cost estimates, neither a diesel particulate filter nor a diesel oxidation catalyst is economically feasible for controlling particulate emissions from the emergency fire water pump. Therefore, the Permittee has proposed the next best control methods.

Maple Creek Energy I LLC is proposing an PM, PM10, and PM2.5 emission limitation of 0.20 g/kW-hr, which is consistent with the 40 CFR 60 Subpart IIII limitation and with a majority of projects listed in RBLC, as well as use of state-of-the-art combustion design and good combustion practices. The proposed BACT limit will be considered as the top BACT for this unit and no further evaluation of this operation is required and an economic, energy, or environmental impact analysis is not required as part of the PM BACT evaluation for this unit.

Step 5: Select BACT (PM, PM_{10}, and $PM_{2.5}$)

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (BACT) for PM, PM_{10}, and $PM_{2.5}$ for the diesel-fired emergency fire water pump engine (FP) shall be as follows:

(1) PM, PM_{10}, and $PM_{2.5}$ emissions from the diesel-fired emergency fire water pump engine (FP) shall not exceed the values in the table below:

	PM	PM_{10}	$PM_{2.5}$
Emission Limit (g/kW-hr)	0.20	0.20	0.20
Emission Limit (lb/hr)	0.14	0.14	0.14

(2) PM, PM_{10}, and $PM_{2.5}$ emissions shall be reduced through the implementation of state-of-the-art combustion design and good combustion practices.

NOx BACT Determination: Diesel-Fired Emergency Fire Pump Engine

Step 1: Identify Potential Control Technologies (NOx)

During combustion processes, NOx emissions can form in three different ways: thermal NOx, fuel NOx, and prompt NOx. Thermal NOx occurs as a result of the reaction of nitrogen and oxygen in the combustion air, usually in the high temperature flame zone near the burners. Fuel NOx is a result of the reaction of any fuel-bound nitrogen compounds with oxygen during combustion. Prompt NOx occurs through early reactions of the nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NOx is usually small compared to thermal NOx emissions.

Decreases in NOx emissions are generally seen through proper engine maintenance and good combustion practices. Add-on controls for NOx emissions from internal combustion engines include selective catalytic reduction, nonselective catalytic reduction, and lean NOx catalysts. These are discussed below:

Selective Catalytic Reduction (SCR)

The SCR process chemically reduces the NOx molecule into molecular nitrogen and water vapor. A nitrogen-based reagent such as ammonia is injected into the exhaust gas stream upstream of a catalyst. The reagent reacts selectively with the NOx within a specific temperature range in the presence of the catalyst and oxygen to reduce the NOx to nitrogen and water. SCR is capable of NOx reduction efficiencies in the range of 80-95%.

The NOx reduction reaction is only effective within a given temperature range, depending on the waste gas composition and type of catalyst. Optimum temperatures range from 600-750 °F for conventional catalyst types and 470-510 °F for platinum catalysts. SCR systems are capable of reducing NOx in low-concentration waste streams (as low as 20 ppm). Above 850 °F, ammonia begins to be oxidized to form additional NOx. The optimal effectiveness is also dependent on the ammonia-to-NOx ratio, space velocity, the ratio of flue gas flow rate to catalyst volume, and residence time.

Nonselective Catalytic Reduction (NSCR)
Nonselective Catalytic Reduction also 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. NOx can be reduced by 80-95% under rich-burn conditions.

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 N_2. The zeolites provide sites to attract the hydrocarbons to facilitate the NOx reduction reactions. NOx reductions are in the range of 25-40%.

Good Combustion Practices
Maximum reduction of thermal NOx generation can be achieved by control of both the combustion temperature and the air-to-fuel ratio. Due to the high flame temperatures and pressures of internal combustion engines, the majority of NOx formed is thermal NOx. With diesel fuel, little fuel NOx is formed.

Combustion Controls may include exhaust gas recirculation, injection timing retard, air-to-fuel ratio, and water injection.

Step 2: Eliminate Technically Infeasible Options (NOx)

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 water pump engine. No other control options are being eliminated due to technical infeasibility.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness (NOx)

Control/Method	***% Reduction***
Selective Catalytic Reduction	80-95%
Lean NOx Catalyst	25-40%
Good Combustion Practices	Varies

Step 4: Evaluate the Most Effective Controls and Document the Results (NOx)

The following table summarizes other BACT determinations for emergency diesel-fired fire pump engines that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) under Process Type Code 17.210 (Small Internal Combustion Engines <500 HP - Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel)), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date. Only fire pump engines and water pumps are included in this table; emergency generators were excluded from this evaluation.

Summary of RBLC Database Review - Small Internal Combustion Engines - Diesel Fuel

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Emission Limits
Maple Creek Energy I LLC	Proposed	--	Diesel-fired Emergency Fire Pump Engine (420 HP)	**Control Method:** State-of-the-art combustion design and good combustion practices **NOx Emission Limit:** 4.0 g/kW-hr NOx + NMHC *(converts to 2.94 g/hp-hr)* 2.72 lb/hr
Maple Creek Energy I LLC	Existing T153-45909-00056 (06/19/2023)	IN-0365	Diesel Emergency Fire Pump (420 bHP)	**Control Method:** None **NOx Emission Limit:** 4.00 g/kW-hr *(converts to 2.94 g/hp-hr and 2.72 lb/hr)* 4.80 g/hp-hr NOx + NMHC *(converts to 6.53 g/kW-hr and 4.44 lb/hr)*
Maple Creek Energy II LLC	Proposed	--	Diesel-fired Emergency Fire Pump Engine (420 HP)	**Control Method:** State-of-the-art combustion design and good combustion practices **NOx Emission Limit:** 4.0 g/kW-hr NOx + NMHC *(converts to 2.94 g/hp-hr)* 2.72 lb/hr
Hybar	2470-AOP-R2 (10/02/2025)	AR-0191	Diesel Emergency Water Pumps (376 HP, each)	**Control Method:** Good operation practices, limited hours of operation **NOx Emission Limit:** 14.06 g/hp-hr *(converts to 19.12 g/kW-hr and 11.65 lb/hr)*
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	ULSD Emergency Fire Water Pump (282 bhp)	**Control Method:** Good combustion practices, low sulfur fuel **NOx Emission Limit:** 2.85 g/hp-hr *(converts to 3.87 g/kW-hr)* 1.77 lb/hr
Shintech Plaquemine Plant 4	PSD-LA-857 (12/16/2024)	LA-0403	Three (3) Diesel Emergency Fire Pumps (200 HP, each)	**Control Method:** None **NOx Emission Limit:** 0.98 lb/hr 4.00 g/kW-hr *(2.94 g/hp-hr)* NOx + NMHC
Lansing Board of Water and Light- Delta Energy Park	71-24 (06/27/2024)	MI-0459	Diesel Fire Pump (500 bHP)	**Control Method:** None **NOx Emission Limit:** 4.00 g/kW-hr NOx + NMHC *(converts to 2.94 g/hp-hr and 3.24 lb/hr)*
Cronus Chemicals, LLC	19110020 (12/21/2023)	IL-0134	Firewater Pump Engine (369 HP)	**Control Method:** None **NOx Emission Limit:** 4.00 g/kW-hr NOx + NMHC *(converts to 2.94 g/hp-hr and 2.39 lb/hr)* 100 hr/year operational limit
Koch Methanol (KME) Facility	PSD-LA-851 (12/20/2023)	LA-0401	Firewater Pump Engines No. 1 and 2 (422 HP, each)	**Control Method:** None **NOx Emission Limit:** 3.96 lb/hr *(converts to 5.79 g/kW-hr or 4.26 g/hp-hr)*
			Firewater Pump Engine No. 3 (237 HP)	**Control Method:** None **NOx Emission Limit:** 1.49 lb/hr *(converts to 3.88 g/kW-hr or 2.85 g/hp-hr)*

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Emission Limits
Shell Chemical LP Geismar Plant	PSD-LA-647(M-9) (12/12/2023)	LA-0394	Two (2) Diesel Sump Pump Drivers (200 HP, each)	**Control Method:** Good combustion practices **NOx Emission Limit:** 1.26 lb/hr 3.88 g/kW-hr *(converts to 2.85 g/hp-hr)*
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Emergency Diesel Fire Pump (282 HP)	**Control Method:** Good combustion practices and combusting clean fuels **NOx Emission Limit:** 3.00 g/hp-hr *(converts to 4.08 g/kW-hr and 1.87 lb/hr)* 500 hours/year (rolling)
Norfolk Crush, LLC	CP22-017 (11/21/2022)	NE-0064	Diesel Emergency Fire Water Pump Engine (510 HP)	**Control Method:** None **NOx Emission Limit:** 2.38 g/hp-hr *(converts to 3.24 g/kW-hr and 2.68 lb/hr)* 3.00 g/hp-hr NOx + NMHC *(converts to 4.08 g/kW-hr and 3.37 lb/hr)* 100 hours/year of operation
Kronospan, LLC	301-0079 (09/21/2022)	AL-0337	Diesel Fire Pump (460 bHP)	**Control Method:** Catalyst, 500 hr/yr operational limit **NOx Emission Limit:** 7.80 g/hp-hr *(10.5 g/kW-hr)* NOx + NMHC 7.12 lb/hr
Intel Ohio Site	P0132323 (09/20/2022)	OH-0387	Diesel-Fired Emergency Fire Pump Engine (275 HP)	**Control Method:** Good combustion practices **NOx Emission Limit:** 4.00 g/kW-hr *(2.94 g/hp-hr)* NOx + NMHC 8.50 lb/hr 2.1 tons/year (rolling)
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	ULSD Fire Water Pump Engine (320 HP)	**Control Method:** None **NOx Emission Limit:** 4.00 g/kW-hr *(2.94 g/hp-hr)* NOx + NMHC
Alaska Gasline Development Corporation Liquefaction Plant	AQ1539CPT01 (07/07/2022)	AK-0088	Diesel Fire Pump Engine (575 HP)	**Control Method:** Good combustion practices, limited operation **NOx Emission Limit:** 3.60 g/hp-hr *(4.89 g/kW-hr)* NOx + NMHC 500 hours/year
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Diesel-Fired Emergency Fire Pump Engine (300 HP)	**Control Method:** Good combustion practices **NOx Emission Limit:** 3.00 g/hp-hr *(4.08 g/kW-hr)* NOx + NMHC
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/23/2022)	MI-0452	Diesel-Fired Emergency Fire Pump Engine (300 HP)	**Control Method:** Good combustion practices **NOx Emission Limit:** 3.00 g/hp-hr *(4.08 g/kW-hr)* NOx + NMHC
Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Emergency Diesel Fired Water Pump Engine (355 HP)	**Control Method:** Good combustion practices and use of ultra-low sulfur diesel fuel **NOx Emission Limit:** 3.00 g/hp-hr *(4.08 g/kW-hr)* NOx + NMHC
Big River Steel LLC	2445-AOP-R0 (01/31/2022)	AR-0173	Emergency Water Pumps	**Control Method:** Good combustion practices and limited hours of operation **NOx Emission Limit:** 14.06 g/hp-hr *(converts to 19.12 g/kW-hr)*

Facility	Permit Number & Date	RBLC ID #	Emission Unit	NOx Emission Limits
Mountain State Clean Energy, LLC Maidsville	R14-0038 (01/05/2022)	WV-0033	ULSD Fire Water Pump (240 bHP)	**Control Method:** Combustion control (retarded timing and/or lean burn) **NOx Emission Limit:** 1.59 lb/hr 4.00 g/kW-hr *(2.94 g/hp-hr)* 4.00 g/kW-hr *(2.94 g/hp-hr)* NMHC + NOx
Shady Hills Energy Center, LLC	1010524-003-AC (PSD-FL-444A) (06/07/2021)	FL-0371	Diesel Emergency Fire Pump (347 HP)	**Control Method:** None **NOx Emission Limit:** 4.0 g/kW-hr NMHC+NOx *(converts to 2.94 g/hp-hr and 2.25 lb/hr)*
WPL - Riverside Energy Center	19-DMM-153 (02/28/2020)	LA-0370	Diesel-Fired Fire Pump Engine (290 HP)	**Control Method:** Only use diesel fuel oil with a sulfur content of no greater than 0.0015% by weight **NOx Emission Limit:** 3.64 lb/hr *(converts to 7.74 g/kW-hr or 5.69 g/hp-hr)*

Maple Creek Energy I LLC proposes the use of state-of-the-art combustion design and an emission limit of 4.0 g/kW-hr for NMHC+NOx combined as BACT for NOx. No add-on controls were seen in the review of other similar BACT determinations. Additionally, based on conservatively low-cost estimates, no add-on controls are considered to be economically feasible for controlling NOx emissions from the emergency fire water pump. Therefore, the Permittee has proposed the best control/reduction methods.

The emission limits seen in the review of other determinations were based on compliance with the combined NMHC+NOx emission limit in 40 CFR 60, Subpart IIII for fire pump engines

No additional controls are considered to be technically or economically feasible for controlling NOx emissions from the emergency fire water pump engine. Therefore, the proposed BACT limit will be considered as the top BACT for this unit and no further evaluation of this operation is required and an economic, energy, or environmental impact analysis is not required as part of the NOx BACT evaluation for this unit.

Step 5: Select BACT (NOx)

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (BACT) for NOx for the diesel-fired emergency fire water pump (FP) engine shall be as follows:

(a) NMHC+NOx emissions from the diesel-fired emergency fire water pump engine (FP) combined shall not exceed 4.0 g/kW-hr.

(b) NMHC+NOx emissions from the diesel-fired emergency fire water pump engine (FP) combined shall not exceed 2.72 lb/hr.

(c) NOx emissions shall be reduced through the implementation of state-of-the-art combustion design and good combustion practices.

CO BACT Determination: Diesel-Fired Emergency Fire Pump Engine

Step 1: Identify Potential Control Technologies (CO)

Carbon monoxide (CO) emissions are formed during combustion processes because of incomplete combustion of carbon in the fuel. This occurs if there is a lack of available oxygen near the fuel molecule during combustion, if the gas temperature is too low, or if the residence time is too short.

Decreases in CO emissions are generally seen through proper engine maintenance and good combustion practices. Add-on controls for CO emissions from internal combustion engines include nonselective catalytic reduction, diesel oxidation catalysts, diesel particulate filters, and lean NOx catalysts. These are discussed below:

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 CO2. CO is oxidized to CO2 and hydrocarbons are oxidized to CO2 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.

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. CO emissions can be reduced by 70-99%.

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. CO emissions can be reduced by 90%.

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 Catalysts are also capable of reducing CO emissions by around 60%.

Combustion Design Controls
CO emissions are caused by 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 CO and unburned hydrocarbons that exit with the exhaust. CO formation can be minimized by improving the fuel air mixing through enhanced fuel injection systems, air management systems, combustion system designs, and pre-mixed diesel combustion.

Step 2: Eliminate Technically Infeasible Options (CO)

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 water pump engine. No other control options are being eliminated due to technical infeasibility.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness (CO)

Control/Method	***% Reduction***
Diesel Oxidation Catalyst	70-99%
Diesel Particulate Filter	90%
Lean NOx Catalyst	60%
Good Combustion Practices	Varies

Step 4: Evaluate the Most Effective Controls and Document the Results (CO)

The following table summarizes other BACT determinations for emergency diesel-fired fire pump engines that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) under Process Type Code 17.210 (Small Internal Combustion Engines <500 HP - Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel)), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date. Only fire pump engines and water pumps are included in this table; emergency generators were excluded from this evaluation.

Summary of RBLC Database Review - Small Internal Combustion Engines - Diesel Fuel

Facility	**Permit Number & Date**	**RBLC ID #**	**Emission Unit**	**CO Emission Limits**
Maple Creek Energy I LLC	Proposed	--	Diesel-fired Emergency Fire Pump Engine (420 HP)	**Control Method:** State-of-the-art combustion design and good combustion practices **CO Emission Limit:** 3.5 g/kW-hr *(converts to 2.57 g/hp-hr)* 2.38 lb/hr
Maple Creek Energy I LLC	T153-45909-00056 (06/19/2023)	IN-0365	Diesel Emergency Fire Pump (420 bHP)	**Control Method:** None **CO Emission Limit:** 3.50 g/kW-hr *(converts to 2.57 g/hp-hr and 2.61 lb/hr)*
Maple Creek Energy II LLC	Proposed	--	Diesel-fired Emergency Fire Pump Engine (420 HP)	**Control Method:** State-of-the-art combustion design and good combustion practices **CO Emission Limit:** 3.5 g/kW-hr *(converts to 2.57 g/hp-hr)* 2.38 lb/hr
Hybar	2470-AOP-R2 (10/02/2025)	AR-0191	Diesel Emergency Water Pumps (376 HP, each)	**Control Method:** Good operating practices, limited hours of operation **CO Emission Limit:** 3.03 g/hp-hr *(converts to 4.12 g/kW-hr and 2.51 lb/hr)*
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	ULSD Emergency Fire Water Pump (282 bhp)	**Control Method:** Good operating practices, low sulfur fuel **CO Emission Limit:** 2.6 g/hp-hr *(converts to 3.54 g/kW-hr)* 1.62 lb/hr
Duke Energy Indiana, Inc. - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	Diesel Emergency Fire Pump (300 HP)	**Control Method:** Good operating practices **No CO Emission Limit**
Shintech Plaquemine Plant 4	PSD-LA-857 (12/16/2024)	LA-0403	Three (3) Diesel Emergency Fire Pumps (200 HP, each)	**Control Method:** None **CO Emission Limit:** 1.15 lb/hr 3.50 g/hp-hr *(converts to 4.76 g/kW-hr)*
Lansing Board of Water and Light- Delta Energy Park	71-24 (06/27/2024)	MI-0459	Diesel Fire Pump (500 bHP)	**Control Method:** Good combustion practices **CO Emission Limit:**

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO Emission Limits
				3.50 g/kW-hr *(converts to 2.57 g/hp-hr and 2.83 lb/hr)*
Cronus Chemicals, LLC	19110020 (12/21/2023)	IL-0134	Firewater Pump Engine (369 HP)	**Control Method:** None **CO Emission Limit:** 3.50 g/kW-hr *(converts to 2.57 g/hp-hr and 2.09 lb/hr)* 100 hours/year
Koch Methanol (KME) Facility	PSD-LA-851 (12/20/2023)	LA-0401	Firewater Pump Engines No. 1 and 2 (422 HP, each)	**Control Method:** None **CO Emission Limit:** 3.44 lb/hr *(converts to 5.0 g/kW-hr or 3.7 g/hp-hr)*
			Firewater Pump Engine No. 3 (237 HP)	**Control Method:** None **CO Emission Limit:** 0.50 lb/hr *(converts to 1.3 g/kW-hr or 0.96 g/hp-hr)*
Shell Chemical LP Geismar Plant	PSD-LA-647(M-9) (12/12/2023)	LA-0394	Two (2) Diesel Sump Pump Drivers (200 HP, each)	**Control Method:** Good combustion practices **CO Emission Limit:** 1.14 lb/hr hourly maximum 3.50 g/kW-hr *(converts to 2.57 g/hp-hr)*
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Emergency Diesel Fire Pump (282 HP)	**Control Method:** Good combustion practices **CO Emission Limit:** 2.60 g/hp-hr *(converts to 3.54 g/kW-hr)* 500 hours/year (rolling)
Kronospan, LLC	301-0079 (09/21/2022)	AL-0337	Diesel Fire Pump (460 bHP)	**Control Method:** Catalyst, 500 hr/yr operational limit **CO Emission Limit:** 2.60 g/hp-hr *(converts to 3.5 g/kW-hr)* 2.64 lb/hr
Intel Ohio Site	P0132323 (09/20/2022)	OH-0387	Diesel-Fired Emergency Fire Pump Engine (275 HP)	**Control Method:** Good combustion practices **CO Emission Limit:** 3.50 g/kW-hr *(converts to 2.57 g/hp-hr)* 1.80 lb/hr 0.5 tons/year (rolling)
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	ULSD Fire Water Pump Engine (320 HP)	**Control Method:** None **CO Emission Limit:** 3.50 g/kW-hr *(converts to 2.57 g/hp-hr and 1.81 lb/hr)*
Alaska Gasline Development Corporation Liquefaction Plant	AQ1539CPT01 (07/07/2022)	AK-0088	Diesel Fire Pump Engine (575 HP)	**Control Method:** Oxidation catalyst, limited operation **CO Emission Limit:** 3.30 g/hp-hr *(converts to 4.49 g/kW-hr and 4.18 lb/hr)* 500 hours/year

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO Emission Limits
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Diesel-Fired Emergency Fire Pump Engine (300 HP)	**Control Method:** Good combustion practices **CO Emission Limit:** 2.60 g/hp-hr *(converts to 3.54 g/kW-hr and 1.72 lb/hr)*
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/23/2022)	MI-0452	Diesel-Fired Emergency Fire Pump Engine (300 HP)	**Control Method:** Good combustion practices **CO Emission Limit:** 2.60 g/hp-hr *(converts to 3.54 g/kW-hr and 1.72 lb/hr)*
Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Emergency Diesel Fired Water Pump Engine (355 HP)	**Control Method:** Good combustion practices and use of ultra-low sulfur diesel fuel **CO Emission Limit:** 2.60 g/hp-hr *(converts to 3.54 g/kW-hr and 2.03 lb/hr)*
Big River Steel LLC	2445-AOP-R0 (01/31/2022)	AR-0173	Emergency Water Pumps	**Control Method:** Good operating practices and limited hours of operation **CO Emission Limit:** 3.03 g/hp-hr *(converts to 4.12 g/kW-hr)*
Mountain State Clean Energy, LLC Maidsville	R14-0038 (01/05/2022)	WV-0033	ULSD Fire Water Pump (240 bHP)	**Control Method:** Good combustion practices with oxidation catalyst **CO Emission Limit:** 1.38 lb/hr 0.60 g/bkW-hr *(converts to 0.44 g/hp-hr)* 2.60 g/bkW-hr *(converts to 1.91 g/hp-hr)*
Shady Hills Energy Center, LLC	1010524-003-AC (PSD-FL-444A) (06/07/2021)	FL-0371	Diesel Emergency Fire Pump (347 HP)	**Control Method:** None **CO Emission Limit:** 3.5 g/kW-hr *(converts to 2.57 g/hp-hr and 1.97 lb/hr)*
WPL - Riverside Energy Center	19-DMM-153 (02/28/2020)	LA-0370	Diesel-Fired Fire Pump Engine (290 HP)	**Control Method:** Good combustion practices **CO Emission Limit:** 0.33 lb/hr *(converts to 0.70 g/kW-hr or 0.52 g/hp-hr)*

Maple Creek Energy I LLC proposes the use of state-of-the-art combustion design and an emission limit of 3.5 g/kW-hr (converted to 2.6 g/hp-hr) as BACT for CO. No add-on controls were seen in the review of other similar BACT determinations. Additionally, based on conservatively low-cost estimates, no add-on controls are considered to be economically feasible for controlling CO emissions from the emergency fire water pump. Therefore, the Permittee has proposed the best control/reduction methods.

The majority of the emission limits seen in the review of other determinations were based on compliance with the CO emission limit in 40 CFR 60, Subpart IIII for fire pump engines.

The proposed BACT limit will be considered as the top BACT for this unit. No further evaluation of this operation is required and an economic, energy, or environmental impact analysis is not required as part of the CO BACT evaluation for this unit.

Step 5: Select BACT (CO)

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (BACT) for CO for the diesel-fired emergency fire water pump engine (FP) shall be as follows:

(a) CO emissions from the diesel-fired emergency fire water pump engine (FP) shall not exceed 3.5 g/kW-hr.

(b) CO emissions from the diesel-fired emergency fire water pump engine (FP) shall not exceed 2.38 lb/hr.

(c) CO emissions shall be reduced through the implementation of state-of-the-art combustion design and good combustion practices.

SO_2/H_2SO_4 BACT Determination: Diesel-Fired Emergency Fire Pump Engine

Step 1: Identify Potential Control Technologies (SO_2)

Sulfur dioxide emissions produced by internal combustion engines result from the oxidation of sulfur in the fuel rather than from combustion variables. Therefore, the sulfur content of the fuel is the biggest factor for SO_2 emissions. No add-on controls are typically used to control SO_2 emissions from these types of engines and will not be considered in this review.

Fuel Choice and Usage Limitations
Most of the sulfur present in fuel is oxidized to SO_2. Therefore, choosing a fuel with a lower sulfur content will result in lower SO_2 emissions. The emergency fire water pump engine is an existing unit and is a diesel engine. Therefore, no other types of fuel, such as natural gas, will be considered. However, these types of engines can run on low sulfur diesel fuel (0.05% sulfur) and ultra-low sulfur diesel fuel (0.0015% sulfur), which provide for lower SO_2 emissions. Additionally, restrictions on the amount of fuel or hours of operation can further limit all emissions.

Step 2: Eliminate Technically Infeasible Options (SO_2)

The only control option for the emergency fire water pump engine is fuel choice and usage limitations.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness (SO_2)

Control/Method	***% Reduction***
Sulfur Content of Fuel / Fuel Use Limitations	Varies

Step 4: Evaluate the Most Effective Controls and Document the Results (SO_2)

The following table summarizes other BACT determinations for emergency diesel-fired fire pump engines that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) under Process Type Code 17.210 (Small Internal Combustion Engines <500 HP - Fuel Oil (ASTM #1, 2, includes kerosene, aviation, diesel fuel)), as well as IDEM, OAQ permits issued to date. The BACT determinations are arranged in descending order in terms of issuance date. Only fire pump engines and water pumps are included in this table; emergency generators were excluded from this evaluation.

Summary of RBLC Database Review - Small Internal Combustion Engines - Diesel Fuel

Facility	Permit Number & Date	RBLC ID #	Emission Unit	SO_2/H_2SO_4 Emission Limits
Maple Creek Energy I LLC	Proposed	--	Diesel-fired Emergency Fire Pump Engine (420 HP)	**Control Method:** Only use ultra-low sulfur diesel fuel (ULSD)(0.0015% S) **SO_2 Emission Limit:** 0.0016 lb/MMBtu **H_2SO_4 Emission Limit:** 0.0002 lb/MMBtu
Hybar	2470-AOP-R2 (10/02/2025)	AR-0191	Diesel Emergency Water Pumps (376 HP, each)	**Control Method:** Good operating practices, limited hours of operation **SO_2 Emission Limit:** 15.00 ppm or less S in fuel *(converts to 0.02 lb/MMBtu)*
Nemadji Trail Energy Center	21-JAM-212 (09/19/2023)	WI-0326	Emergency Diesel Fire Pump (282 HP)	**Control Method:** Good operating practices, limited hours of operation, unit shall be operated and maintained according to the manufacturer's recommendations, sulfur content of diesel fuel oil fired may not exceed 15 ppm *(converts to 0.02 lb/MMBtu)* **SO_2 Emission Limit:** 500 hours/year (rolling)
Maple Creek Energy LLC	T153-45909-00056 (06/19/2023)	IN-0365	Diesel Emergency Fire Pump (420 bHP)	**Control Method:** The sulfur content of diesel fuel burned in the emergency fire pump shall not exceed 0.0015%. **SO_2 Emission Limit:** 0.0016 lb/MMBtu **H_2SO_4 Emission Limit:** 0.0002 lb/MMBtu
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	ULSD Fire Water Pump Engine (320 HP)	**Control Method:** Use of ultra-low sulfur diesel, with a sulfur content of less than 15 ppm sulfur **No SO_2 Emission Limit** **No H_2SO_4 Emission Limit**
Alaska Gasline Development Corporation Liquefaction Plant	AQ1539CPT01 (07/07/2022)	AK-0088	Diesel Fire Pump Engine (575 HP)	**Control Method:** Good combustion practices, limited operation **SO_2 Emission Limit:** 15.0 ppmw sulfur in fuel *(converts to 0.02 lb/MMBtu)* 500 hours/year
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Diesel-Fired Emergency Fire Pump Engine (300 HP)	**Control Method:** Good combustion practices **SO_2 Emission Limit:** 15.0 ppm fuel supplier records or sample test *(converts to 0.02 lb/MMBtu)*
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/23/2022)	MI-0452	Diesel-Fired Emergency Fire Pump Engine (300 HP)	**Control Method:** Good combustion practices **SO_2 Emission Limit:** 15.0 ppm fuel supplier records or sample test *(converts to 0.02 lb/MMBtu)*
Big River Steel LLC	2445-AOP-R0 (01/31/2022)	AR-0173	Emergency Water Pumps	**Control Method:** Good operating practices and limited hours of operation **SO_2 Emission Limit:** 15 ppm sulfur in fuel *(converts to 0.02 lb/MMBtu)*
Shady Hills Energy Center, LLC	1010524-003-AC (PSD-FL-444A) (06/07/2021)	FL-0371	Diesel Emergency Fire Pump (347 HP)	**Control Method:** None **SO_2 Emission Limit:** 15 ppm sulfur in fuel *(converts to 0.02*

Facility	Permit Number & Date	RBLC ID #	Emission Unit	SO_2/H_2SO_4 Emission Limits
				lb/MMBtu)
WPL - Riverside Energy Center	19-DMM-153 (02/28/2020)	LA-0370	Diesel-Fired Fire Pump Engine (290 HP)	**Control Method:** Only use diesel fuel oil with sulfur content of no greater than 0.0015% by weight **SO_2 Emission Limit:** 0.36 lb/hr *(converts to 0.002 lb/MMBtu or 15.0 ppm)* **No H_2SO_4 Emission Limit**

Maple Creek Energy I LLC proposes the use of ultra-low sulfur diesel fuel with a maximum of 0.0015% sulfur content and a SO_2 emission rate of less than 0.0016 lb/MMBtu as BACT for SO_2. No add-on controls were seen in the review of other similar BACT determinations. Most BACT determinations for SO_2 involve limiting the sulfur content of the fuel based on the requirements of 40 CFR 60, Subpart IIII. Additionally, some determinations include pound per hour and/or ton per year limits or other limitations on usage or hours of operation.

The proposed BACT meets the most stringent BACT; therefore, no further evaluation of this operation is required and an economic, energy, or environmental impact analysis is not required as part of the SO_2 BACT evaluation for this unit.

Step 5: Select BACT (SO_2)

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (BACT) for SO_2 for the diesel-fired emergency fire pump engine (FP) shall be as follows:

(a) Only ultra-low sulfur diesel (ULSD) (0.0015% S) shall be used in the diesel-fired emergency fire pump engine (FP).

GHG BACT Determination: Diesel-Fired Emergency Fire Pump Engine

Step 1: Identify Potential Control Technologies (CO_{2e})

CO_2 is by far the dominant GHG from this source. CH_4 and N_2O are present only in very small amounts, are incidental to combustion, and trend with the CO_2 emissions. There are no known supplemental controls for N_2O or methane emissions from diesel engines. To the extent measures are identified that reduce CO_2, the other GHGs may be also reduced accordingly. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

Diesel fuel is used because it is an independent source of fuel not related to the operation of the facility. As such, it is the most reliable fuel source and its use in this application is fundamental to meeting power and water requirements in an emergency situation. For this reason, it is the most common fuel used for these types of emergency backup applications.

GHG control possibilities identified and addressed in this BACT analysis for these small engines are:

(1) Good engineering design and Fuel-efficient design; and

(2) Post combustion carbon capture

Step 2: Eliminate Technically Infeasible Options (CO_{2e})

Good Engineering Design and Fuel-Efficient Design
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. This emergency diesel fire pump engine is built with automatic control of the air to fuel ratio that ensures that it operates when needed and meets 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 generators at this source.

Carbon Capture
Post-combustion CO_2 capture is a relatively new concept. In EPA's recent GHG BACT guidance, EPA takes the position that, "*for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams".* The source combustion sources such as the emergency engines do not fit into either of the above categories called out by EPA's guidance document as appropriate for consideration of CCS. The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above examples. However, relevant guidance can be discerned from the Appendix F to the above referenced US EPA guidance document, which presents an example GHG BACT analysis for a 250 MMBtu/hr natural gas fired boiler. In this US EPA boiler example, carbon capture isn't listed or considered in the BACT analysis as a potentially available option. The absence of a discussion of carbon capture in this 250 MMBtu/hr boiler example is consistent with the fact that carbon capture is extremely expensive, has numerous technical challenges, and is currently only being contemplated on very large or very concentrated CO_2 sources. In stark contrast, the source's Project miscellaneous combustion sources are an order of magnitude smaller than EPA's example, and significantly smaller still than the categories that US EPA's guidance document suggests should consider CCS.

A CO_2 capture system for the emergency diesel engines is not a reasonable BACT option because the capture of CO_2 from combustion exhaust of small sources is significantly more difficult than from the types of industrial gas streams that EPA references as having potential for CCS. The increased difficulty is due to four factors: low CO_2 concentration, low pressure, low quantity of CO_2 available for capture, and the variability of load for these units.

The low concentration and low pressure of the exhausts from these processes complicate the absorption and desorption of the CO_2, which increases the energy required. Also, a low-pressure absorption system creates a low-pressure CO_2 stream which requires a very high energy demand for compression prior to transport. All these factors make the application of CO_2 capture on any small combustion exhaust extremely difficult and expensive. Additionally, the cost of capturing CO_2 for smaller sources is more expensive due to the lack of economy-of-scale. Further, the emergency engines are intermittent sources, which would further increase the cost and difficulty of implementing any control.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of post-combustion capture of CO_2 is not a technically feasible option for the emergency generators at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness (CO_{2e})

The only feasible, applicable and available control technology identified to reduce greenhouse gases from the emergency diesel fire pump engines is to utilize good engineering design and fuel-efficient design.

Step 4: Evaluate the Most Effective Controls and Document the Results (CO_{2e})

The table below shows the proposed CO_{2e} 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.

Summary of RBLC Database Review - Small Internal Combustion Engines - Diesel Fuel

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO_{2e} Emission Limits
Maple Creek Energy I LLC	Proposed	--	Diesel-fired Emergency Fire Pump Engine (420 HP)	**Control Method:** Good engineering design and fuel-efficient design **CO_{2e} Emission Limit:** 24 tons/year
Maple Creek Energy I LLC	Existing T153-45909-00056 (06/19/2023)	IN-0365	Diesel Emergency Fire Pump (420 bhp)	**Control Method:** Good engineering design and fuel-efficient design **CO_{2e} Emission Limit:** 123 tons/year
Maple Creek Energy II LLC	Proposed	--	Diesel-fired Emergency Fire Pump Engine (420 HP)	**Control Method:** Good engineering design and fuel-efficient design **CO_{2e} Emission Limit:** 24 tons/year
Hybar	2470-AOP-R2 (10/02/2025)	AR-0191	Diesel Emergency Water Pumps (376 HP, each)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 164 lb/MMBtu
Sycamore Riverside Energy LLC	153-47292-00062 (03/31/2025)	IN-0384	ULSD Emergency Fire Water Pump (282 bhp)	**Control Method:** Good engineering design, fuel efficient design, limited operating hours **CO_{2e} Emission Limit:** 1,115,606 tons/year (rolling)
Duke Energy Indiana, Inc. - Cayuga Generating Station	165-47430-00001 (02/14/2025)	IN-0382	Diesel Emergency Fire Pump (300 HP)	**Control Method:** Good combustion practices **No CO_{2e} Emission Limit**
Lansing Board of Water and Light- Delta Energy Park	71-24 (06/27/2024)	MI-0459	Diesel Fire Pump (500 bhp)	**Control Method:** Good combustion practices, use of current energy efficiency measures **CO_{2e} Emission Limit:** 27 tons/year (rolling)
Cronus Chemicals, LLC	19110020 (12/21/2023)	IL-0134	Firewater Pump Engine (369 HP)	**Control Method:** None **CO_{2e} Emission Limit:** 25 tons/year 100 hours/year operational limit
Bunge Chevron AG Renewables, LLC / Destrehan Oil Processing Facility	PSD-LA-855 (12/13/2023)	LA-0402	Emergency Diesel Fire Pump Engine (200 HP)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 12 tons/year (rolling)
Shell Chemical LP Geismar Plant	PSD-LA-647(M-9) (12/12/2023)	LA-0394	Two (2) Diesel Sump Pump Drivers (200 HP, each)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 12 tons/year (rolling)
Nemadji Trail Energy	21-JAM-212	WI-0326	Emergency Diesel Fire	**Control Method:**

Facility	Permit Number & Date	RBLC ID #	Emission Unit	CO_{2e} Emission Limits
Center	(09/19/2023)		Pump (282 HP)	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). **CO_{2e} Emission Limit:** 500 hours/year (rolling)
Intel Ohio Site	P0132323 (09/20/2022)	OH-0387	Diesel-Fired Emergency Fire Pump Engine (275 HP)	**Control Method:** Good combustion practices and proper maintenance and operation **CO_{2e} Emission Limit:** 162.70 lb/MMBtu
Lincoln Land Energy Center (A/K/A Emberclear) Lincoln Land Energy Center	18040008 (07/29/2022)	IL-0133	ULSD Fire Water Pump Engine (320 HP)	**Control Method:** None **CO_{2e} Emission Limit:** 92 tons/year
Alaska Gasline Development Corporation Liquefaction Plant	AQ1539CPT01 (07/07/2022)	AK-0088	Diesel Fire Pump Engine (575 HP)	**Control Method:** Good combustion practices, limited operation **CO_{2e} Emission Limit:** 163.60 lb/MMBtu 500 hours/year
Marshall Energy Center, LLC - MEC North, LLC	167-17B (06/23/2022)	MI-0451	Diesel-Fired Emergency Fire Pump Engine (300 HP)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 85.6 tons/year (rolling)
Marshall Energy Center, LLC - MEC South, LLC	168-17B (06/23/2022)	MI-0452	Diesel-Fired Emergency Fire Pump Engine (300 HP)	**Control Method:** Good combustion practices **CO_{2e} Emission Limit:** 85.6 tons/year (rolling)
Magnolia Power Generating Station Unit 1	PSD-LA-839 (06/03/2022)	LA-0391	Emergency Diesel Fired Water Pump Engine (355 HP)	**Control Method:** Good combustion practices and use of ultra-low sulfur diesel fuel **CO_{2e} Emission Limit:** 74.21 kg/MMBtu
Big River Steel LLC	2445-AOP-R0 (01/31/2022)	AR-0173	Emergency Water Pumps	**Control Method:** Good operating practices **CO_{2e} Emission Limit:** 164 lb/MMBtu

Based on the information from the table above, most emergency fire pump engines have only an annual tons per year limit specified that is based upon the engine rating and operating hour restrictions.

The proposed BACT meets the most stringent BACT; therefore, no further evaluation of this operation is required and an economic, energy, or environmental impact analysis is not required as part of the CO_{2e} BACT evaluation for this unit.

Step 5: Select BACT (CO_{2e})

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (BACT) for CO_{2e} for the diesel-fired emergency fire water pump engine (FP) shall be as follows:

(a) The use of a good engineering design and fuel-efficient design; and

(b) CO_{2e} emissions from the diesel-fired emergency fire pump (FP) shall not exceed 24 tons per year.

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

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Nicholas Zaborowsky
Maple Creek Energy LLC
155 Federal St 17th Fl
Boston, MA 021101972

DATE: May 13, 2026

FROM: Jenny Acker, Branch Chief
Permits Branch
Office of Air Quality

SUBJECT: Final Decision
TV Significant Source Modification (Major PSD/EO)
153-49550-00056

This notice is to inform you that a final decision has been issued for the air permit application referenced above.

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. In addition, the Notice of Decision has been sent to the OAQ Permits Branch Interested Parties List and, if applicable, the Consultant/Agent and/or Responsible Official/Authorized Individual.

The original signature page is enclosed for your convenience. The final decision and supporting materials 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 49550

and

IDEM's Virtual File Cabinet (VFC): A copy of the issued permit is also available via IDEM's Virtual File Cabinet (VFC) located at https://www.in.gov/idem/legal/public-records/virtual-file-cabinet/. Click on the Virtual File Cabinet button. Click on the "Search" dropdown menu in the upper left corner and select "OAQ Permit" from the list of options. Select "Public" in the "Security group" dropdown menu. Type the five-digit permit number 49550 in the Permit # search field, select "Final" in the "Permit Type" dropdown menu, then click the search button at the top or bottom of the webpage. The search will return the final issued permit and any applicable mailing list.

If you have requested to receive a hard copy of these documents, the final decision and supporting documents for the air permit application referenced above are enclosed. If applicable, this packet contains the original, signed, permit documents.

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit. If you think you have received this document in error, or have difficulty accessing the documents online, please contact Joanne Smiddie-Brush of my staff at 1-800-451-6027 (ext 3-0185), or via e-mail at jbrush@idem.IN.gov.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

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(800) 451-6027 • (317) 232-8603 • Fax (317) 233-6647 • www.idem.IN.gov

Mike Braun
Governor

Clint Woods
Commissioner

May 13, 2026

TO: Sullivan County Public Library - Shelburn Public Library

From: Jenny Acker, Branch Chief
Permits Branch
Office of Air Quality

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: Maple Creek Energy LLC
Permit Number: 153-49550-00056

You previously received information to make available to the public during the public comment period of a draft permit. Enclosed is a copy of the final decision and supporting materials for the same project. Please place the enclosed information along with the information you previously received. To ensure that your patrons have ample opportunity to review the enclosed permit, **we ask that you retain this document for at least 60 days.**

The applicant is responsible for placing a copy of the application in your library. If the permit application is not on file, or if you have any questions concerning this public review process, please contact Joanne Smiddie-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185.

Enclosures
Final Library 1/13/2025

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

May 13, 2026
Maple Creek Energy LLC
153-49550-00056

To: Interested Parties

This notice is to inform you that a final decision has been issued for the air permit application referenced above. This notice is for informational purposes only. You are not required to take any action.

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 enclosed Notice of Decision Letter provides additional information about the final permit decision.

The final decision is available on the IDEM website at: https://www.in.gov/apps/idem/caats/. To view the document, choose Search Option by **Permit Number**, then enter permit 49550

The final decision is also available via IDEM's Virtual File Cabinet (VFC) located at https://www.in.gov/idem/legal/public-records/virtual-file-cabinet/. Click on the Virtual File Cabinet button. Click on the "Search" dropdown menu in the upper left corner and select "OAQ Permit" from the list of options. Select "Public" in the "Security group" dropdown menu. Type the five-digit permit number 49550 in the Permit # search field, select "Final" in the "Permit Type" dropdown menu, then click the search button at the top or bottom of the webpage. The search will return the final issued permit and any applicable mailing list.

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit.

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
Final Interested Parties Cover Letter

Mail Code 61-53

IDEM Staff	JLSCOTT 5/13/2026 Page 1 of 2 Maple Creek Energy LLC 153-49550-00056 Final			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
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2		Marc Duquette Director of Environmental Services Maple Creek Energy LLC 155 Federal St 17th Fl Boston MA 021101972 *(RO CAATS)*									
3		Sullivan City Council and Mayors Office 110 N Main St Sullivan IN 47882 *(Local Official)*									
4		Sullivan County Health Department 27 S Main St Sullivan IN 47882-1516 *(Health Department)*									
5		Sullivan County Commissioners 100 Courthouse Square, Ste 100 Sullivan IN 47882-1593 *(Local Official)*									
6		Mr. Richard Monday S & G Excavating 545 E Margaret Dr Terre Haute IN 47802 *(Affected Party)*									
7		Indiana Michigan Power Company PO Box 16428 Columbus OH 43216 *(Affected Party)*									
8		Gary & Susan Holmes 168 E CR 110 N Farmersburg IN 47850-8205 *(Affected Party)*									
9		Sullivan County Public Library - Shelburn Branch 17 W Griffith St Shelburn IN 47879 *(Library)*									
10		Mr. Mark Fitton Tribune-Star 2800 Poplar St, Ste 37A Terre Haute IN 47807 *(Affected Party)*									
11		James R Crowell Or Current Resident 10040 North Country Road 675 W Fairbanks IN 47849-8072 *(Affected Party)*									
12		Drake Family Farms Inc 5572 West Country Road 1075 N Farmersburg IN 47850-8236 *(Affected Party)*									
13		Scott Harris Or Current Resident 10983 North SR 63 Farmersburg IN 47850-8225 (Affected Party)									
14		Everett F III Long 9715 N SR 63 Farmersburg IN 47850-8226 *(Affected Party)*									
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1		Steven, Robert & Verneal 9571 N SR 63 Farmersburg IN 47850-8223 (Affected Party)									
2		Kenneth OVivion 9483 North SR 63 Farmersburg IN 47850-8223 *(Affected Party)*									
3		Earl T & Carol J Kirk PO Box 204 Fairbanks IN 47849-0204 *(Affected Party)*									
4		Judith Ann & Raymond Edward Arnett PO Box 15 Fairbanks IN 47849-0015 *(Affected Party)*									
5		Danny V & Nancy L Woodard 6454 West Market St Fairbanks IN 47849-8062 *(Affected Party)*									
6		Lynn Gresock Haley & Aldrich Inc 3 Bedford Farms Rd Ste 301 Bedford NH 03110 *(Consultant)*									
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