INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
Toll Free (800) 451-6027
www.idem.IN.gov

TO: Interested Parties / Applicant

DATE: December 3, 2012

RE: St. Joseph Energy Center, LLC / 141-31003-00579

FROM: Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

Notice of Decision: Approval – Effective Immediately

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the enclosed matter. Pursuant to IC 13-15-5-3, this permit is effective immediately, unless a petition for stay of effectiveness is filed and granted, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

If you wish to challenge this decision, IC 4-21.5-3-7 and IC 13-15-6-1(b) or IC 13-15-6-1(a) require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office of Environmental Adjudication, 100 North Senate Avenue, Government Center North, Suite N 501E, Indianapolis, IN 46204.

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

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

The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

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

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

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

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

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

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

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

Enclosures
FNTVOP.dot12/3/07

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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Mr. Willard Ladd
St. Joseph Energy Center, LLC
c/o Development Partners Group
11 Martine Avenue, Fl.9
White Plains, NY 10606

December 3, 2012

PSD/New Source Construction/Part 70
Operating Permit No.: T 141-31003-00579

Dear Mr. Ladd:

St. Joseph Energy Center, LLC located at the Corner of Walnut and Edison Roads, New Carlisle, Indiana, in St. Joseph County submitted a PSD and Title V Operating Permit application to IDEM, OAQ on October 3, 2011, relating to the proposed construction and operation of a combined cycle combustion turbine (CCCT) electric generating facility (CCCT Facility). The proposed CCCT Facility will consist of a nominal net 1,350 MW natural gas-fired CCCT operation that includes two natural gas-fired 2x1 CCCT blocks and ancillary equipment Pursuant to 326 IAC 2-2 and 326 IAC 2-7 the following emission units are approved for construction at the source:

(a) Four (4) natural gas-fired combined cycle combustion turbines, identified as units CCCT1, CCCT2, CCCT3, and CCCT4, permitted in 2012, each with a combustion turbine equipped with dry low NOx burners, natural gas fired duct burners, and a heat recovery steam generator identified as HRSG1, HRSG2, HRSG3, and HRSG4, NOx emissions controlled by four (4) selective catalytic reduction (SCR) systems (SCR01, SCR02, SCR03 and SCR04), CO and VOC emissions controlled by oxidation catalyst systems (CAT01, CAT02, CAT03 and CAT04) and exhausting to stacks CCCT01, CCCT02, CCCT03, and CCCT04, respectively. Each stack has continuous emissions monitors (CEMS) for NOx and CO. The nominal heat input for each CCCT is 2,300 MMBtu/hr (higher heating value (HHV)). The combined nominal power output is 1,350 megawatts (MW).

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

(b) Two (2) natural gas fired auxiliary boilers, identified as B001 and B002, permitted in 2012, each, with a maximum heat input capacity of 80 MMBtu/hr (HHV), equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stacks B001 and B002. Under 40 CFR Part 60, Subpart Dc, the auxiliary boiler is considered a steam generating unit.

(c) One (1) emergency diesel generator, nominally rated at 2012 horsepower, identified as EG03, permitted in 2012, exhausting through one (1) vent, identified as EG03. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generator is considered a new affected source

Insignificant and Trivial Activities

The source also consists of the following insignificant activities as defined in 326 IAC 2-7-1(21):

(a) Two (2) firewater pump engines, each nominally rated at 371 brake horsepower (bph) and identified as FP01 and FP02, permitted in 2012, exhausting through two (2) vents, identified as FP01 and FP02, respectively. [Under 40 CFR 60, Subpart IIII, the firewater pump engines are considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the firewater pump engines are considered new affected sources.]

(b) Two (2) emergency diesel generators, each nominally rated at 1,006 horsepower, identified as EG01 and EG02, permitted in 2012, exhausting through two (2) vents, identified as EG01 and EG02, respectively. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generators are considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generators are considered new affected source.]

(c) Two (2) cooling towers, each nominally rated with a circulation rate of 170,000 gpm , identified as CT01 and CT02, permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through ten vents each, identified as CT01A – CT01J and CT02A – CT02J.

(d) Six (6) Turbine Lube Demister Vents, identified as DM01 - DM06, permitted in 2012, exhausting through vents DM01 – DM06.

(e) Six (6) Turbine Lube Oil storage tanks, identified as TK01 - TK06, permitted in 2012, each with a nominal capacity of 6,800 gallons.

(f) Two (2) Emergency Generator ULSD Tanks, identified as TK07 and TK08, permitted in 2012, each with a nominal capacity of 550 gallons.

(g) Two (2) Fire Pump Engine ULSD Tanks, identified as TK09 and TK10, permitted in 2012, each with a nominal capacity of 70 gallons.

(h) One (1) Vehicle Gasoline Tank, identified as TK11, permitted in 2012, with a nominal capacity of 650 gallons, equipped with submerged fill and stage 1 vapor balance.

(i) One (1) Vehicle Diesel Tank, identified as TK12, permitted in 2012, with a nominal capacity of 650 gallons.

(j) One (1) Emergency Generator ULSD Tank, identified as TK50, permitted in 2012, with a nominal capacity of 300 gallons.

(k) two (2) lime storage silos, capable of handling a maximum loading rate of 20 tons per hour combined, permitted in 2012 and with particulate matter controlled by bin vent filters exhausting to Stacks S1 and S2;

(l) Six (6) Electrical Circuit Breakers containing sulfur hexafluoride (SF_6) identified as emissions unit SF6, permitted in 2012, with fugitive GHG emissions.

(m) Space heaters, process heaters, or boilers using the following fuels: Natural gas-fired combustion sources with heat input equal to or less than ten million (10,000,000) Btu per hour.

(n) The following VOC and HAP storage containers: Vessels storing lubricating oils, hydraulic oils, and machining oils.

(o) Application of the following as temporary protective coatings: greases, lubricants, nonvolatile materials, and oils.

(p) Degreasing operations that do not exceed one hundred forty-five (145) gallons per 12 months, except if subject to 326 IAC 20-6. [326 IAC 8-3];

(q) Cleaners and solvents characterized as follows where the use of which, for all cleaners and solvents combined, does not exceed one hundred forty-five (145) gallons per 12 months:

(1) Having a vapor pressure equal to or less than 2 kPa; 15 mm Hg; or 0.3 psi measured at 38 degrees C (100°F) or;

(2) Having a vapor pressure equal to or less than 0.7 kPa; 5 mm Hg; or 0.1 psi measured at 20°C (68°F);

(r) Closed loop heating and cooling systems.

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

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

(u) Heat exchanger cleaning and repair.

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

(w) Flue gas conditioning systems and associated chemicals such as the following: Ammonia.

(x) Blowdown for any of the following: sight glass; boiler; compressors; pumps; and cooling tower.

(y) Paved and unpaved roads and parking lots with public access. [326 IAC 6-4]

(z) Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors and electrostatic precipitators with a design grain loading of less than or equal to 0.03 grains per actual cubic foot and a gas flow rate less than or equal to 4000 actual cubic feet per minute, including the following: deburring; buffing; polishing; abrasive blasting; pneumatic conveying; and woodworking operations. [326 IAC 6-3]

The following construction conditions are applicable to the proposed project:

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.

3. Effective Date of the Permit
Pursuant to IC 13-15-5-3, this approval becomes effective upon its issuance.

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.

This decision is subject to the Indiana Administrative Orders and Procedures Act – IC 4-21.5-3-5. If you have any questions on this matter, please contact Josiah Balogun, OAQ, 100 North Senate Avenue, MC 61-53, Room 1003, Indianapolis, Indiana, 46204-2251, or call at (800) 451-6027, and ask for Josiah Balogun or extension (4-5257), or dial (317) 234-5257.

Sincerely,

Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

Attachments:
Updated Permit
Technical Support Document
PTE Calculations
BACT Analysis
Attachment A, B, C and D
Air Quality Analysis
JB

cc: File – St. Joseph County
St. Joseph County Health Department
U.S. EPA, Region V
Northern Regional Office
Compliance and Enforcement Branch

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

OFFICE OF AIR QUALITY

St. Joseph Energy Center, LLC
Corner of Walnut and Edison Roads
New Carlisle, Indiana 46552

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

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

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

Operation Permit No.: T141-31003-00579	
Issued by:	Issuance Date: December 3, 2012
Matthew Stuckey, Branch Chief Permits Branch Office of Air Quality	Expiration Date: December 3, 2017

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New Source Performance Standards [326 IAC 12][40 CFR 60, Subpart KKKK]
E.1.1 General Provisions Relating to New Source Performance Standard [326 IAC 12-1][40 CFR Part 60, Subpart A]
E.1.2 New Source Performance Standard for Stationary Combustion Turbines Requirements [40 CFR Part 60, Subpart KKKK] [326 IAC 12]

E.2. EMISSIONS UNIT OPERATION CONDITIONS

New Source Performance Standards [326 IAC 12][40 CFR 60, Subpart Dc]
E.2.1 General Provisions Relating to New Source Performance Standard [326 IAC 12-1][40 CFR Part 60, Subpart A]
E.2.2 New Source Performance Standard for Small-Commercial-Institutional Steam Generating Units Requirements [40 CFR Part 60, Subpart Dc] [326 IAC 12]

E.3. EMISSIONS UNIT OPERATION CONDITIONS

New Source Performance Standards [326 IAC 12][40 CFR 60, Subpart IIII]
E.3.1 General Provisions Relating to NSPS IIII [326 IAC 12][40 CFR Part 60, Subpart A]
E.3.2 Standard of Performance for Stationary Compression Inginition Internal Combustion Engines [326 IAC 12][40 CFR Part 60, Subpart IIII]

E.4. EMISSIONS UNIT OPERATION CONDITIONS

National Emission Standard for Hazardous Air Pollutants [326 IAC 20][40 CFR 63, Subpart ZZZZ]

E.4.1 General Provisions Relating to National Emissions Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [326 IAC 20-1][40 CFR Part 63, Subpart A]

E.4.1 National Emissions Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [40 CFR Part 63, Subpart ZZZZ] [326 IAC 20-82-1]

SECTION F Clean Air Interstate (CAIR) Nitrogen Oxides Annual, Sulfur Dioxide, and Nitrogen Oxides Ozone Season Trading Programs – CAIR Permit for CAIR Units Under 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a)

F.1 Automatic Incorporation of Definitions [326 IAC 24-1-7(e)] [326 IAC 24-2-7(e)]

[326 IAC 24-3-7(e)] [40 CFR 97.123(b)] [40 CFR 97.223(b)] [40 CFR 97.323(b)]
F.2 Standard Permit Requirements [326 IAC 24-1-4(a)] [326 IAC 24-2-4(a)] [326 IAC 24-3-4(a)] [40 CFR 97.106(a)] [40 CFR 97.206(a)] [40 CFR 97.306(a)]
F.3 Monitoring, Reporting, and Record Keeping Requirements [326 IAC 24-1-4(b)] [326 IAC 24-2-4(b)] [326 IAC 24-3-4(b)] [40 CFR 97.106(b)] [40 CFR 97.206(b)] [40 CFR 97.306(b)]
F.4.1 Nitrogen Oxides Emission Requirements [326 IAC 24-1-4(c)] [40 CFR 97.106(c)]
F.4.2 Sulfur Dioxide Emission Requirements [326 IAC 24-2-4(c)] [40 CFR 97.206(c)]
F.4.3 Nitrogen Oxides Ozone Season Emission Requirements [326 IAC 24-3-4(c)] [40 CFR 97.306(c)]
F.5 Excess Emissions Requirements [326 IAC 24-1-4(d)] [326 IAC 24-2-4(d)] [326 IAC 24-3-4(d)] [40 CFR 97.106(d)] [40 CFR 97.206(d)] [40 CFR 97.306(d)]
F.6 Record Keeping Requirements [326 IAC 24-1-4(e)] [326 IAC 24-2-4(e)] [326 IAC 24-3-4(e)] [326 IAC 2-7-5(3)] [40 CFR 97.106(e)] [40 CFR 97.206(e)] [40 CFR 97.306(e)]
F.7 Reporting Requirements [326 IAC 24-1-4(e)] [326 IAC 24-2-4(e)] [326 IAC 24-3-4(e)] [40 CFR 97.106(e)] [40 CFR 97.206(e)] [40 CFR 97.306(e)]
F.8 Liability [326 IAC 24-1-4(f)] [326 IAC 24-2-4(f)] [326 IAC 24-3-4(f)] [40 CFR 97.106(f)] [40 CFR 97.206(f)] [40 CFR 97.306(f)]
F.9 Effect on Other Authorities [326 IAC 24-1-4(g)] [326 IAC 24-2-4(g)] [326 IAC 24-3-4(g)] [40 CFR 97.106(g)] [40 CFR 97.206(g)] [40 CFR 97.306(g)]
F.10 CAIR Designated Representative and Alternate CAIR Designated Representative [326 IAC 24-1-6] [326 IAC 24-2-6] [326 IAC 24-3-6] [40 CFR 97, Subpart BB] [40 CFR 97, Subpart BBB] [40 CFR 97, Subpart BBBB]

Certification
Emergency Occurrence Report
Quarterly Report
Quarterly Deviation and Compliance Monitoring Report
Affidavit of Construction

Attachment A - NSPS 40 CFR 60, Subpart Dc
Attachment B - NSPS 40 CFR 60, Subpart IIII
Attachment C - NSPS 40 CFR 60, Subpart KKKK
Attachment D - NESHAP 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.3 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

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

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

Source Address:	Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
General Source Phone Number:	914-468-2402
SIC Code:	4991
County Location:	St. Joseph
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules Minor Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

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

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

(a) Four (4) natural gas-fired combined cycle combustion turbines, identified as units CCCT1, CCCT2, CCCT3, and CCCT4, permitted in 2012, each with a combustion turbine equipped with dry low NOx burners, natural gas fired duct burners, and a heat recovery steam generator identified as HRSG1, HRSG2, HRSG3, and HRSG4, NOx emissions controlled by four (4) selective catalytic reduction (SCR) systems (SCR01, SCR02, SCR03 and SCR04), CO and VOC emissions controlled by oxidation catalyst systems (CAT01, CAT02, CAT03 and CAT04) and exhausting to stacks CCCT01, CCCT02, CCCT03, and CCCT04, respectively. Each stack has continuous emissions monitors (CEMS) for NOx and CO. The nominal heat input for each CCCT is 2,300 MMBtu/hr (higher heating value (HHV)). The combined nominal power output is 1,350 megawatts (MW).

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

(b) Two (2) natural gas fired auxiliary boilers, identified as B001 and B002, permitted in 2012, each, with a maximum heat input capacity of 80 MMBtu/hr (HHV), equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stacks B001 and B002. Under 40 CFR Part 60, Subpart Dc, the auxiliary boiler is considered a steam generating unit.

(c) One (1) emergency diesel generator, nominally rated at 2012 horsepower, identified as EG03, permitted in 2012, exhausting through one (1) vent, identified as EG03. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generator is considered a new affected source.]

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

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

(a) Two (2) firewater pump engines, each nominally rated at 371 brake horsepower (bph) and identified as FP01 and FP02, permitted in 2012, exhausting through two (2) vents, identified as FP01 and FP02, respectively. [Under 40 CFR 60, Subpart IIII, the firewater pump engines are considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the firewater pump engines are considered new affected sources.]

(b) Two (2) emergency diesel generators, each nominally rated at 1,006 horsepower, identified as EG01 and EG02, permitted in 2012, exhausting through two (2) vents, identified as EG01 and EG02, respectively. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generators are considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generators are considered new affected source.]

(c) Two (2) cooling towers, each nominally rated with a circulation rate of 170,000 gpm , identified as CT01 and CT02, permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through ten vents each, identified as CT01A – CT01J and CT02A – CT02J.

(d) Six (6) Turbine Lube Demister Vents, identified as DM01 - DM06, permitted in 2012, exhausting through vents DM01 – DM06.

(e) Six (6) Turbine Lube Oil storage tanks, identified as TK01 - TK06, permitted in 2012, each with a nominal capacity of 6,800 gallons.

(f) Two (2) Emergency Generator ULSD Tanks, identified as TK07 and TK08, permitted in 2012, each with a nominal capacity of 550 gallons.

(g) Two (2) Fire Pump Engine ULSD Tanks, identified as TK09 and TK10, permitted in 2012, each with a nominal capacity of 70 gallons.

(h) One (1) Vehicle Gasoline dispensing Tank, identified as TK11, permitted in 2012, with a nominal capacity of 650 gallons, equipped with submerged fill and stage 1 vapor balance.

(i) One (1) Vehicle Diesel Tank, identified as TK12, permitted in 2012, with a nominal capacity of 650 gallons.

(j) One (1) Emergency Generator ULSD Tank, identified as TK50, permitted in 2012, with a nominal capacity of 300 gallons;

(k) two (2) lime storage silos, capable of handling a maximum loading rate of 20 tons per hour combined, permitted in 2012 and with particulate matter controlled by bin vent filters exhausting to Stacks S1 and S2;

(l) Six (6) Electrical Circuit Breakers containing sulfur hexafluoride (SF_6) identified as emissions unit SF6, permitted in 2012, with fugitive GHG emissions;

(m) Degreasing operations that do not exceed one hundred forty-five (145) gallons per 12 months, except if subject to 326 IAC 20-6. [326 IAC 8-3]; and

(n) Paved and unpaved roads and parking lots with public access. [326 IAC 6-4]

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

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

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

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

(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, T141-31003-00579, 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(34), 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(34).

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 April 15 of each year to:

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

and

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

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

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

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

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

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

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

The submittal by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

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

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

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

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

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

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

The PMP extension notification does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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(34).

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

B.13 Emergency Provisions [326 IAC 2-7-16]

(a) An emergency, as defined in 326 IAC 2-7-1(12), is not an affirmative defense for an action brought for noncompliance with a federal or state health-based emission limitation.

(b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describe the following:

(1) An emergency occurred and the Permittee can, to the extent possible, identify the causes of the emergency;

(2) The permitted facility was at the time being properly operated;

(3) During the period of an emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ, or Northern Regional Office within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance and Enforcement Branch), or
Telephone Number: 317-233-0178 (ask for Office of Air Quality, Compliance and Enforcement Branch)
Facsimile Number: 317-233-6865
Northern Regional Office phone: (574) 245-4870; fax: (574) 245-4877**.**

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

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

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

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

(A) A description of the emergency;

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

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

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

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

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

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

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

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

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

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

(b) 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 T141-31003-00579 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(34).

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

(1) That this permit contains a material mistake.

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

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

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

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

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

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(40). The renewal application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

Request for renewal shall be submitted to:

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

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

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

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

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

B.19 Permit Amendment or Modification [326 IAC 2-7-11][326 IAC 2-7-12] [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
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

(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
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

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

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

(5) The Permittee maintains records on-site, on a rolling five (5) year basis, which document all such changes and emission trades that are subject to

326 IAC 2-7-20(b) or (c). The Permittee shall make such records available, upon reasonable request, for public review.

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

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

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

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

(3) Any change in emissions; and

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

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

(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 or 326 IAC 10-4.

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

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

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

Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee's right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as

such, the Permittee shall allow IDEM, OAQ, U.S. EPA, or an authorized representative to perform the following:

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

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

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

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

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

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

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

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

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

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

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

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

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

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

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

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

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

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

C.1 Opacity [326 IAC 5-1]

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

(a) Opacity shall not exceed an average of thirty percent (30%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

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

C.2 Open Burning [326 IAC 4-1] [IC 13-17-9]

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

C.3 Incineration [326 IAC 4-2] [326 IAC 9-1-2]

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

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

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

C.5 Stack Height [326 IAC 1-7]

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

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

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

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

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

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

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

(A) Asbestos removal or demolition start date;

(B) Removal or demolition contractor; or

(C) Waste disposal site.

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

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

All required notifications shall be submitted to:

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

The notice shall include a signed certification from the owner or operator that the information provided in this notification is correct and that only Indiana licensed workers and project supervisors will be used to implement the asbestos removal project. The notifications do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

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

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

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

C.7 Performance Testing [326 IAC 3-6]

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

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

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

(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(34).

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

Compliance Requirements [326 IAC 2-1.1-11]

C.8 Compliance Requirements [326 IAC 2-1.1-11]

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

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

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

Unless otherwise specified in this permit, for all monitoring requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance or of initial start-up, whichever is later, to begin such monitoring. If due to circumstances beyond the Permittee's control, any monitoring equipment required by this permit cannot be installed and operated no later than ninety (90) days after permit issuance or the date of initial startup, whichever is later, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:

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

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

The notification which shall be submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

C.10 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

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

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

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

C.11 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]

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

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

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

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

100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

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

The ERP does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

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

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

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

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

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

(1) initial inspection and evaluation;

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

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

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

(1) monitoring results;

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

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

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

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

C.14 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5][326 IAC 2-7-6]

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

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

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

The response action documents submitted pursuant to this condition do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

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

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

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

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

The statement must be submitted to:

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

The emission statement does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

C.16 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [326 IAC 2-2] [326 IAC 2-3]

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

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

Records of required monitoring information include the following:

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

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

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

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

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

(A) A description of the project.

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

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

(i) Baseline actual emissions;

(ii) Projected actual emissions;

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

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

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

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

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

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

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under Section B –Emergency Provisions satisfies the reporting requirements of this paragraph. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported except that a deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported

according to the schedule stated in the applicable requirement and does not need to be included in this report. This report shall be submitted not later than thirty (30) days after the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

(b) The address for report submittal is:

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

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

(d) 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
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

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

Stratospheric Ozone Protection

C.18 Compliance with 40 CFR 82 and 326 IAC 22-1

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

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

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

(a) Four (4) natural gas-fired combined cycle combustion turbines, identified as units CCCT1, CCCT2, CCCT3, and CCCT4, permitted in 2012, each with a combustion turbine equipped with dry low NOx burners, natural gas fired duct burners, and a heat recovery steam generator identified as HRSG1, HRSG2, HRSG3, and HRSG4, NOx emissions controlled by four (4) selective catalytic reduction (SCR) systems (SCR01, SCR02, SCR03 and SCR04), CO and VOC emissions controlled by oxidation catalyst systems (CAT01, CAT02, CAT03 and CAT04) and exhausting to stacks CCCT01, CCCT02, CCCT03, and CCCT04, respectively. Each stack has continuous emissions monitors (CEMS) for NOx and CO. The nominal heat input for each CCCT is 2,300 MMBtu/hr (higher heating value (HHV)). The combined nominal power output is 1,350 megawatts (MW).

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

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

Construction Conditions

General Construction Conditions

D.1.1 Permit No Defense

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

Effective Date of the Permit

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

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

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

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

Operating Conditions

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

D.1.4 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines, identified as CCCT1, CCCT2, CCCT3, and CCCT4 shall be as follows:

(a) The PM, PM_{10} and $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as CCCT1 -CCCT4 shall not exceed 18 pounds per hour and 0.0078 lbs/MMBtu, with duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

(b) The PM, PM_{10} and $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as CCCT1 -CCCT4 shall not exceed 15 pounds per hour and 0.0092 lbs/MMBtu, without duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

D.1.5 H_2SO_4 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines , identified as CCCT1, CCCT2, CCCT3, and CCCT4 shall be as follows:

The H_2SO_4 emissions from the combined cycle combustion turbines identified as CCCT1 - CCCT4 shall be limited by a fuel sulfur limit of 0.75 gr S/100 scf fuel.

D.1.6 CO PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines , identified as CCCT1, CCCT2, CCCT3, and CCCT4 shall be as follows:

(a) The CO emissions from the CCCTs shall be controlled by a catalytic oxidation; and

(b) The CO emissions shall not exceed 2.0 ppmv @15% O2 based on a 3-hr average.

These conditions do not apply during startup and shutdown, as defined in Condition D.1.11.

D.1.7 SO_2 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines , identified as CCCT1, CCCT2, CCCT3, and CCCT4 shall be as follows:

The SO_2 emissions from the combined cycle combustion turbines identified as CCCT1 - CCCT4 shall be limited by a fuel sulfur limit of 0.75 gr S/100 scf fuel.

D.1.8 VOC PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines , identified as CCCT1, CCCT2, CCCT3, and CCCT4 shall be as follows:

(a) The VOC emissions from the CCCTs shall be controlled by a catalytic oxidation

(b) The VOC emissions shall not exceed 2.0 ppmvd @15% O_2, with duct burners based on 3-hr average.

(c) The VOC emissions shall not exceed 1.0 ppmvd @15% O_2, without duct burners based on 3-hr average.

These conditions do not apply during startup and shutdown, as defined in Condition D.1.11.

D.1.9 NOx PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines, identified as CCCT1, CCCT2, CCCT3, and CCCT4 shall be as follows:

(a) The NOx emissions from the CCCTs shall be controlled by a Selective Catalytic Reduction and DLN Burners.

(b) The NOx emissions shall not exceed 2.0ppmv @15% O_2 with duct burners based on a 3-hr average.

These conditions do not apply during startup and shutdown, as defined in Condition D.1.11.

D.1.10 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired combined cycle combustion turbines, identified as CCCT1, CCCT2, CCCT3, and CCCT4 shall be as follows:

(a) The net heat rate shall not exceed 7,646 Btu/kW-hr (HHV-net) for each CCCT block (ISO conditions, baseload operation without duct firing or inlet evaporative cooling, and not accounting for transformer losses).

(b) The total CO_2 emissions from all four CCCT blocks shall not exceed 4,736,936 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

D.1.11 Startup and Shutdown Limitations for Combustion Turbines [326 IAC 2-2-3]

Pursuant to PSD/New Source Review Permit No. 141-31003-00579 and 326 IAC 2-2-3 (PSD Requirements), following applies to each combustion 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 consecutive CEMS data points in compliance with the primary BACT limits.

(b) Steady-state operating condition shall be defined as the period of time that the combustion turbine is operating in dry low NOx (premix) mode and in compliance with the primary BACT limit.

(c) A shutdown is defined as operation beginning when the combustion turbine exits dry low-NOx (premix) mode and ending with termination of continuous fuel flow to each turbine.

(d) A startup/shutdown cycle is a pair of subsequent shutdown and startup events (i.e., one startup followed by one shutdown represents one startup/shutdown cycle).

(e) Unit Offline is represented by the Unit on-line Time being 0.

(f) 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.

(g) An event is defined as:

(1) exactly one (1) startup or exactly one (1) shutdown

For CO and NO_X, the source determined the worst-case operating scenario that results in the highest modeled impacts to be a cold start of the CCCTs. The modeled cold start emission rates are based on startup emission totals provided by the turbine vendor. Therefore, the source proposes to use the cold start emission totals, per CCCT as a short-term limit during startup/shutdown events, as follows:

CO - 2,125 lb/event
NOx - 443 lb/event

(h) The NO_X emissions from the combined cycle combustion turbines stacks shall not exceed 81.6 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.

(i) The CO emissions from the combined cycle combustion turbines stacks shall not exceed 407.5 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.

(j) The VOC emissions from the combined cycle combustion turbines stacks shall not exceed 22.0 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.1.12 Preventive Maintenance Plan [326 IAC 1-6-3]

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

Compliance Determination Requirements

D.1.13 Nitrogen Oxide Control

In order to ensure compliance with Condition D.1.9 - NOx PSD BACT, the Low NOx burner shall be in operation and control emissions from the natural gas-fired combustion turbines at all times that the natural gas-fired combined cycle combustion turbines are in operation.

D.1.14 Oxidation Catalyst

In order to ensure compliance with Conditions D.1.6 and D.1.8, the oxidation catalyst shall be in operation at all times when the natural gas-fired combined cycle combustion turbinesare in operation.

D.1.15 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.1.10, the following equation shall be used to determine the CO_2e emissions from the natural gas-fired combined cycle combustion turbines, identified as CCCT1, CCCT2, CCCT3, and CCCT4:

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)

D.1.16 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 3-5][326 IAC-2-2-3]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment for NOx and CO emissions.

(b) 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.

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

(d) Whenever a NOx, or CO CEM is down for more than twenty-four (24) hours, the Permittee shall follow good air pollution control practices.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 40 CFR 60, 40 CFR 75 and 40 CFR 96.

D.1.17 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.1.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct PM, PM_{10} and $PM_{2.5}$ emissions stack testing of the emissions from the combined cycle combustion turbines utilizing methods as approved by the commissioner. Testing shall be conducted with and without the duct burners in operation. This test shall be repeated at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(b) In order to demonstrate compliance with Condition D.1.8 - VOC PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct VOC emissions stack testing of the emissions from the combined cycle combustion turbines utilizing methods as approved by the commissioner. Testing shall be conducted with and without the duct burners in operation. This test shall be repeated at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(c) In order to demonstrate compliance with Condition D.1.10(a) - GHGs PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct net heat rate performance testing for combined cycle combustion turbines utilizing methods as approved by the commissioner. This test shall be repeated at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

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

D.1.18 Oxidation Catalyst Parametric Monitoring

(a) In order to ensure compliance with Condition D.1.8 - VOC PSD BACT, a continuous monitoring system shall be calibrated, maintained, and operated on each oxidation catalyst for measuring operating temperature. For the purposes 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 the start up of the oxidation catalyst until the approved stack test results are

available, the Permittee shall operate the oxidation catalyst at or above the 3-hour average temperature of 500°F.

(b) 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 specified by the catalyst manufacturer for VOC control or as established during the most recent compliant stack test.

(c) Section C - Response to Excursions or Exceedences contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A temperature average below the three hour average specified by the catalyst manufacturer for VOC control or as established in the most recent compliance stack test is not considered a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit.

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

D.1.19 Record Keeping Requirement

(a) To document the compliance status with Condition D.1.16 - Maintenance of Continuous Emission Monitoring Equipment, the Permittee shall record the output of the continuous monitoring systems and shall perform the required record keeping and reporting, pursuant to 326 IAC 3-5-6 and 326 IAC 3-5-7.

(b) In the event that a breakdown of the NOx or CO continuous emission monitoring system (CEMS) occurs in Condition D.1.16 - Maintenance of Continuous Emission Monitoring Equipment, the Permittee shall maintain records of all CEMS malfunctions, out of control periods, calibration and adjustment activities, and repair or maintenance activities.

(c) To document the compliance status with Conditions D.1.16 - Maintenance of Continuous Emission Monitoring Equipment, the Permittee shall maintain the monthly records of the CO and NOx emissions from each of the combined cycle combustion turbines CCCT1 through CCCT4 based the CEM data. Compliance with the CO emissions shall satisfy for the VOC emissions.

(d) To document compliance with Condition D.1.11 - Startup and Shutdown Limitations for Combustion Turbines, 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.

(e) In order to document the compliance status with Conditions D.1.4, D.1.5, D.1.6, D.1.7, D.1.8, D.1.9 and D.1.10, the Permittee shall maintain monthly records of the amount and type of fuel combusted in the combined cycle combustion turbines.

(f) To document the compliance status with Condition D.1.10 - GHGs PSD BACT, the Permittee shall maintain monthly records of the CO_{2e} emissions.

(g) In order to document the compliance status with Condition D.1.18 - Oxidation Catalyst Parametric Monitoring, the Permittee shall maintain continuous temperature records (on a three- (3-) hourly average basis) for each oxidation catalyst to demonstrate compliance.

(h) To document the compliance status with Condition D.1.5 - H_2SO_4 PSD BACT and D.1.7 - SO_2 PSD BACT, the Permittee shall maintain the monthly records of the fuel sulfur content of the natural gas combusted in the turbines and the associated duct burners.

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

D.1.20 Reporting Requirements

A quarterly summary of the information to document the compliance status with Conditions D.1.10(b), D.1.11(i), D.1.11(j), D.1.11(k) and D.1.11(l) shall be submitted using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

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

(b) Two (2) natural gas fired auxiliary boilers, identified as B001 and B002, permitted in 2012, each, with a maximum heat input capacity of 80 MMBtu/hr (HHV), equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stacks B001 and B002. Under 40 CFR Part 60, Subpart Dc, the auxiliary boiler is considered a steam generating unit.

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

Construction Conditions

General Construction Conditions

D.2.1 Permit No Defense

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

Effective Date of the Permit

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

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

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

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

Operating Conditions

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

D.2.4 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as B001 and B002 shall be as follows:

The PM, PM_{10} and $PM_{2.5}$ emissions from the Auxiliary Boilers, identified as B001-B002 shall not exceed 0.0075 lb/MMBtu (HHV) and 0.6 lbs/hour, each, based on a 3-hr average period through the use of good combustion practices and fuel specification.

D.2.5 CO PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as B001 and B002 shall be as follows:

The CO emissions from the Auxiliary Boilers (B001-B002) operation shall not exceed 0.083 lb/MMBtu (HHV) and 6.64 lbs/hr, each, based on a 3 - hour average through Good Combustion Practices.

D.2.6 SO_2 PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as B001 and B002 shall be as follows:

The SO_2 emissions from the Auxiliary Boilers, identified as B001-B002 shall not exceed 0.0022 lb/MMBtu (HHV) and 0.176 lbs/hr each, based on a 3-hr average through the use of fuel specification.

D.2.7 NOx PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as B001 and B002 shall be as follows:

(a) The NOx emissions from the Auxiliary Boilers, identified as B001-B002 shall be controlled by a Low NOx Burner with Flue Gas Recirculation.

(b) The NOx emissions shall not exceed 0.032 lb/MMBtu (HHV) and 2.56 pounds per hour each, based on a 3-hr average period.

D.2.8 VOC PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as B001 and B002 shall be as follows:

The VOC emissions from the Auxiliary Boilers, identified as B001-B002 shall not exceed 0.005 lb/MMBtu (HHV) and 0.4 lbs/hr each based on a 3-hr average period through the use of good combustion practices.

D.2.9 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the natural gas-fired auxiliary boiler, identified as B001 and B002 shall be as follows:

The GHGs BACT for the Auxiliary Boilers shall be as follows:

(a) Operating and Maintenance (O&M) Practices;

(b) Combustion Turning;

(c) The boiler will be equipped with oxygen trim controls and oxygen analyzers;

(d) The boiler will be equipped with an economizer;

(e) Energy efficient refractory will be installed;

(f) The boiler will be equipped with a condensate return system (recovery);

(g) Steam and hot lines will be insulated;

(h) Boiler designed for 80% thermal efficiency (HHV); and

(i) The total CO_{2e} emissions from the two auxiliary boilers shall be limited to less than 81,996 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

D.2.10 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.2.11 Preventive Maintenance Plan [326 IAC 1-6-3]

A Preventive Maintenance Plan (PMP) is required for these units and control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.2.12 Nitrogen Oxide Control

In order to ensure compliance with Condition D.2.7 - NOx PSD BACT, the low NOx burner shall be installed and utilized at all times that the auxiliary boilers are in operation.

D.2.13 Testing Requirements [326 IAC 2-1.1-11]

(a) In order to demonstrate compliance with Condition D.2.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct PM, PM_{10} and $PM_{2.5}$ emissions stack testing of the emissions from the boilers utilizing methods as approved by the commissioner. This test shall be performed once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(b) In order to demonstrate compliance with Condition D.2.5 - CO PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct CO emissions stack testing of the emissions from the boilers utilizing methods as approved by the commissioner. This test shall be performed once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(c) In order to demonstrate compliance with Condition D.2.7 - NOx PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct NOx emissions stack testing of the emissions from the boilers utilizing methods as approved by the commissioner. This test shall be repeated at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(d) In order to demonstrate compliance with Condition D.2.8 - VOC PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct VOC emissions stack testing of the emissions from the boilers utilizing methods as approved by the commissioner. This test shall be repeated at least once every five years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(e) In order to demonstrate compliance with Condition D.2.9(h) – GHGs PSD BACT, within sixty (60) days of reaching maximum capacity but no later than 180 days after initial startup, the Permittee shall perform thermal efficiency testing of the auxiliary boilers, identified as B001 and B002 utilizing methods approved by the Commissioner. These tests shall be conducted once. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.2.14 Compliance Determination Requirements [326 IAC 2-2]

In order to determine compliance status with Conditions D.2.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT and D.2.6 - SO_2 PSD BACT, the Permittee shall only use natural gas in the auxiliary boilers B001 and B002.

D.2.15 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Condition D.2.9(i), the following equation shall be used to determine the CO_{2e} emissions from the Auxiliary Boilers:

CO_2e emissions (ton/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)

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

D.2.16 Record Keeping Requirements

(a) In order to document the compliance status with Conditions D.2.4, D.2.5, D.2.6, D.2.7, D.2.8, D.2.9, and D.2.14, the Permittee shall maintain monthly records of the type and amount of fuel combusted in the auxiliary boilers.

(b) To document the compliance status with Condition D.2.9(i) - GHGs PSD BACT, the Permittee shall maintain the monthly records of the total CO_{2e} emissions from the auxiliary boilers.

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

D.2.17 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.2.9(i) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: [326 IAC 2-7-5(14) **Insignificant Activities**

(a) Two (2) firewater pump engines, each nominally rated at 371 brake horsepower (bph) and identified as FP01 and FP02, permitted in 2012, exhausting through two (2) vents, identified as FP01 and FP02, respectively. [Under 40 CFR 60, Subpart IIII, the firewater pump engines are considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the firewater pump engines are considered new affected sources.]

(b) Two (2) emergency diesel generators, each nominally rated at 1,006 horsepower, identified as EG01 and EG02, permitted in 2012, exhausting through two (2) vents, identified as EG01 and EG02, respectively. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generators are considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generators are considered new affected source.]

(c) One (1) emergency diesel generator, nominally rated at 2012 horsepower, identified as EG03, permitted in 2012, exhausting through one (1) vent, identified as EG03. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generator is considered a new affected source.]

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

Construction Conditions

General Construction Conditions

D.3.1 Permit No Defense

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

Effective Date of the Permit

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

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

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

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

Operating Conditions

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

D.3.4 PM, PM_{10}, $PM_{2.5}$, NOx, CO, SO_2 and GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the two (2) firewater pump diesel engines, identified as FP01 and FP02 shall be as follows:

Firewater Pump Engines, identified as FP01 - FP02:

(a) The PM, PM_{10} and $PM_{2.5}$ emissions from the Firewater Pump Engines identified as FP01 - FP02 shall be limited to less than 0.15 g/hp-hr through the use of combustion design control and usage limitation.

(b) The CO emissions from the Firewater Pump Engines identified as FP01 - FP02 shall not exceed 2.6 g/hp-hr through the use of combustion design control and usage limitation.

(c) The SO_2 emissions from the Firewater Pump Engines identified as FP01 - FP02 shall not exceed 0.0015 % S and 0.043 lb/hr, each through the use of ultra low sulfur distillate (ULSD) and usage limitation.

(d) The VOC emissions from the Firewater Pump Engines identified as FP01 - FP02 shall not exceed 0.16 pounds per hour, each through the use of Combustion Design Controls and usage limitation.

(e) The NOx emissions from the Firewater Pump Engines identified as FP01 - FP02 shall not exceed 3.0 g/bhp-hr for NOx + NMHC through the use of Combustion Design Controls and usage limitation.

(f) The GHGs BACT for the Firewater Pump Engines identified as FP01 - FP02 shall be as follows;

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

(2) The total CO_{2e} emissions from all the two (2) firewater pump engines shall not exceed 172 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

(g) The Firewater Pumps identified as FP01 - FP02 shall not exceed 500 hours per year, each.

D.3.5 PM, PM_{10}, $PM_{2.5}$, NOx, CO, SO_2 and GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the three (3) emergency diesel generators, identified as EG01, EG02 and EG03 shall be as follows:

Emergency Diesel Generators, identified as (EG01 - EG03):

(a) The PM, PM_{10} and $PM_{2.5}$ emissions from the Emergency Diesel Generators, Identified as EG01, EG02 and EG03 shall not exceed 0.15 g/hp-hr, each through the use of combustion design control and usage limitation.

(b) The CO emissions from the Emergency Diesel Generators, Identified as EG01, EG02 and EG03 shall not exceed 2.6 g/hp-hr, each through the use of combustion design controls and usage limitation.

(c) The SO_2 emissions from the Emergency Diesel Generators, Identified as EG01 and EG02 shall not exceed 0.012 lb/hr, each, through the use of ultra low sulfur distillate (ULSD) and usage limitation.

(d) The SO_2 emissions from the Emergency Diesel Generator, Identified as EG03 shall not exceed 0.024 lb/hr through the use of ultra low sulfur distillate (ULSD) and usage limitation.

(e) The VOC emissions from the Emergency Diesel Generators, Identified as EG01 and EG02 shall not exceed 1.04 lbs/hr, each, through the use of Combustion Design Controls and usage limitation.

(f) The VOC emissions from the Emergency Diesel Generator, Identified as EG03 shall not exceed 1.04 lbs/hr through the use of Combustion Design Controls and usage limitation.

(g) The NOx emissions from the Emergency Diesel Generators shall not exceed 4.8 g/bhp-hr for NOx + NMHC through the use of Combustion Design Controls and usage limitation.

(h) The GHGs BACT for the Emergency Diesel Generators, Identified as EG01, EG02 and EG03 shall be as follows;

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

(2) The total CO_2 emissions from all the three (3) emergency diesel generators shall not exceed 1,186 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

(i) The Emergency Diesel Generators, Identified as EG01, EG02 and EG03 shall not exceed 500 hours per year, each.

Compliance Determination Requirements

D.3.6 Greenhouse Gases (GHGs) Calculations

To determine the compliance status with Conditions D.3.4(f)(2) and D.3.5(h)(2), the following equation shall be used to determine the CO_{2e} emissions from the emergency diesel engines (FP01-FP02 and EG01 - EG03):

CO_2e emissions (ton/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.3.7 Record Keeping Requirements

(a) In order to document the compliance status with Conditions D.3.4(c), D3.5(c) and (d), the Permittee shall maintain monthly records of the percent sulfur content of the fuel used in the emergency diesel engines and the firewater pump diesel engines.

(b) To document compliance with Conditions D.3.4(g) and D.3.5(i), the Permittee shall maintain monthly records of hours of operation of the emergency diesel engines and the firewater pump diesel engines.

(c) To document the compliance status with Conditions D.3.4(f)(2), D.3.5(h)(2) and D.3.6, the Permittee shall maintain records of the total amount of fuel used each month in the emergency diesel engines (FP01-FP02 and EG01-EG03) and the total CO_2 emissions from the emergency diesel engines (FP01-FP02 and EG01-EG03).

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

D.3.8 Reporting Requirements

A quarterly summary of the information to document the compliance status with Conditions D.3.4(f)(2), D.3.4(g), D.3.5(h)(2) and D.3.5(i) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: [326 IAC 2-7-5(14) **Insignificant Activities**

(c) Two (2) cooling towers, each nominally rated with a circulation rate of 170,000 gpm , identified as CT01 and CT02, permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through ten vents each, identified as CT01A – CT01J and CT02A – CT02J.

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

Construction Conditions

General Construction Conditions

D.4.1 Permit No Defense

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

Effective Date of the Permit

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

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

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

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

Operating Conditions

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

D.4.4 PM, PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Cooling Tower CT01 and CT02 shall be as follows:

The PM, PM_{10} and $PM_{2.5}$ emissions from the Cooling Towers, identified as CT01 and CT02 shall be controlled by High efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.

Compliance Determination

D.4.5 PM, PM_{10} and $PM_{2.5}$ Control

In order to ensure compliance with Condition D.4.4 - PM, PM_{10} and $PM_{2.5}$ PSD BACT, the high efficiency drift eliminators for particulate control shall be in operation and control emissions from each cooling tower at all times that the cooling towers are in operation.

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: [326 IAC 2-7-5(14) **Insignificant Activities**

(e) Six (6) Turbine Lube Demister Vents, identified as DM01 - DM06, permitted in 2012, exhausting through vents DM01 – DM06.

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

Construction Conditions

General Construction Conditions

D.5.1 Permit No Defense

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

Effective Date of the Permit

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

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

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

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

Operating Conditions

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

D.5.4 PM_{10} and $PM_{2.5}$ PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Storage Tanks, identified as DM01 – DM06 shall be as follows:

The organic PM, PM_{10} and $PM_{2.5}$ emissions from the Turbine Lube Oil Demister Vents, identified as DM01 – DM06, shall be the use of good design and operating practices.

D.5.5 Volatile Organic Compounds (VOC) PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Turbine Lube Oil Demister Vents, identified as DM01 – DM06, shall be as follows:

The VOC emissions from the Lubrication Turbine Lube Oil Demister Vents, identified as DM01 – DM06, shall be the use of good design and operating practices.

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: [326 IAC 2-7-5(14) **Insignificant Activities**

(e) Six (6) Turbine Lube Oil storage tanks, identified as TK01 - TK06, permitted in 2012, each with a nominal capacity of 6,800 gallons.

(f) Two (2) Emergency Generator ULSD Tanks, identified as TK07 and TK08, permitted in 2012, each, with a nominal capacity of 550 gallons.

(g) Two (2) Fire Pump Engine ULSD Tanks, identified as TK09 and TK10, permitted in 2012, each, with a nominal capacity of 70 gallons.

(h) One (1) Vehicle Gasoline dispensing Tank, identified as TK11, permitted in 2012, with a nominal capacity of 650 gallons, equipped with submerged fill and stage 1 vapor balance.

(i) One (1) Vehicle Diesel Tank, identified as TK12, permitted in 2012, with a nominal capacity of 650 gallons.

(j) One (1) Emergency Generator ULSD Tank, identified as TK50, permitted in 2012, with a nominal capacity of 300 gallons.

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

Construction Conditions

General Construction Conditions

D.6.1 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 thereunder, as well as other applicable local, state, and federal requirements.

Effective Date of the Permit

D.6.2 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.6.3 Modification to Construction Conditions [326 IAC 2]

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

Operating Conditions

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

D.6.4 Volatile Organic Compounds (VOC) PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the Turbine Lube Oil storage tanks, identified as TK01 - TK06, and Diesel Storage Tanks, identified as TK07, TK08, TK09, TK10, TK12 and TK50 shall be as follows:

The VOC emissions from the Turbine Lube Oil storage tanks, identified as TK01 - TK06, and Diesel Storage Tanks, identified as TK07, TK08, TK09, TK10, TK12 and TK50 shall be the use of good design and operating practices.

D.6.5 Prevention of Significant Deterioration (PSD) – Best Available Control Technology for Volatile Organic Compounds (VOC) [326 IAC 2-2-3] [326 IAC 8-4-6]

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for the Gasoline Dispensing Facility, identified as TK11 shall be as follows:

(a) The Permittee shall not allow the transfer of gasoline between any transport and any gasoline storage tank unless such tank is equipped with the following:

(1) A submerged fill pipe.

(2) Either a pressure relief valve set to release at no less than seven-tenths (0.7) pounds per square inch or an orifice of five-tenths (0.5) inch in diameter.

(b) If the owner or employees of the owner of a gasoline dispensing facility are not present during loading, it shall be the responsibility of the owner or the operator of the transport to make certain the vapor recovery system is connected between the transport and the storage tank and is operating according to manufacturer's specifications.

Compliance with this condition shall satisfy the requirements of 326 IAC 8-4-6.

D.6.6 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan (PMP) is required for the gasoline storage tanks (TK11), and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.6.7 Volatile Organic Compounds Control

In order to comply with Condition D.6.5, the Stage I vapor recovery systems for VOC control shall be in operation at all times when gasoline is being transferred.

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

D.6.8 Vapor Recovery System Operation

For the Stage I vapor recovery systems in order to document compliance with Condition D.6.5, the Permittee shall perform daily checks of the key operating parameters on days in which the filling of gasoline storage tanks is conducted, including venting for the Stage I vapor recovery system.

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

D.6.9 Record Keeping Requirements

(a) In order to document the compliance status with Conditions D.6.8 - Vapor Recovery System Operation, the Permittee shall maintain records of the key operating parameters when Stage 1 vapor recovery system is in use.

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

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: [326 IAC 2-7-5(14) **Insignificant Activities**

(l) Six (6) Electrical Circuit Breakers containing sulfur hexafluoride (SF_6) identified as emissions unit SF6, permitted in 2012, with fugitive GHG emissions.

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

Construction Conditions

General Construction Conditions

D.7.1 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 thereunder, as well as other applicable local, state, and federal requirements.

Effective Date of the Permit

D.7.2 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.7.3 Modification to Construction Conditions [326 IAC 2]

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

Operating Conditions

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

D.7.4 GHGs PSD BACT [326 IAC 2-2-3]

Pursuant to PSD/Operating Permit T 141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the six (6) Electrical Circuit Breakers, identified as SF6 shall be as follows:

(1) The use of a totally enclosed pressure system with a design leak rate of 0.5% and a density alarm for leak detection.

(2) The total SF_6 emissions from all the circuit breakers shall not exceed 0.0009 tons of SF_6 per twelve (12) consecutive month period with compliance determined at the end of the month.

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: [326 IAC 2-7-5(14) **Insignificant Activities**

(k) two (2) lime storage silos, capable of handling a maximum loading rate of 20 tons per hour combined, permitted in 2012 and with particulate matter controlled by bin vent filters exhausting to Stacks S1 and S2;

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

Construction Conditions

General Construction Conditions

D.8.1 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 thereunder, as well as other applicable local, state, and federal requirements.

Effective Date of the Permit

D.8.2 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.8.3 Modification to Construction Conditions [326 IAC 2]

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

Operating Conditions

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

D.8.4 Particulate Matter Limitations [326 IAC 6.5-1-2]

Pursuant to 326 IAC 6.5-1-2(a), the particulate emission from the lime silos shall not exceed 0.03 grains per dry standard cubic feet (gr/dscf) of exhaust air.

SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: [326 IAC 2-7-5(14) **Insignificant Activities**

(o) Degreasing operations that do not exceed one hundred forty-five (145) gallons per 12 months, except if subject to 326 IAC 20-6. [326 IAC 8-3];

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

Construction Conditions

General Construction Conditions

D.9.1 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 thereunder, as well as other applicable local, state, and federal requirements.

Effective Date of the Permit

D.9.2 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.9.3 Modification to Construction Conditions [326 IAC 2]

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

Operating Conditions

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

D.9.4 Volatile Organic Compounds (VOC) [326 IAC 8-3-2]

Pursuant to 326 IAC 8-3-2 (Cold Cleaner Operations), for cold cleaning operations constructed after January 1, 1980, the Permittee shall:

(a) Equip the cleaner with a cover;

(b) Equip the cleaner with a facility for draining cleaned parts;

(c) Close the degreaser cover whenever parts are not being handled in the cleaner;

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

(e) Provide a permanent, conspicuous label summarizing the operation requirements;

(f) Store waste solvent only in covered containers and not dispose of waste solvent or transfer it to another party, in such a manner that greater than twenty percent (20%) of the waste solvent (by weight) can evaporate into the atmosphere.

D.9.5 Volatile Organic Compounds (VOC) [326 IAC 8-3-5]

(a) Pursuant to 326 IAC 8-3-5(a) (Cold Cleaner Degreaser Operation and Control), for cold cleaner degreaser operations without remote solvent reservoirs constructed after July 1, 1990, the Permittee shall ensure that the following control equipment requirements are met:

(1) Equip the degreaser with a cover. The cover must be designed so that it can be easily operated with one (1) hand if:

(A) The solvent volatility is greater than two (2) kiloPascals (fifteen (15) millimeters of mercury or three-tenths (0.3) pounds per square inch) measured at thirty-eight degrees Celsius (38°C) (one hundred degrees Fahrenheit (100°F));

(B) The solvent is agitated; or

(C) The solvent is heated.

(2) Equip the degreaser with a facility for draining cleaned articles. If the solvent volatility is greater than four and three-tenths (4.3) kiloPascals (thirty-two (32) millimeters of mercury or six-tenths (0.6) pounds per square inch) measured at thirty-eight degrees Celsius (38°C) (one hundred degrees Fahrenheit (100°F)), then the drainage facility must be internal such that articles are enclosed under the cover while draining. The drainage facility may be external for applications where an internal type cannot fit into the cleaning system.

(3) Provide a permanent, conspicuous label which lists the operating requirements outlined in subsection (b).

(4) The solvent spray, if used, must be a solid, fluid stream and shall be applied at a pressure which does not cause excessive splashing.

(5) Equip the degreaser with one (1) of the following control devices if the solvent volatility is greater than four and three-tenths (4.3) kiloPascals (thirty-two (32) millimeters of mercury or six-tenths (0.6) pounds per square inch) measured at thirty-eight degrees Celsius (38°C) (one hundred degrees Fahrenheit (100°F)), or if the solvent is heated to a temperature greater than forty-eight and nine-tenths degrees Celsius (48.9°C) (one hundred twenty degrees Fahrenheit (120°F)):

(A) A freeboard that attains a freeboard ratio of seventy-five hundredths (0.75) or greater.

(B) A water cover when solvent is used is insoluble in, and heavier than, water.

(C) Other systems of demonstrated equivalent control such as a refrigerated chiller of carbon adsorption. Such systems shall be submitted to the U.S. EPA as a SIP revision.

(b) Pursuant to 326 IAC 8-3-5(b) (Cold Cleaner Degreaser Operation and Control), the owner or operator of a cold cleaning facility construction of which commenced after July 1, 1990, shall ensure that the following operating requirements are met:

(1) Close the cover whenever articles are not being handled in the degreaser.

(2) Drain cleaned articles for at least fifteen (15) seconds or until dripping ceases.

(3) Store waste solvent only in covered containers and prohibit the disposal or transfer of waste solvent in any manner in which greater than twenty percent (20%) of the waste solvent by weight could evaporate.

SECTION E.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) Four (4) natural gas-fired combined cycle combustion turbines, identified as units CCCT1, CCCT2, CCCT3, and CCCT4, permitted in 2012, each with a combustion turbine equipped with dry low NOx burners, natural gas fired duct burners, and a heat recovery steam generator identified as HRSG1, HRSG2, HRSG3, and HRSG4, NOx emissions controlled by four (4) selective catalytic reduction (SCR) systems (SCR01, SCR02, SCR03 and SCR04), CO and VOC emissions controlled by oxidation catalyst systems (CAT01, CAT02, CAT03 and CAT04) and exhausting to stacks CCCT01, CCCT02, CCCT03, and CCCT04, respectively. Each stack has continuous emissions monitors (CEMS) for NOx and CO. The nominal heat input for each CCCT is 2,300 MMBtu/hr (higher heating value (HHV)). The combined nominal power output is 1,350 megawatts (MW).

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

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

New Source Performance Standards (NSPS) Requirements [326 IAC 12][40 CFR 60, Subpart KKKK]

E.1.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart 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 four (4) natural gas combustion turbines CCCT1 through CCCT4 and four (4) duct burners associated with the heat recovery steam generators HRSG1 through HRSG4, except as otherwise specified in 40 CFR Part 60, Subparts KKKK.

E.1.2 New Source Performance Standards for Stationary Combustion Turbines Requirements [40 CFR Part 60, Subpart KKKK] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart KKKK, the Permittee shall comply with the provisions of New Source Performance Standards for Stationary Combustions Turbines, which are incorporated by reference as 326 IAC 12, for the four (4) natural gas combustion turbines CCCT1 through CCCT4 and four (4) duct burners associated with the heat recovery steam generators HRSG1 through HRSG4 as specified as follows:

1. 40 CFR 60.4300
2. 40 CFR 60.4305
3. 40 CFR 60.4320
4. 40 CFR 60.4330(a)(1) or (2)
5. 40 CFR 60.4333
6. 40 CFR 60.4340(b)(1)
7. 40 CFR 60.4345
8. 40 CFR 60.4350(a)-(e), (f)(1)(2), (h)
9. 40 CFR 60.4360

10. 40 CFR 60.4365
11. 40 CFR 60.4370(b), (c)
12. 40 CFR 60.4375(a)
13. 40 CFR 60.4380(b)
14. 40 CFR 60.4385(a), (c)
15. 40 CFR 60.4395
16. 40 CFR 60.4400(a), (b)(2), (b)(4)-(6)
17. 40 CFR 60.4405
18. 40 CFR 60.4415
19. 40 CFR 60.4420

SECTION E.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(b) Two (2) natural gas fired auxiliary boilers, identified as B001 and B002, permitted in 2012, each, with a maximum heat input capacity of 80 MMBtu/hr (HHV), equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stacks B001 and B002. Under 40 CFR Part 60, Subpart Dc, the auxiliary boiler is considered a 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 12][40 CFR 60, Subpart Dc]

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 natural gas fired auxiliary boiler, except as otherwise specified in 40 CFR Part 60, Subpart Dc.

E.2.2 New Source Performance Standards for Small-Commercial-Institutional Steam Generating Units Requirements [40 CFR Part 60, Subpart Dc] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart Dc, the Permittee shall comply with the provisions of New Source Performance Standards for Small-Commercial-Institutional Steam Generating Units, which are incorporated by reference as 326 IAC 12, for the natural gas fired auxiliary boiler as specified as follows:

1. 40 CFR 60.40c(a)-(d)
2. 40 CFR 60.41c
3. 40 CFR 60.48c(a)(1), (3)
4. 40 CFR 60.48c(g),(i)

SECTION E.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) Two (2) firewater pump engines, each nominally rated at 371 brake horsepower (bph)and identified as FP01 and FP02, permitted in 2012, exhausting through two (2) vents, identified as FP01 and FP02, respectively. [Under 40 CFR 60, Subpart IIII, the firewater pump engines are considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the firewater pump engines are considered new affected sources.]

(b) Two (2) emergency diesel generators, each nominally rated at 1,006 horsepower, identified as EG01 and EG02, permitted in 2012, exhausting through two (2) vents, identified as EG01 and EG02, respectively. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generators are considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generators are considered new affected source.]

(c) One (1) emergency diesel generator, nominally rated at 2012 horsepower, identified as EG03, permitted in 2012, exhausting through one (1) vent, identified as EG03. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generator is considered a new affected source.]

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

New Source Performance Standards [326 IAC 12] [40 CFR 60, Subpart IIII]

E.3.1 General Provisions Relating to NSPS IIII [326 IAC 12][40 CFR Part 60, Subpart A]

The provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to the emergency diesel generators and the firewater pump diesel engines described in this section except when otherwise specified in 40 CFR Part 60, Subpart IIII.

E.3.2 Standards of Performance for Stationary Compression Ingnition Internal Combustion Engines [326 IAC 12][40 CFR Part 60, Subpart IIII]

The Permittee who owns and operates stationary compression ignition (CI) internal combustion engines (ICE) shall comply with the following provisions of 40 CFR Part 60, Subpart IIII, included as Attachment C of this permit. The source is subject to the following portions of Subpart IIII:

The firewater pump engines are subject to the following Sections of 40 CFR Part 60, Subpart IIII.

1. 40 CFR 60.4200(a)(2)(ii)
2. 40 CFR 60.4205(c)
3. 40 CFR 60.4206
4. 401 CFR 60.4207
5. 40 CFR 60.4211(a), (c)
6. 40 CFR 60.4218
7. 401 CFR 60.4219

The emergency diesel generators are subject to the following Sections of 40 CFR Part 60, Subpart IIII.

1. 40 CFR 60.4200(a)(2)(i)
2. 40 CFR 60.4205(b)
3. 40 CFR 60.4206
4. 401 CFR 60.4207
5. 40 CFR 60.4211(a), (c)
6. 40 CFR 60.4218
7. 401 CFR 60.4219

SECTION E.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(b) Two (2) emergency diesel generators, each nominally rated at 1,006 horsepower, identified as EG01 and EG02, permitted in 2012, exhausting through two (2) vents, identified as EG01 and EG02, respectively. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generators are considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generators are considered new affected source.]

(c) One (1) emergency diesel generator, nominally rated at 2012 horsepower, identified as EG03, permitted in 2012, exhausting through one (1) vent, identified as EG03. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generator is considered a new affected source.]

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

National Emissions Standard for Hazardous Air Pollutants [326 IAC 20] [40 CFR 63, Subpart ZZZZ]

E.4.1 General Provisions Relating to National Emissions Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [326 IAC 20-1][40 CFR Part 63, Subpart A]

Pursuant to 40 CFR 63.6590, the Permittee shall comply with the provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1 for the affected source, as specified in Appendix A of 40 CFR Part 63, Subpart ZZZZ, in accordance with the schedule in 40 CFR 63 Subpart ZZZZ.

E.4.2 National Emissions Standard for Hazardous Air Pollutants for stationary Reciprocating Internal Combustion Engines [40 CFR Part 63, Subpart ZZZZ][326 IAC 20-82-1]

Pursuant to CFR Part 63, Subpart ZZZZ, the Permittee shall comply with the provisions of 40 CFR Part 63.6590, for the affected source, as specified as follows:

1. 40 CFR 63.6580
2. 40 CFR 63.6585(a), (c)-(d)
3. 40 CFR 63.6590(a)(2)(iii)
4. 40 CFR 63.6590(c)(1)
5. 40 CFR 63.6665
6. 40 CFR 63.6670
7. 40 CFR 63.6675

SECTION F Clean Air Interstate (CAIR) Nitrogen Oxides Annual, Sulfur Dioxide, and Nitrogen Oxides Ozone Season Trading Programs – CAIR Permit for CAIR Units Under 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a)

Emissions Unit Description:

(a) Four (4) natural gas-fired combined cycle combustion turbines, identified as units CCCT1, CCCT2, CCCT3, and CCCT4, permitted in 2012, each with a combustion turbine equipped with dry low NOx burners, natural gas fired duct burners, and a heat recovery steam generator identified as HRSG1, HRSG2, HRSG3, and HRSG4, NOx emissions controlled by four (4) selective catalytic reduction (SCR) systems (SCR01, SCR02, SCR03 and SCR04), CO and VOC emissions controlled by oxidation catalyst systems (CAT01, CAT02, CAT03 and CAT04) and exhausting to stacks CCCT01, CCCT02, CCCT03, and CCCT04, respectively. Each stack has continuous emissions monitors (CEMS) for NOx and CO. The nominal heat input for each CCCT is 2,300 MMBtu/hr (higher heating value (HHV)). The combined nominal power output is 1,350 megawatts (MW).

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

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

F.1 Automatic Incorporation of Definitions [326 IAC 24-1-7(e)] [326 IAC 24-2-7(e)] [326 IAC 24-3-7(e)] [40 CFR 97.123(b)] [40 CFR 97.223(b)] [40 CFR 97.323(b)]

This CAIR permit is deemed to incorporate automatically the definitions of terms under 326 IAC 24-1-2, 326 IAC 24-2-2, and 326 IAC 24-3-2.

F.2 Standard Permit Requirements [326 IAC 24-1-4(a)] [326 IAC 24-2-4(a)] [326 IAC 24-3-4(a)] [40 CFR 97.106(a)] [40 CFR 97.206(a)] [40 CFR 97.306(a)]

(a) The owners and operators of the CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and CAIR NO_X units, CAIR SO_2 unit(s), and CAIR NO_X ozone season units shall operate each unit in compliance with this CAIR permit.

(b) The CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X ozone season units subject to this CAIR permit are units CCCT1, CCCT2, CCCT3, and CCCT4.

F.3 Monitoring, Reporting, and Record Keeping Requirements [326 IAC 24-1-4(b)] [326 IAC 24-2-4(b)] [326 IAC 24-3-4(b)] [40 CFR 97.106(b)] [40 CFR 97.206(b)] [40 CFR 97.306(b)]

(a) The owners and operators, and the CAIR designated representative, of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source shall comply with the monitoring, reporting, and record keeping requirements of 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11.

(b) The emissions measurements recorded and reported in accordance with 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11 shall be used to determine compliance by each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source with the CAIR NO_X emissions limitation under 326 IAC 24-1-4(c), CAIR SO_2 emissions limitation under 326 IAC 24-2-4(c), and CAIR NO_X ozone season emissions limitation under 326 IAC 24-3-4(c) and Condition F.4.1, Nitrogen Oxides Emission Requirements, Condition F.4.2, Sulfur Dioxide Emission Requirements, and Condition F.4.3, Nitrogen Oxides Ozone Season Emission Requirements.

F.4.1 Nitrogen Oxides Emission Requirements [326 IAC 24-1-4(c)] [40 CFR 97.106(c)]

(a) As of the allowance transfer deadline, the owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall hold, in the source's compliance account, CAIR NO_X allowances available for compliance deductions for the control period under 326 IAC 24-1-9(i) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X units at the source, as determined in accordance with 326 IAC 24-1-11.

(b) A CAIR NO_X unit shall be subject to the requirements under (a) above for the control period starting on the later of January 1, 2009, or the deadline for meeting the unit's monitor certification requirements under section 326 IAC 24-1-11(c)(1), 11(c)(2), or 11(c)(5) and for each control period thereafter.

(c) A CAIR NO_X allowance shall not be deducted for compliance with the requirements under (a) above and 326 IAC 24-1-4(c)(1), for a control period in a calendar year before the year for which the CAIR NO_X allowance was allocated.

(d) CAIR NO_X allowances shall be held in, deducted from, or transferred into or among CAIR NO_X allowance tracking system accounts in accordance with 326 IAC 24-1-9, 326 IAC 24-1-10, and 326 IAC 24-1-12.

(e) A CAIR NO_X allowance is a limited authorization to emit one (1) ton of nitrogen oxides in accordance with the CAIR NO_X annual trading program. No provision of the CAIR NO_X annual trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-1-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR NO_X allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-1-8, 326 IAC 24-1-9, 326 IAC 24-1-10, or 326 IAC 24-1-12, every allocation, transfer, or deduction of a CAIR NO_X allowance to or from a CAIR NO_X source's compliance account is incorporated automatically in this CAIR permit.

F.4.2 Sulfur Dioxide Emission Requirements [326 IAC 24-2-4(c)] [40 CFR 97.206(c)]

(a) As of the allowance transfer deadline, the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, a tonnage equivalent of CAIR SO_2 allowances available for compliance deductions for the control period under 326 IAC 24-2-8(j) and 326 IAC 24-2-8(k) not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance with 326 IAC 24-2-10.

(b) A CAIR SO_2 unit shall be subject to the requirements under (a) above for the control period starting on the later of January 1, 2010 or the deadline for meeting the unit's monitor certification requirements under section 326 IAC 24-2-10(c)(1), 10(c)(2), or 10(c)(5) and for each control period thereafter.

(c) A CAIR SO_2 allowance shall not be deducted for compliance with the requirements under (a) above and 326 IAC 24-2-4(c)(1), for a control period in a calendar year before the year for which the CAIR SO_2 allowance was allocated.

(d) CAIR SO_2 allowances shall be held in, deducted from, or transferred into or among CAIR SO_2 allowance tracking system accounts in accordance with 326 IAC 24-2-8, 326 IAC 24-2-9, and 326 IAC 24-2-11.

(e) A CAIR SO_2 allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO_2 trading program. No provision of the CAIR SO_2 trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-2-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR SO_2 allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-2-8, 326 IAC 24-2-9, or 326 IAC 24-2-11, every allocation, transfer or deduction of a CAIR SO_2 allowance to or from a CAIR SO_2 source's compliance account is incorporated automatically in this CAIR permit.

F.4.3 Nitrogen Oxides Ozone Season Emission Requirements [326 IAC 24-3-4(c)] [40 CFR 97.306(c)]

(a) As of the allowance transfer deadline, the owners and operators of the each CAIR NO_X ozone season source and each CAIR NO_X ozone season unit at the source shall hold, in the source's compliance account, CAIR NO_X ozone season allowances available for compliance deductions for the control period under 326 IAC 24-3-9(i) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X ozone season units at the source, as determined in accordance with 326 IAC 24-3-11.

(b) A CAIR NO_X unit shall be subject to the requirements under (a) above for the control period starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under section 326 IAC 24-3-11(c)(1), 11(c)(2), 11(c)(3), or 11(c)(7) and for each control period thereafter.

(c) A CAIR NO_X ozone season allowance shall not be deducted for compliance with the requirements under (a) above and 326 IAC 24-3-4(c)(1), for a control period in a calendar year before the year for which the CAIR NO_X ozone season allowance was allocated.

(d) CAIR NO_X ozone season allowances shall be held in, deducted from, or transferred into or among CAIR NO_X ozone season allowance tracking system accounts in accordance with 326 IAC 24-3-9, 326 IAC 24-3-10, and 326 IAC 24-3-12.

(e) A CAIR NO_X allowance is a limited authorization to emit one (1) ton of nitrogen oxides in accordance with the CAIR NO_X ozone season trading program. No provision of the CAIR

NO_X ozone season trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-3-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR NO_X allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-3-8, 326 IAC 24-3-9, 326 IAC 24-3-10, or 326 IAC 24-3-12, every allocation, transfer, or deduction of a CAIR NO_X ozone season allowance to or from a CAIR NO_X ozone season source's compliance account is incorporated automatically in this CAIR permit.

F.5 Excess Emissions Requirements [326 IAC 24-1-4(d)] [326 IAC 24-2-4(d)] [326 IAC 24-3-4(d)] [40 CFR 97.106(d)] [40 CFR 97.206(d)] [40 CFR 97.306(d)]

The owners and operators of a CAIR NO_X source and each CAIR NO_X unit that emits nitrogen oxides during any control period in excess of the CAIR NO_X emissions limitation shall do the following:

(a) Surrender the CAIR NO_X allowances required for deduction under 326 IAC 24-1-9(j)(4).

(b) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-1-4, the Clean Air Act (CAA), and applicable state law.

The owners and operators of a CAIR SO_2 source and each CAIR SO_2 unit that emits sulfur dioxide during any control period in excess of the CAIR SO_2 emissions limitation shall do the following:

(a) Surrender the CAIR SO_2 allowances required for deduction under 326 IAC 24-2-8(k)(4).

(b) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-2-4, the Clean Air Act (CAA), and applicable state law.

The owners and operators of a CAIR NO_X ozone season source and each CAIR NO_X ozone season unit that emits nitrogen oxides during any control period in excess of the CAIR NO_X ozone season emissions limitation shall do the following:

(a) Surrender the CAIR NO_X ozone season allowances required for deduction under 326 IAC 24-3-9(j)(4).

(b) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-3-4, the Clean Air Act (CAA), and applicable state law.

F.6 Record Keeping Requirements [326 IAC 24-1-4(e)] [326 IAC 24-2-4(e)] [326 IAC 24-3-4(e)] [326 IAC 2-7-5(3)] [40 CFR 97.106(e)] [40 CFR 97.206(e)] [40 CFR 97.306(e)]

Unless otherwise provided, the owners and operators of the CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source shall keep on site at the source or at a central location within Indiana for those owners or operators with unattended sources, each of the following documents for a period of five (5) years from the date the document was created:

(a) The certificate of representation under 326 IAC 24-1-6(h), 326 IAC 24-2-6(h), 326 IAC 24-3-6(h) for the CAIR designated representative for the source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation. The certificate and documents shall be retained on site at the source or at a central location within Indiana for those owners or operators with unattended sources beyond such five (5) year period until such documents are superseded because of the submission of a new account certificate of representation under 326 IAC 24-1-6(h), 326 IAC 24-2-6(h), 326 IAC 24-3-6(h) changing the CAIR designated representative.

(b) All emissions monitoring information, in accordance with 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11, provided that to the extent that 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11 provides for a three (3) year period for record keeping, the three (3) year period shall apply.

(c) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program.

(d) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program or to demonstrate compliance with the requirements of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program.

This period may be extended for cause, at any time before the end of five (5) years, in writing by IDEM, OAQ or the U.S. EPA. Unless otherwise provided, all records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

F.7 Reporting Requirements [326 IAC 24-1-4(e)] [326 IAC 24-2-4(e)] [326 IAC 24-3-4(e)] [40 CFR 97.106(e)] [40 CFR 97.206(e)] [40 CFR 97.306(e)]

(a) The CAIR designated representative of the CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source shall submit the reports required under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program, including those under 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11.

(b) Pursuant to 326 IAC 24-1-4(e), 326 IAC 24-2-4(e), and 326 IAC 24-3-4(e) and 326 IAC 24-1-6(e)(1), 326 IAC 24-2-6(e)(1), and 326 IAC 24-3-6(e)(1), each submission under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone

season trading program shall include the following certification statement by the CAIR designated representative: “I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(c) Where 326 IAC 24-1, 326 IAC 24-2, and 326 IAC 24-3 requires a submission to IDEM, OAQ, the CAIR designated representative shall submit required information to:

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

(d) Where 326 IAC 24-1, 326 IAC 24-2, and 326 IAC 24-3 requires a submission to U.S. EPA, the CAIR designated representative shall submit required information to:

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue, NW
Mail Code 6204N
Washington, DC 20460

F.8 Liability [326 IAC 24-1-4(f)] [326 IAC 24-2-4(f)] [326 IAC 24-3-4(f)] [40 CFR 97.106(f)] [40 CFR 97.206(f)] [40 CFR 97.306(f)]

The owners and operators of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall be liable as follows:

(a) Each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall meet the requirements of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program.

(b) Any provision of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program that applies to a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source or the CAIR designated representative of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source shall also apply to the owners and operators of such source and of the CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X ozone season units at the source

(c) Any provision of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program that applies to a CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit or the CAIR designated representative of a CAIR

NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall also apply to the owners and operators of such units.

F.9 Effect on Other Authorities [326 IAC 24-1-4(g)] [326 IAC 24-2-4(g)] [326 IAC 24-3-4(g)] [40 CFR 97.106(g)] [40 CFR 97.206(g)] [40 CFR 97.306(g)]

No provision of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program, a CAIR permit application, a CAIR permit, or an exemption under 326 IAC 24-1-3, 326 IAC 24-2-3, and 326 IAC 24-3-3 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source or CAIR NO_X unit(s), CAIR SO_2 unit(s), and CAIR NO_X ozone season unit(s) from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act (CAA).

F.10 CAIR Designated Representative and Alternate CAIR Designated Representative [326 IAC 24-1-6] [326 IAC 24-2-6] [326 IAC 24-3-6] [40 CFR 97, Subpart BB] [40 CFR 97, Subpart BBB] [40 CFR 97, Subpart BBBB]

Pursuant to 326 IAC 24-1-6, 326 IAC 24-2-6, and 326 IAC 24-3-6:

(a) Except as specified in 326 IAC 24-1-6(f)(3), 326 IAC 24-2-6(f)(3), and 326 IAC 24-3-6(f)(3), each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source, including all CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X ozone season units at the source, shall have one (1) and only one (1) CAIR designated representative, with regard to all matters under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program concerning the source or any CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source.

(b) The provisions of 326 IAC 24-1-6(f), 326 IAC 24-2-6(f), and 326 IAC 24-3-6(f) shall apply where the owners or operators of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source choose to designate an alternate CAIR designated representative.

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

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579

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

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☐ Test Result (specify)

☐ Report (specify)

☐ Notification (specify)

☐ Affidavit (specify)

☐ Other (specify)

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature:
Printed Name:
Title/Position:
Phone:
Date:

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

PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579

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

☐ This is an emergency as defined in 326 IAC 2-7-1(12)

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

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

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

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

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

Form Completed by:_____
Title / Position: _____
Date:_____
Phone: _____

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combined Cycle Combustion Turbine CCCT1
Parameter: NOx Emissions
Limit: shall not exceed 81.6 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.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combined Cycle Combustion TurbineCCCT2
Parameter: NOx Emissions
Limit: shall not exceed 81.6 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.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combined Cycle Combustion TurbineCCCT3
Parameter: NOx Emissions
Limit: shall not exceed 81.6 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.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combined Cycle Combustion TurbineCCCT4
Parameter: NOx Emissions
Limit: shall not exceed 81.6 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.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combined Cycle Combustion TurbineCCCT1
Parameter: CO Emissions
Limit: shall not exceed 407.5 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.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combined Cycle Combustion TurbineCCCT2
Parameter: CO Emissions
Limit: shall not exceed 407.5 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.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combined Cycle Combustion Turbine CCCT3
Parameter: CO Emissions
Limit: shall not exceed 407.5 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.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combined Cycle Combustion Turbine CCCT4
Parameter: CO Emissions
Limit: shall not exceed 407.5 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.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combustion Turbine CCCT1
Parameter: VOC Emissions
Limit: shall not exceed 22.0 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combustion Turbine CCCT2
Parameter: VOC Emissions
Limit: shall not exceed 22.0 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combustion Turbine CCCT3
Parameter: VOC Emissions
Limit: shall not exceed 22.0 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combustion Turbine CCCT4
Parameter: VOC Emissions
Limit: shall not exceed 22.0 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combined Cycle Combustion Turbine CCCT1
Parameter: Hours of Operation
Limit: shall not exceed 365.0 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.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combined Cycle Combustion Turbine CCCT2
Parameter: Hours of Operation
Limit: shall not exceed 365.0 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.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combined Cycle Combustion Turbine CCCT3
Parameter: Hours of Operation
Limit: shall not exceed 365.0 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.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combined Cycle Combustion Turbine CCCT4
Parameter: Hours of Operation
Limit: shall not exceed 365.0 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.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Firewater Pump Engines FP01
Parameter: Hours of Operation
Limit: shall not exceed 500 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Firewater Pump Engines FP02
Parameter: Hours of Operation
Limit: shall not exceed 500 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Emergency Diesel Generator EG01
Parameter: Hours of Operation
Limit: shall not exceed 500 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Emergency Diesel Generator EG02
Parameter: Hours of Operation
Limit: shall not exceed 500 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Emergency Diesel Generator EG03
Parameter: Hours of Operation
Limit: shall not exceed 500 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Combined Cycle Combustion Turbine CCCT1 - CCCT4
Parameter: CO2e
Limit: shall not exceed 4,885,512 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Auxiliary Boilers B001-B002
Parameter: CO2e
Limit: shall not exceed 81,996 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Emergency Generator EG01 -EG03
Parameter: CO2e
Limit: shall not exceed 1,186 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

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

Part 70 Quarterly Report

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579
Facility: Firewater Pumps FP01-FP02
Parameter: Hours of Operation
Limit: shall not exceed 172 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

QUARTER : YEAR:

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

☐ No deviation occurred in this quarter.

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

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

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY

COMPLIANCE AND ENFORCEMENT BRANCH

PART 70 OPERATING PERMIT

QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: St. Joseph Energy Center, LLC
Source Address: Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552
Part 70 Permit No.: T141-31003-00579

Months: _____ to _____ Year: _____

This report shall be submitted quarterly based on a calendar year. 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
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

St. Joseph Energy Center, LLC
Corner of Walnut and Edison Roads
New Carlisle, Indiana 46552

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 St. Joseph Energy Center, LLC Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552, completed construction of the electric utility generating station on _____in conformity with the requirements and intent of the construction permit application received by the Office of Air Quality on ***Reviewer: Insert date application received at IDEM*** and as permitted pursuant to New Source Construction Permit and Part 70 Operating Permit No. T141-31003-00579, Plant ID No. 141-00579 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)

Attachment A to a PSD/Part 70 Operating Permit

Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units [40 CFR Part 60, Subpart Dc] [326 IAC 12]

Source Name:	**St. Joseph Energy Center, LLC**
Source Location:	**Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552**
County:	**St. Joseph**
SIC Code:	**4911**
Operation Permit No.:	**T 141-31003-00579**
Operation Permit Issuance Date:	**Yet to be issued**
Permit Reviewer:	**Josiah Balogun**

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Source: 72 FR 32759, June 13, 2007, unless otherwise noted.

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in §60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under §60.14.

(e) Heat recovery steam generators that are associated with combined cycle gas turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/hr) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(f) Any facility covered by subpart AAAA of this part is not subject by this subpart.

(g) Any facility covered by an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject by this subpart.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

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

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Cogeneration steam generating unit means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (*i.e.* , the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17) or diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO_2control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO_2control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under §60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO_2emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Wet flue gas desulfurization technology means an SO_2control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

§ 60.42c Standard for sulfur dioxide (SO_2).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO_2emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of SO_2in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO_2emissions limit or the 90 percent SO_2reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO_2emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of 50 percent (0.50) of the potential SO_2emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent

SO_2reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/hr) or less.

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area.

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of 215 ng/J (0.50 lb/MMBtu) heat input; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2in excess of the following:

(1) The percent of potential SO_2emission rate or numerical SO_2emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/hr); and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$$

Where:

E_s= SO_2emission limit, expressed in ng/J or lb/MMBtu heat input;

K_a= 520 ng/J (1.2 lb/MMBtu);

K_b= 260 ng/J (0.60 lb/MMBtu);

K_c= 215 ng/J (0.50 lb/MMBtu);

H_a= Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

H_b= Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

H_c= Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential SO_2emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO_2emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO_2control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), or (3) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under §60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(i) The SO_2emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]

§ 60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that can combust coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph.

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50

weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under §60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO_2emissions is not subject to the PM limit in this section.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and §60.8(b), performance tests required under §60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under §60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO_2emission limits under §60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) of this section and §60.8, compliance with the percent reduction requirements and SO_2emission limits under §60.42c is based on the average percent reduction and the average SO_2emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO_2emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO_2emission rate (E_{ho}) and the 30-day average SO_2emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate $E_{ao}$when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted E_{ho}(E_{ho}o) is used in Equation 19–19 of Method 19 of appendix A of this part to compute the adjusted E_{ao}(E_{ao}o). The E_{ho}o is computed using the following formula:

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

Where:

E_{ho}o = Adjusted E_{ho}, ng/J (lb/MMBtu);

E_{ho}= Hourly SO_2emission rate, ng/J (lb/MMBtu);

E_w= SO_2concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value $E_w$for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure $E_w$if the owner or operator elects to assume E_w= 0.

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

(2) The owner or operator of an affected facility that qualifies under the provisions of §60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters $E_w$or $X_k$if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(f) Affected facilities subject to the percent reduction requirements under §60.42c(a) or (b) shall determine compliance with the SO_2emission limits under §60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO_2emission rate is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:

$\%P_s$= Potential SO_2emission rate, in percent;

$\%R_g$= SO_2removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$= SO_2removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the $\%P_s$, an adjusted $\%R_g$($\%R_g$o) is computed from E_{ao}o from paragraph (e)(1) of this section and an adjusted average SO_2inlet rate (E_{ai}o) using the following formula:

$$\%R_g o = 100\left(1 - \frac{E_{ao}^{\circ}}{E_{ai}^{\circ}}\right)$$

Where:

$\%R_g$o = Adjusted $\%R_g$, in percent;

E_{ao}o = Adjusted E_{ao}, ng/J (lb/MMBtu); and

E_{ai}o = Adjusted average SO_2inlet rate, ng/J (lb/MMBtu).

(ii) To compute E_{ai}o, an adjusted hourly SO_2inlet rate (E_{hi}o) is used. The E_{hi}o is computed using the following formula:

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

Where:

$E_{hi}o$ = Adjusted E_{hi}, ng/J (lb/MMBtu);

E_{hi}= Hourly SO_2inlet rate, ng/J (lb/MMBtu);

E_w= SO_2concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value $E_w$for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure $E_w$if the owner or operator elects to assume E_w= 0; and

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

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under §60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under §60.46c(d)(2).

(h) For affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in §60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2standards under §60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO_2emissions data in calculating $\%P_s$and E_{ho}under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under §60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating $\%P_s$or E_{ho}pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under §60.43c shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B of appendix A–2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A–3 of this part or 17 of appendix A–6 of this part.

(3) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F).

(6) For determination of PM emissions, an oxygen (O_2) or carbon dioxide (CO_2) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O_2or CO_2measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(8) Method 9 of appendix A–4 of this part shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under §60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) In place of PM testing with Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (c)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (c)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (c)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2(or CO_2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A–3 of this part or Method 17 of appendix A–6 of this part shall be used; and

(ii) For O2 (or CO_2), Method 3A or 3B of appendix A–2 of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

(14) After July 1, 2011, within 90 days after the date of completing each performance evaluation required by paragraph (c)(11) of this section, the owner or operator of the affected facility must either submit the test data to EPA by successfully entering the data electronically into EPA's WebFIRE data base available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main* or mail a copy to: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; Mail Code: D243–01; RTP, NC 27711.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under §60.43c(e)(4) shall follow the applicable procedures under §60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/hr).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011]

§ 60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO_2emission limits under §60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2concentrations and either O_2or CO_2concentrations at the outlet of the SO_2control device (or the outlet of the steam generating unit if no SO_2control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under §60.42c shall measure SO_2concentrations and either O_2or CO_2concentrations at both the inlet and outlet of the SO_2control device.

(b) The 1-hour average SO_2emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average SO_2emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under §60.13(h)(2). Hourly SO_2emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities subject to the percent reduction requirements under §60.42c, the span value of the SO_2CEMS at the inlet to the SO_2control device shall be 125 percent of the maximum estimated hourly potential SO_2emission rate of the fuel combusted, and the span value of the SO_2CEMS at the outlet from the SO_2control device shall be 50 percent of the maximum estimated hourly potential SO_2emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c, the span value of the SO_2CEMS at the outlet from the SO_2control device (or outlet of the steam generating unit if no SO_2control device is used) shall be 125 percent of the maximum estimated hourly potential SO_2emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO_2control device (or outlet of the steam generating unit if no SO_2control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO_2control device (or outlet of the steam generating unit if no SO_2control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO_2at the inlet or outlet of the SO_2control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable $SO_2$and CO_2measurement train operated at the candidate location and a second similar train operated according to the procedures in §3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this

part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2standards based on fuel supplier certification, as described under §60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), (f), and (g) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under §60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in §60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A–4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A–7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A–7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A–4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in §60.45c(a)(8).

(ii) If no visible emissions are observed for 30 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS “Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.” This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO2 or PM emissions and that are subject to an opacity standard in §60.43c(c) are not required to operate a COMS if they follow the applicable procedures in §60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in §60.45c(c). The CEMS specified in paragraph §60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(4) You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(f) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most recent requirements in section §60.48Da of this part is not required to operate a COMS.

(g) Owners and operators of an affected facility that is subject to an opacity standard in §60.43c(c) and that burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011]

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2emission limits of §60.42c, or the PM or opacity limits of §60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in §60.7, the owner or operator of an affected facility subject to the opacity limits in §60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator

(d) The owner or operator of each affected facility subject to the SO_2emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO_2emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO_2emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO_2emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO_2or diluent (O_2or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO_2standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO_2standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c or §60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

Attachment B to a PSD/Part 70 Operating Permit

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

Source Name:	**St. Joseph Energy Center, LLC**
Source Location:	**Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552**
County:	**St. Joseph**
SIC Code:	**4911**
Operation Permit No.:	**T 141-31003-00579**
Operation Permit Issuance Date:	**Yet to be issued**
Permit Reviewer:	**Josiah Balogun**

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

What This Subpart Covers

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (3) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines,

(ii) The model year listed in table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are:

(i) Manufactured after April 1, 2006 and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of stationary CI ICE that modify or reconstruct their stationary CI ICE after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart.

Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

Emission Standards for Manufacturers

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power.

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power.

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

§ 60.4203 How long must my engines meet the emission standards if I am a stationary CI internal combustion engine manufacturer?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the useful life of the engines.

Emission Standards for Owners and Operators

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (c)(1) and (2) of this section.

(1) Reduce nitrogen oxides (NO_X) emissions by 90 percent or more, or limit the emissions of NO_Xin the stationary CI internal combustion engine exhaust to 1.6 grams per KW-hour (g/KW-hr) (1.2 grams per HP-hour (g/HP-hr)).

(2) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (d)(1) and (2) of this section.

(1) Reduce NO_Xemissions by 90 percent or more, or limit the emissions of NO_Xin the stationary CI internal combustion engine exhaust to 1.6 grams per KW-hour (1.2 grams per HP-hour).

(2) Reduce PM emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

(c) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart may petition the Administrator for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of this section beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(d) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the Federal Aid Highway System may petition the Administrator for approval to use any fuels mixed with used lubricating oil that do not meet the fuel requirements of paragraphs (a) and (b) of this section. Owners and operators must demonstrate in their petition to the Administrator that there is no other place to use the lubricating oil. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

Other Requirements for Owners and Operators

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in the previous model year?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (f) of this section after the dates specified in paragraphs (a) through (f) of this section.

(h) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Compliance Requirements

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and §60.4202(c) using the certification procedures required in 40 CFR part 94 subpart C, and must test their engines as specified in 40 CFR part 94.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 40 CFR 1039.125, 40 CFR 1039.130, 40 CFR 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89 or 40 CFR part 94 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in part 89, 94 or 1039, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in part 89, 94 or 1039, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under parts 89, 94, or 1039 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as “Fire Pump Applications Only”.

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and $NO_X$and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit $NO_X$and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under §60.4205 but not §60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited.

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (d) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \qquad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (d) of this section.

(a) Each performance test must be conducted according to the requirements in §60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

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

Where:

C_i= concentration of NO_Xor PM at the control device inlet,

C_o= concentration of NO_Xor PM at the control device outlet, and

R = percent reduction of NO_Xor PM emissions.

(2) You must normalize the NO_Xor PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \% O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj}= Calculated NO_Xor PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_Xor PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2correction value, percent.

$\%O_2$= Measured O_2concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent $O_2$and CO_2concentration is measured in lieu of O_2concentration measurement, a CO_2correction factor is needed. Calculate the CO_2correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific $F_o$value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209 F_d}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o= Fuel factor based on the ratio of O_2volume to the ultimate CO_2volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d= Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

F_c= Ratio of the volume of CO_2produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

(ii) Calculate the CO_2correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2}= CO_2correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2correction value, percent.

(iii) Calculate the $NO_X$and PM gas concentrations adjusted to 15 percent O_2using CO_2as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj}= Calculated NO_Xor PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_Xor PM, uncorrected.

$\%CO_2$= Measured CO_2concentration, dry basis, percent.

(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_X concentration in ppm.

1.912×10^{-3} = Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

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

T = Time of test run, in hours.

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

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

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

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

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

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

Notification, Reports, and Records for Owners and Operators

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

Special Requirements

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §60.4205. Non-emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder, must meet the applicable emission standards in §60.4204(c).

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in §60.4207.

§ 60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI engines located in areas of Alaska not accessible by the Federal Aid Highway System should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) The Governor of Alaska may submit for EPA approval, by no later than January 11, 2008, an alternative plan for implementing the requirements of 40 CFR part 60, subpart IIII, for public-sector electrical utilities located in rural areas of Alaska not accessible by the Federal Aid Highway System. This alternative plan must be based on the requirements of section 111 of the Clean Air Act including any increased risks to human health and the environment and must also be based on the unique circumstances related to remote power generation, climatic conditions, and serious economic impacts resulting from implementation of 40 CFR part 60, subpart IIII. If EPA approves by rulemaking process an alternative plan, the provisions as approved by EPA under that plan shall apply to the diesel engines used in new stationary internal combustion engines subject to this paragraph.

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

(a) Owners and operators of stationary CI ICE that do not use diesel fuel, or who have been given authority by the Administrator under §60.4207(d) of this subpart to use fuels that do not meet the fuel requirements of paragraphs (a) and (b) of §60.4207, may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4202 or §60.4203 using such fuels.

(b) [Reserved]

General Provisions

§ 60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Definitions

§ 60.4219 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the CAA and in subpart A of this part.

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary CI ICE used to supply power to an

electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines.

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means either:

(1) The calendar year in which the engine was originally produced, or

(2) The annual new model production period of the engine manufacturer if it is different than the calendar year. This must include January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year. For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was originally produced.

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

Useful life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for useful life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for useful life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder

and 2007–2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)

	Model year(s)	NO_X+ NMHC	CO	PM
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

[As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:]

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)

56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+[2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		0.20 (0.15)

[1]For model years 2011–2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2]For model years 2010–2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3]In model years 2009–2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed[1]	Torque (percent)[2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1]Engine speed: ±2 percent of point.

[2]Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

[As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:]

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥30 liters per cylinder	a. Reduce NO_X emissions by 90 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_X concentration.

			§60.17)	
		iv. Measure NO_X at the inlet and outlet of the control device	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and,	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.
		iv. Measure NO_X at the exhaust of the stationary internal combustion engine	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

			by reference, see §60.17)	
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary,	(3) Method 4 of	(c) Measurements to

		measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	40 CFR part 60, appendix A	determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in §60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards	No	Requirements are specified in subpart IIII.

	and maintenance requirements		
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

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Attachment C to a PSD/Part 70 Operating Permit

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

Source Name:	**St. Joseph Energy Center, LLC**
Source Location:	**Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552**
County:	**St. Joseph**
SIC Code:	**4911**
Operation Permit No.:	**T 141-31003-00579**
Operation Permit Issuance Date:	**Yet to be issued**
Permit Reviewer:	**Josiah Balogun**

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

Source: 71 FR 38497, July 6, 2006, unless otherwise noted.

Introduction

§ 60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Applicability

§ 60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

§ 60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in §60.4420(i), are exempt from the nitrogen oxides (NO_X) emission limits in §60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NO_Xemission limits in §60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

Emission Limits

§ 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_X) and sulfur dioxide (SO_2).

§ 60.4320 What emission limits must I meet for nitrogen oxides (NOX)?

(a) You must meet the emission limits for NO_Xspecified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X.

§ 60.4325 What emission limits must I meet for NOX if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

§ 60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or

(3) For each stationary combustion turbine burning at least 50 percent biogas on a calendar month basis, as determined based on total heat input, you must not cause to be discharged into the atmosphere from the affected source any gases that contain SO_2in excess of 65 ng SO_2/J (0.15 lb SO_2/MMBtu) heat input.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

General Compliance Requirements

§ 60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NO_Xemissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

Monitoring

§ 60.4335 How do I demonstrate compliance for NOXif I use water or steam injection?

(a) If you are using water or steam injection to control NO_Xemissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_Xmonitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_Xemission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

§ 60.4340 How do I demonstrate continuous compliance for NOXif I do not

use water or steam injection?

(a) If you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO_X formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.

(iii) For any turbine that uses SCR to reduce NO_X emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H).

§ 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NO_X CEMS is chosen:

(a) Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

§ 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_x)_h * (HI)_h}{P} \qquad \text{(Eq. 1)}$$

Where:

E = hourly NO_X emission rate, in lb/MWh,

$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu,

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), *e.g.* , calculated using Equation D–15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output

that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad (Eq. 2)$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

$(Pe)_t$= electrical or mechanical energy output of the combustion turbine in MW,

$(Pe)_c$= electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \qquad (Eq. 3)$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 x 10_6= conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_x)_m}{BL * AL} \qquad (Eq. 4)$$

Where:

E = NO_Xemission rate in lb/MWh,

$(NO_X)_m$= NO_Xemission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in §60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).

§ 60.4355 How do I establish and document a proper parameter monitoring plan?

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_Xemission controls. The plan must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NO_Xemission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in §75.19 or the NO_Xemission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in §75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

§ 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

§ 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

§ 60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.* , flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

Reporting

§ 60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

§ 60.4380 How are excess emissions and monitor downtime defined for

NOX?

For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) For turbines using water or steam to fuel ratio monitoring:

(1) An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.4320, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NO_Xcontrol will also be considered an excess emission.

(2) A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_Xemission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a “4-hour rolling average NO_Xemission rate” is the arithmetic average of the average NO_Xemission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_Xemission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_Xemission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a “30-day rolling average NO_Xemission rate” is the arithmetic average of all hourly NO_Xemission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_Xemissions rates for the preceding 30 unit operating days if a valid NO_Xemission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_Xconcentration, CO2 or O_2concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NO_Xemission controls:

(1) An excess emission is a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(2) A period of monitor downtime is a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

§ 60.4385 How are excess emissions and monitoring downtime defined for SO_2?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

§ 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

(a) If you operate an emergency combustion turbine, you are exempt from the NO_Xlimit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NO_Xlimit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

§ 60.4395 When must I submit my reports?

All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

Performance Tests

§ 60.4400 How do I conduct the initial and subsequent performance tests, regarding NOX?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent NO_Xperformance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO_Xconcentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_Xemission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \qquad \text{(Eq. 5)}$$

Where:

E = NO_Xemission rate, in lb/MWh

1.194×10^{-7}= conversion constant, in lb/dscf-ppm

$(NO_X)_c$= average NO_Xconcentration for the run, in ppm

Q_{std}= stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(ii) Measure the $NO_X$and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO_Xemission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NO_Xemission rate in lb/MWh.

(2) Sampling traverse points for $NO_X$and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

(i) You may perform a stratification test for $NO_X$and diluent pursuant to

(A) [Reserved], or

(B) The procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.

(ii) Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_Xconcentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2(or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_Xconcentration during the stratification test; or

(B) For turbines with a NO_Xstandard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_Xconcentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO_2(or O_2) from the mean for all traverse points; or

(C) For turbines with a NO_Xstandard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_Xconcentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2(or O_2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be

achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_Xemissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control $NO_X$with no additional post-combustion NO_Xcontrol and you choose to monitor the steam or water to fuel ratio in accordance with §60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.4320 NO_Xemission limit.

(4) Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_Xemission rate at each tested level meets the applicable emission limit in §60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0 °F during the performance test.

§ 60.4405 How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS?

If you elect to install and certify a NO_X-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NO_Xemission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.

(d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NO_Xemission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

§ 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NO_Xemission controls in accordance with §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.4355.

§ 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent SO_2performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

(2) Measure the SO_2concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO_2emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \qquad \text{(Eq. 6)}$$

Where:

E = SO_2emission rate, in lb/MWh

1.664×10^{-7}= conversion constant, in lb/dscf-ppm

$(SO_2)_c$= average SO_2concentration for the run, in ppm

Q_{std}= stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

(3) Measure the $SO_2$and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO_2emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO_2emission rate in lb/MWh.

(b) [Reserved]

Definitions

§ 60.4420 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

Biogas means gas produced by the anaerobic digestion or fermentation of organic matter including manure, sewage sludge, municipal solid waste, biodegradable waste, or any other biodegradable feedstock, under anaerobic conditions. Biogas is comprised primarily of methane and CO_2.

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output—based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NO_Xemissions are higher than the applicable emission limit in §60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.4330; or (3) the recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore platforms.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

Regenerative cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine.

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

[71 FR 38497, July 6, 2006, as amended at 74 FR 11861, Mar. 20, 2009]

Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for

New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing natural gas, electric generating	≤ 50 MMBtu/h	42 ppm at 15 percent O_2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O_2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating	≤ 50 MMBtu/h	96 ppm at 15 percent O_2 or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O_2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850	96 ppm at 15 percent O_2 or 590 ng/J of useful

	MMBtu/h	output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	≤ 30 MW output	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0 °F	> 30 MW output	96 ppm at 15 percent O_2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

Attachment D to a PSD/Part 70 Operating Permit

40 CFR 63, Subpart ZZZZ—National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines:

Source Name:	**St. Joseph Energy Center, LLC**
Source Location:	**Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552**
County:	**St. Joseph**
SIC Code:	**4911**
Operation Permit No.:	**T 141-31003-00579**
Operation Permit Issuance Date:	**Yet to be issued**
Permit Reviewer:	**Josiah Balogun**

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Source: 69 FR 33506, June 15, 2004, unless otherwise noted.

What This Subpart Covers

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a

reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008]

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(vi) Existing residential emergency stationary RICE located at an area source of HAP emissions;

(vii) Existing commercial emergency stationary RICE located at an area source of HAP emissions; or

(viii) Existing institutional emergency stationary RICE located at an area source of HAP emissions.

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010]

§ 63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

Emission and Operating Limitations

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§ 63.6602 What emission limitations must I meet if I own or operate an

existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

[75 FR 51589, Aug. 20, 2010]

§ 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 1b and Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by the Federal Aid Highway System (FAHS) you do not have to meet the numerical CO emission limitations specified in Table 2d to this subpart. Existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by the FAHS must meet the management practices that are shown for stationary non-emergency CI RICE less than or equal to 300 HP in Table 2d to this subpart.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011]

§ 63.6604 What fuel requirements must I meet if I own or operate an existing stationary CI RICE?

If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel. Existing non-emergency CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, or at area sources in areas of Alaska not accessible by the FAHS are exempt from the requirements of this section.

[75 FR 51589, Aug. 20, 2010]

General Compliance Requirements

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations and operating limitations in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation

and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010]

Testing and Initial Compliance Requirements

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or

reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

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

Where:

C_i= concentration of CO or formaldehyde at the control device inlet,

C_o= concentration of CO or formaldehyde at the control device outlet, and

R = percent reduction of CO or formaldehyde emissions.

(2) You must normalize the carbon monoxide (CO) or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2concentration is measured in lieu of oxygen concentration measurement, a CO_2correction factor is needed. Calculate the CO_2correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific $F_o$value for the fuel burned during the test using values obtained from Method 19, section 5.2, and the following equation:

$$F_o = \frac{0.209\, F_d}{F_c} \qquad \text{(Eq. 2)}$$

Where:

F_o= Fuel factor based on the ratio of oxygen volume to the ultimate CO_2volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d= Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

F_c= Ratio of the volume of CO_2produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

(ii) Calculate the CO_2correction factor for correcting measurement data to 15 percent oxygen, as follows:

$$X_{co_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 3)}$$

Where:

X_{co2}= CO_2correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2correction value, percent.

(iii) Calculate the $NO_X$and SO_2gas concentrations adjusted to 15 percent O_2using CO_2as follows:

$$C_{adj} = C_d \frac{X_{co_2}}{\%CO_2} \qquad \text{(Eq. 4)}$$

Where:

%CO_2= Measured CO_2concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010]

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either oxygen or CO_2at both the inlet and the outlet of the control device according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (5) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start landfill or digester gas stationary RICE located at an area source of HAP emissions;

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (g)(2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska not accessible by the FAHS do not have to meet the requirements of paragraph (g) of this section.

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates, and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number,

viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011]

§ 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

Continuous Compliance Requirements

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are

deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) [Reserved]

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) *Requirements for emergency stationary RICE.* (1) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed on or after June 12, 2006, or an existing emergency stationary RICE located at an area source of HAP emissions, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1)(i) through (iii) of this section. Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1)(i) through (iii) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency RICE beyond 100 hours per year.

(iii) You may operate your emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, and the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations. The supply of emergency power to another entity

or entities pursuant to financial arrangement is not limited by this paragraph (f)(1)(iii), as long as the power provided by the financial arrangement is limited to emergency power.

(2) If you own or operate an emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed prior to June 12, 2006, you must operate the engine according to the conditions described in paragraphs (f)(2)(i) through (iii) of this section. If you do not operate the engine according to the requirements in paragraphs (f)(2)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance.

(iii) You may operate your emergency stationary RICE for an additional 50 hours per year in non-emergency situations. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010]

Notifications, Reports, and Records

§ 63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010]

§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010]

§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) or (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010]

§ 63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

Other Requirements and Information

§ 63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in §63.6610(b).

§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101–549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, *etc.* Stationary RICE used for peak shaving are not considered emergency stationary RICE. Stationary RICE used to supply power to an electric grid or that supply non-emergency power as part of a financial arrangement with another entity are not considered to be emergency engines, except as permitted under §63.6640(f). All emergency stationary RICE must comply with the requirements specified in §63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in §63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to

subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X(such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011]

Table 1ato Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

Table 1bto Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed Spark Ignition 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions and Existing Spark Ignition 4SRB Stationary RICE >500 HP Located at an Area Source of HAP Emissions

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions and existing 4SRB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	You must meet the following operating limitation . . .
1. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using	a. Maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst

NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O2 and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O2 and using NSCR.	measured during the initial performance test; and b. Maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.
2. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O2 and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O2 and not using NSCR.	Comply with any operating limitations approved by the Administrator.

[76 FR 12867, Mar. 9, 2011]

Table 2ato Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe

	15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2until June 15, 2007	loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

Table 2bto Subpart ZZZZ of Part 63— Operating Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing Compression Ignition Stationary RICE >500 HP, and Existing 4SLB Stationary RICE >500 HP Located at an Area Source of HAP Emissions

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and compression ignition stationary RICE located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; existing compression ignition stationary RICE >500 HP; and existing 4SLB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	You must meet the following operating limitation . . .
1. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance

stationary RICE exhaust and using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and not using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst	Comply with any operating limitations approved by the Administrator.

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(g) for a different temperature range.

[75 FR 51593, Aug. 20, 2010, as amended at 76 FR 12867, Mar. 9, 2011]

Table 2cto Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]

	operation or annually, whichever comes first, and replace as necessary.[3]	
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[2]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2	
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first;	

	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2	
11. Non-emergency,	Limit concentration of	

non-black start 4SRB stationary RICE 100≤HP≤500	formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2	
12. Non-emergency, non-black start landfill or digester gas-fired stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2	

[1]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[2]Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 51593, Aug. 20, 2010]

Table 2dto Subpart ZZZZ of Part 63— Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
	b. Inspect air cleaner every 1,000 hours of operation or annually,	

	whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	

24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start	a. Limit concentration	

4SLB stationary RICE >500 HP	of CO in the stationary RICE exhaust to 47 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 93 percent or more.	
9. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
10. Non-emergency, non-black start 4SRB stationary RICE >500 HP	a. Limit concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd at 15 percent O_2; or	
	b. Reduce formaldehyde emissions by 76 percent or more.	
11. Non-emergency, non-black start landfill or digester gas-fired stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and	

	belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1]Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[75 FR 51595, Aug. 20, 2010]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE with a brake horsepower >500 located at major sources; new or reconstructed 4SLB stationary RICE with a brake horsepower ≥250 located at major sources; and new or reconstructed CI stationary RICE with a brake horsepower >500 located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE with a brake horsepower ≥5,000 located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE with a brake horsepower >500 located at major sources and new or reconstructed 4SLB stationary RICE with a brake horsepower 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are not limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB	Limit or reduce CO or formaldehyde emissions	Conduct subsequent performance tests every 8,760 hrs. or 3 years, whichever comes first.

stationary RICE located at an area source of HAP emissions with a brake horsepower >500 that are operated more than 24 hours per calendar year that are not limited use stationary RICE		
5. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE located at an area source of HAP emissions with a brake horsepower >500 that are operated more than 24 hours per calendar year and are limited use stationary RICE	Limit or reduce CO or formaldehyde emissions	Conduct subsequent performance tests every 8,760 hrs. or 5 years, whichever comes first.

[1]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[75 FR 51596, Aug. 20, 2010]

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

As stated in §§63.6610, 63.6611, 63.6612, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. Reduce CO emissions	i. Measure the O_2 at the inlet and outlet of the control device; and	(1) Portable CO and O_2 analyzer	(a) Using ASTM D6522–00 (2005)[a] (incorporated by reference, see §63.14). Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet of the control device	(1) Portable CO and O_2 analyzer	(a) Using ASTM D6522–00 (2005)[ab] (incorporated by reference, see §63.14) or Method 10 of 40 CFR appendix A. The CO concentration must be at 15 percent O_2, dry basis.
2. 4SRB	a. Reduce	i. Select the	(1) Method 1 or 1A of	(a) Sampling sites must be

stationary RICE	formaldehyde emissions	sampling port location and the number of traverse points; and	40 CFR part 60, appendix A §63.7(d)(1)(i)	located at the inlet and outlet of the control device.
		ii. Measure O_2at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00m (2005)	(a) Measurements to determine O_2concentration must be made at the same time as the measurements for formaldehyde concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[c]provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A §63.7(d)(1)(i)	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (2005)	(a) Measurements to determine O_2concentration must be made at the same time and location as the measurements for

				formaldehyde concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[c]provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. Measure CO at the exhaust of the stationary RICE	(1) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00 (2005),[a]Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03	(a) CO Concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour longer runs.

[a]You may also use Methods 3A and 10 as options to ASTM–D6522–00 (2005). You may obtain a copy of ASTM–D6522–00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106. ASTM–D6522–00 (2005) may be used to test both CI and SI stationary RICE.

[b]You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.

[c]You may obtain a copy of ASTM–D6348–03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[75 FR 51597, Aug. 20, 2010]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations and Operating Limitations

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if. . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP,	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and

and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2or CO_2at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2or CO_2at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a

stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year		performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using §63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during

		the initial performance test.
9. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of formaldehyde and not using NSCR	i. The average formaldehyde concentration determined from the initial performance test is less than or equal to the formaldehyde emission limitation; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
11. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved

		operating parameters (if any) during the initial performance test.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO or formaldehyde emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
13. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.

[76 FR 12867, Mar. 9, 2011]

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, Operating Limitations, Work Practices, and Management Practices

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved;[a]and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure

		drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved;[a]and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP, existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to §63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to §63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and

		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to §63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;[a]and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month

		and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;[a]and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency landfill or digester gas stationary SI RICE located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not using oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating

		limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using an oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not using an oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour

		rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

[a]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[76 FR 12870, Mar. 9, 2011]

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in §63.6650, you must comply with the following requirements for reports:

For each ...	You must submit a ...	The report must contain ...	You must submit the report ...
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP and operated more than 24 hours per calendar year; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in	

non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP		§63.6650(e); or c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4) i. Semiannually according to the requirements in §63.6650(b)(1)–(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)–(9) for engines that are limited use stationary RICE subject to numerical emission limitations. i. Semiannually according to the requirements in §63.6650(b). i. Semiannually according to the requirements in §63.6650(b).	
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and i. Annually, according to the requirements in §63.6650.	
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and i. See item 2.a.i.	
		c. Any problems or errors suspected with the meters. i. See item 2.a.i.	

[75 FR 51603, Aug. 20, 2010]

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in §63.6665, you must comply with the following applicable general provisions.

General	Subject of citation	Applies to	Explanation

provisions citation		subpart	
§63.1	General applicability of the General Provisions	Yes.	
§63.2	Definitions	Yes	Additional terms defined in §63.6675.
§63.3	Units and abbreviations	Yes.	
§63.4	Prohibited activities and circumvention	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)–(4)	Compliance dates for new and reconstructed sources	Yes.	
§63.6(b)(5)	Notification	Yes.	
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§63.6(c)(1)–(2)	Compliance dates for existing sources	Yes.	
§63.6(c)(3)–(4)	[Reserved]		
§63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§63.6(d)	[Reserved]		
§63.6(e)	Operation and maintenance	No.	
§63.6(f)(1)	Applicability of standards	No.	
§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)–(3)	Use of alternate standard	Yes.	
§63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.

§63.6(i)	Compliance extension procedures and criteria	Yes.	
§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)–(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§63.6610, 63.6611, and 63.6612.
§63.7(a)(3)	CAA section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes	Except that §63.7(b)(1) only applies as specified in §63.6645.
§63.7(b)(2)	Notification of rescheduling	Yes	Except that §63.7(b)(2) only applies as specified in §63.6645.
§63.7(c)	Quality assurance/test plan	Yes	Except that §63.7(c) only applies as specified in §63.6645.
§63.7(d)	Testing facilities	Yes.	
§63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at §63.6620.
§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	
§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at §63.6625.

§63.8(a)(2)	Performance specifications	Yes.	
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring for control devices	No.	
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)–(3)	Multiple effluents and multiple monitoring systems	Yes.	
§63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	Yes.	
§63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	Yes.	
§63.8(c)(2)–(3)	Monitoring system installation	Yes.	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§63.8(c)(6)–(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§63.8(d)	CMS quality control	Yes.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
		Except that §63.8(e) only applies as specified in §63.6645.	
§63.8(f)(1)–(5)	Alternative monitoring method	Yes	Except that §63.8(f)(4) only applies as specified in §63.6645.
§63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that §63.8(f)(6) only applies as specified in §63.6645.

§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6635 and 63.6640.
§63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§63.9(b)(1)–(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
		Except that §63.9(b) only applies as specified in §63.6645.	
§63.9(c)	Request for compliance extension	Yes	Except that §63.9(c) only applies as specified in §63.6645.
§63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that §63.9(d) only applies as specified in §63.6645.
§63.9(e)	Notification of performance test	Yes	Except that §63.9(e) only applies as specified in §63.6645.
§63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	Except that §63.9(g) only applies as specified in §63.6645.
§63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that §63.9(g) only applies as	

		specified in §63.6645.	
§63.9(h)(1)–(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
			Except that §63.9(h) only applies as specified in §63.6645.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	
§63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	
§63.10(b)(1)	Record retention	Yes.	
§63.10(b)(2)(i)–(v)	Records related to SSM	No.	
§63.10(b)(2)(vi)–(xi)	Records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	
§63.10(c)	Additional records for sources using CEMS	Yes	Except that §63.10(c)(2)–(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.

§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that §63.10(e)(3)(i)(C) is reserved.
§63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§63.11	Flares	No.	
§63.12	State authority and delegations	Yes.	
§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010]

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the Technical Support Document (ATSD) for a PSD/New Source Construction and Part 70 Operating Permit (TITLE V)

Source Description and Location

Source Name:	**St. Joseph Energy Center, LLC**
Source Location:	**Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552**
County:	**St. Joseph**
SIC Code:	**4911**
Operation Permit No.:	**T 141-31003-00579**
Operation Permit Issuance Date:	**Yet to be issued**
Permit Reviewer:	**Josiah Balogun**

Public Notice Information

On August 29, 2012, the Office of Air Quality (OAQ) had a notice published in the South Bend Tribune in South Bend, Indiana, stating that St. Joseph Energy Center, LLC had applied for a Part 70 Operating Permit (TITLE V) to operate a nominal 1,350 megawatt (MW) combined cycle combustion turbine (CCCT) electric generating facility (CCCT Facility). The notice also stated that OAQ proposed to issue a Title V permit for this operation and provided information on how the public could review the proposed Title V permit and other documentation. Finally, the notice informed interested parties that there was a period of forty two (42) days to provide comments on whether or not this Title V permit should be issued as proposed.

On October 4, 2012, the Office of Air Quality (OAQ) held a public meeting and hearing at the New Prairie High School Auditorium in New Carlisle, Indiana, for citizens and interested parties to discuss questions and concerns related to the project.

No changes have been made to the TSD because the OAQ prefers that the Technical Support Document reflects the permit that was on public notice. Changes that occur after the public notice are documented in this Addendum to the Technical Support Document. This accomplishes the desired result, ensuring that these types of concerns are documented and part of the record regarding this permit decision.

Comments Received from USEPA

On February 2, 2012, Sam Portanova of USEPA submitted comments on the proposed Title V Operating Permit. The comments are summarized in the subsequent pages, with IDEM's corresponding responses.

The Combined Cycle Combustion Turbine (CCCT) startup/shutdown Best Available Control Technology (BACT) limits in permit condition D.1.11 are as follows: 22 tons of Volatile Organic Compounds (VOC) per 12-month period, 407.5 tons of Carbon Monoxide (CO) per 12-month period, and 81.6 tons of Nitrogen Oxides (NOx) per 12-month period. In addition, this permit condition limits CO emissions to 2,125 pounds per event and NOx emissions to 443 pounds per event (where an "event" is defined as a single startup or shutdown).

Comment 1: The BACT analysis in Appendix B of the Technical Support Document (TSD) does not include an analysis of the startup/shutdown limits selected as BACT for VOC, CO, and NOx emissions from the CCCTs. The permit should include an analysis for the selection

of these BACT limits for startup and shutdown events.

Response 1: The secondary BACT limits are justified for NO_X, CO, and VOC emissions during startup and shutdown events in the permit application submitted by St. Joseph Energy Center, LLC. The secondary NO_X, CO, and VOC limits for startup and shutdown events are mass-based limits on a ton per year basis. Annual mass limits are based on 4 hot starts, 198 warm starts, 16 cold starts, and 218 shutdowns per year for each turbine, using per event emission rates provided by the combustion turbine vendor. The number of each type of startup is not suitable as a permit condition as the number and blend of hot, warm, and cold starts and plant shutdowns will vary over the plant life based on market demand for power.

As stated above, BACT for startup and shutdown emissions are established as rolling, 12-month emission limits. However, the pounds per event emission limits for NO_X and CO were not established as BACT. These limits were incorporated into the permit to demonstrate continuous compliance with the emission rates used to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS) during startup and shutdown events.

Comment 2: The potential to emit table on page 7 of the TSD lists total CO emissions from the four CCCTs as 130 tons per year (tpy) per turbine, which is a total 520 tpy for the CCCTs. Does this amount account for the 407.5 tons of CO per 12-month period allowed in permit condition D.1.11(i) during startup/shutdown events?

The potential to emit table on page 7 of the TSD lists total VOC emissions from the four CCCTs as 24.97 tpy per turbine, which is a total 99.88 tpy for the CCCTs. Does this amount account for the 22.0 tons of VOC per 12-month period allowed in permit condition D.1.11(j) during startup/shutdown events?

The potential to emit table on page 7 of the TSD lists total NOx emissions from the four CCCTs as 71.8 tpy per turbine, which is a total 287.2 for the CCCTs. Does this amount account for the 81.6 tons of NOx per 12-month period allowed in permit condition D.1.11(h) during startup/shutdown events?

Response 2: The CCCT potential to emit (PTE) for CO, NO_X, and VOC include emissions during both startup/shutdown events and emissions during steady state operation. See page 9 of 22 TSD App A of the calculations.

Comment 3: The Greenhouse Gas (GHG) BACT emission calculations in permit condition D.1.15 are based on emission factors from 40 C.F.R. Part 98, Subpart C. Permit condition D.1.17 requires GHG stack testing once every 5 years. While EPA agrees with the use of the 40 C.F.R. Part 98 emission factors in calculating GHG emissions, the Indiana Department of Environmental Management (IDEM) should clarify in the permit that the results of future stack tests can be used to determine a source-specific emission factor to calculate GHG emissions from this facility.

Response 3: Permit condition D.1.17(c) requires a heat rate performance test for the CCCTs to verify compliance with the greenhouse gas (GHG) limit in condition D.1.10(a). The heat rate performance test will evaluate efficiency of the CCCT by comparing heat input from natural gas to the net power output, but will not monitor actual GHG emissions from the CCCT stacks. Therefore, there is no current need to revise permit condition D.1.17 to allow for use of future stack tests to determine source-specific GHG emissions factors. Should any future need to establish source-specific emissions factors for demonstrating compliance with Condition D.1.10(b) arise in the future, any necessary permit updates can be incorporated at that time.

Comment 4: The permit does not include monitoring for the sulfuric acid mist and sulfur dioxide BACT emission limits for the CCCTs. The permit should include a method of demonstrating compliance with the fuel sulfur limit of 0.75 grains of sulfur/100 standard cubic feet fuel listed in permit conditions D.1.5 and D.1.7.

Response 4: IDEM has added a record keeping requirements to demonstrate compliance with the SO_2 and H_2SO_4 BACT limits established for the CCCTs.

D.1.19 Record Keeping Requirement

****

(e) In order to document the compliance status with Condition**s D.1.4, D.1.5, D.1.6, D.1.7, D.1.8, D.1.9 and** D.1.10 ~~- GHGs PSD BACT~~, the Permittee shall maintain monthly records of the amount and type of fuel combusted in the combined cycle combustion turbines.

.....

(h) To document the compliance status with Condition D.1.5 - H_2SO_4 PSD BACT and D.1.7 - SO_2 PSD BACT, the Permittee shall maintain the monthly records of the fuel sulfur content of the natural gas combusted in the turbines and the associated duct burners.

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

Comment 5: Permit condition D.1.17(a) requires a Particulate Matter (PM) stack test every five years to demonstrate compliance with the BACT limits in permit condition D.1.4. However, the permit does not require periodic monitoring to demonstrate compliance with the PM limits in between the stack tests. IDEM should either demonstrate how compliance with the PM limits is sufficiently assured with the stack test or require additional periodic monitoring in the intervening period between stack tests.

Response 5: Additional compliance monitoring for particulate matter (PM) BACT limits is not required because the CCCTs have no control device to control PM emissions. The BACT limits are met using natural gas as fuel and good combustion practices. Since only natural gas may be used as fuel for the CCCT and the continuous emissions monitoring systems (CEMS) for CO will verify good combustion practices on a continuous basis, additional compliance monitoring specifically for PM is not necessary. This approach is consistent with recent permits issued with PM BACT limits for CCCT facilities.

Comments Received from the Source

On September 27, 2012, David Dempsey of Trinity Consultant submitted comments on the proposed Title V Operating Permit. The comments are summarized in the subsequent pages, with IDEM's corresponding responses.

The summary of the comments and IDEM, OAQ responses, including changes to the permit No. 141-31003-00579 (language deleted is shown in ~~strikeout~~ and language added is shown in **bold**) are as follows:

Comment 1: **Permit Condition D.6.7**
Condition D.6.5 only applies during transfer of gasoline between any transport and any gasoline storage tank. Since permit condition D.6.7 serves as the compliance determination requirement for condition D.6.5, we request the condition be updated as follows - *"In order to comply with Condition D.6.5, the Stage I vapor recovery systems for VOC control shall be in operation at all times when gasoline is being transferred~~, or~~*

~~dispensed~~."

Response 1: The typo in Condition D.6.7 - Volatile Organic Compounds Control has been corrected in the permit accordingly.

D.6.7 Volatile Organic Compounds Control

In order to comply with Condition D.6.5, the Stage I vapor recovery systems for VOC control shall be in operation at all times when gasoline is being transferred~~, or dispensed~~.

Comment 2: **Permit Condition F.4.1(b)**
Please add the following clarification - "*... monitor certification requirements under ~~section~~* ***326 IAC 24-1-****11(c)(1), 11(c)(2), or 11(c)(5)~~ of this rule~~ and for each control period thereafter.*"

Response 2: The rule citation has been added to Condition F.4.1(b) of the permit.

F.4.1 Nitrogen Oxides Emission Requirements [326 IAC 24-1-4(c)] [40 CFR 97.106(c)]

.....

(b) A CAIR NO_X unit shall be subject to the requirements under (a) above for the control period starting on the later of January 1, 2009, or the deadline for meeting the unit's monitor certification requirements under section **326 IAC 24-1-**11(c)(1), 11(c)(2), or 11(c)(5) ~~of this rule~~ and for each control period thereafter.

Comment 3: **Permit Condition F.4.2(b)**
Please add the following clarification - "*... monitor certification requirements under ~~section~~****326 IAC 24-2-****10(c)(1), 10(c)(2), or 10(c)(5)~~ of this rule~~ and for each control period thereafter*."

Response 3: The rule citation has been added to Condition F.4.2(b) of the permit.

F.4.2 Sulfur Dioxide Emission Requirements [326 IAC 24-2-4(c)] [40 CFR 97.206(c)]

.....

(b) A CAIR SO_2 unit shall be subject to the requirements under (a) above for the control period starting on the later of January 1, 2010 or the deadline for meeting the unit's monitor certification requirements under section **326 IAC 24-2-**10(c)(1), 10(c)(2), or 10(c)(5) ~~of this rule~~ and for each control period thereafter.

Comment 4: **Permit Condition F.4.3(b)**
Please add the following clarification - "*... certification requirements under ~~section~~* ***326 IAC 24-3-****11(c)(1), 11(c)(2), 11(c)(3), or 11(c)(7) ~~of this rule~~ and for each control period thereafter.*"

Response 4: The rule citation has been added to Condition F.4.3(b) of the permit.

F.4.3 Nitrogen Oxides Ozone Season Emission Requirements [326 IAC 24-3-4(c)] [40 CFR 97.306(c)]

.....

(b) A CAIR NO_X unit shall be subject to the requirements under (a) above for the control period starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under section **326 IAC 24-3-**11(c)(1), 11(c)(2), 11(c)(3), or 11(c)(7) ~~of this rule~~ and for each control period thereafter.

Comment 5: **TSD Page 16 of 27**
The PM, PM10, and PM2.5 emission limit for the CCCT is incorrectly listed as 0.0065 lb per MMBtu without duct firing. Per condition D.1.4(b) of the draft permit, the correct limit is 0.0092 lbs/MMBtu without duct firing.

Response 5: IDEM agrees, however no changes shall be made to the Technical Support Document (TSD) because the OAQ prefers that the TSD reflects the permit that was public noticed. The correction is documented here as part of this addendum.

Comment 6: **TSD Pages 16 and 17 of 27**
As noted in conditions D.1.6, D.1.8, and D.1.9 of the draft Title V permit, the control requirements and emission limits for CO (item 3), VOC (item 5), and NOx (item 6) do not apply during startup and shutdown events.

Response 6: IDEM agrees, however no changes shall be made to the Technical Support Document (TSD) because the OAQ prefers that the TSD reflects the permit that was public noticed.

Comments Received from the Public

OAQ received comments from the following people (and groups of people) during the public meeting and public hearing:

Speakers Present at the Public Hearing and Public Meeting

1. Mike Campton
2. Jeff Rea
3. Robert Kovach
4. Rafael Morton
5. Donald Fozo
6. James Scheetz
7. Charles Dadlow

The summary of the comments and IDEM, OAQ responses, including changes to the permit No. 141-31003-00579 (language deleted is shown in ~~strikeout~~ and language added is shown in **bold**) are as follows:

Comment 1: Which agency monitors the pipeline, please provide the contact name and information? **(Susan Jones)**

Response 1: The Indiana Utility Regulatory Commission's Pipeline Safety Division receives federal authority from the U.S. Department of Transportation to conduct inspections, investigate incidents, and enforce federal safety regulations and state statutes and rules regarding natural gas pipelines. The division also monitors and evaluates regulatory and policy initiatives and advises the Commission about proceedings initiated by Indiana's system operators. It is also responsible for educating public officials and emergency responders on how to recognize, report, and respond to gas-related emergencies.

The Pipeline Safety Division's mailing address is:

Indiana Utility Regulatory Commission
Pipeline Safety Division
101 W. Washington St, STE 1500E
Indianapolis, Indiana 46204

Steve Allen, the Pipeline Safety Director, can be reached at 317-232-2785. William "Bill" Boyd, the Pipeline Safety Program Manager, can be reached at 317-232-2718.

More information about the IURC's Pipeline Safety Division can be found at http://www.in.gov/iurc/2335.htm on the Internet.

Comment 2: Who within the IDEM office of Air Quality is responsible for monitoring the cumulative impact of these IDEM-approved operations? **(Jack Daly)**

Response 2: The cumulative impact of the combined emissions from all sources in the ambient air is monitored by IDEM's Office of Air Quality, Air Monitoring Branch. Air quality monitoring is conducted at monitoring sites across the state. The monitoring sites collect ambient air data on an hourly basis regarding the concentration of ozone, particulate matter (PM10), fine particulate matter (PM2.5), oxides of nitrogen (NOx), carbon monoxide (CO), sulfur dioxide (SO2) and toxics. The air quality data from these monitoring sites can be viewed at http://www.in.gov/idem/airfacts/ on IDEM's website. More information about the air quality monitoring network is available at http://www.in.gov/idem/4652.htm on IDEM's website.

Comment 3: Who in the IDEM hierarchy watches that the total emission levels remain within the acceptable limits? **(Jack Daly)**

Response 3: The mission of IDEM's Office of Air Quality is to assure all Hoosiers ambient air quality that meets the National Ambient Air Quality Standards. The U.S. Environmental Protection Agency (U.S. EPA) sets National Ambient Air Quality Standards (NAAQS) for six common air pollutants, also called "criteria" pollutants. The criteria pollutants are carbon monoxide, nitrogen dioxide, ozone, lead, particulate matter and sulfur dioxide. NAAQS are often referred to as federal health standards for outdoor air. More information about these pollutants is available at www.epa.gov/air/airpollutants.html on U.S. EPA's website. The complete table of the NAAQS can be found at the www.epa.gov/air/criteria.html website. As described in Response 2, above, IDEM's Office of Air Quality, Air Monitoring Branch, conducts ambient air monitoring that measures whether the standards are being met

IDEM's Office of Air Quality, Programs Branch, conducts computer modeling of ambient air emission levels using emission information and other data to determine if each area in Indiana will meet all the NAAQS. If an area is found to not meet a health standard, the area will be designated as a nonattainment area. The Programs Branch works with businesses, local governments, and the public to reduce the emissions from air emission sources in order to bring a nonattainment area back into attainment. These reductions are proposed in rulemakings before the Indiana Air Pollution Control Board. More information about attainment and nonattainment areas is available at http://www.in.gov/idem/4654.htm#howdo on IDEM's website. More information about the Indiana Air Pollution Control Board and the rulemaking process is available at http://www.in.gov/idem/4087.htm on the Internet.

IDEM's Office of Air Quality, Air Compliance and Enforcement Branch, uses all compliance tools and resources available to improve air quality by ensuring that all air pollution sources are in compliance with all state and federal air pollution laws, rules and permits. The branch determines compliance of regulated sources of air emissions by inspecting, monitoring, testing, and reviewing records. The branch has inspectors that conduct inspections, respond to complaints, provide compliance assistance to sources and provide input on permits and rules. The branch's Compliance Data section reviews and approves stack tests and emissions monitors. All branch sections coordinate with the four IDEM regional offices.

The air inspector for this source is Rick Reynolds. Mr. Reynolds works out of IDEM's Northern Regional Office, 300 N Michigan St, Suite 450, South Bend, Indiana 46601-1295, telephone (574) 245-4888, toll free (800) 753-5519, fax (574) 245-4877. Anyone concerned about a possible emission violation should contact Mr. Reynolds with their complaint. Environmental complaints may also be filed on-line at www.idem.IN.gov/5274.htm or by calling IDEM's Complaint Coordinator at (800) 451-6027, ext. 2-4464.

Comment 4: Who in IDEM's Air Quality Division ensures that the date on which a decision to approve or deny a permit application is accurate? **(Jack Daly)**

Response 4: Air permit application decisions are reviewed by the Permits Branch in IDEM's Office of Air Quality. The Permits Branch Chief, Matt Stuckey, ensures that the date placed on all final permit application decisions is accurate.

Comment 5: We are writing as the St. Joseph County Board of Commissioners in support of the St. Joseph Energy Center project in New Carlisle, Indiana. This is the type of project that can positively impact not only our local economy but the entire region as a whole. **(Robert Kovach on behalf of St. Joseph County Board of Commissioners)**

Response 5: IDEM acknowledges that these comments are important to the commenter. However, these comments do not have any direct impact on how IDEM reviews and makes decisions on air permit applications.

Comment 6: This project would be a very nice and well needed project for the construction industry in this area. **(Mike Campton)**

Response 6: IDEM acknowledges that these comments are important to the commenter. However, these comments do not have any direct impact on how IDEM reviews and makes decisions on air permit applications.

Comment 7: The problems with air quality impact our economic development efforts in this area, so we feel convinced with our conversation and the time we've spent with the developers here, the understanding of the IDEM process, that this meets all their criteria and should be approved, and we would urge you to support the granting of an air permit for this project. **(Jeff Rea)**

Response 7: IDEM acknowledges that these comments are important to the commenter. However, these comments do not have any direct impact on how IDEM reviews and makes decisions on air permit applications.

Comment 8: I want to say we totally support the project, pending the passing of all of the environmental standards. **(Morton Rafael representative of the St. Joseph County Council)**

Response 8: IDEM acknowledges that these comments are important to the commenter. However, these comments do not have any direct impact on how IDEM reviews and makes decisions on air permit applications.

Comment 9: This project would just be a tremendous boost for not only our industry, but to this community. We look forward to supporting it. **(Donald Fozo)**

Response 9: IDEM acknowledges that these comments are important to the commenter. However,

these comments do not have any direct impact on how IDEM reviews and makes decisions on air permit applications.

Comment 10: On behalf of the Building Trade, we would like to see this project move forward and we hope this permit process works well. **(James Scheetz on behalf of Building Trades)**

Response 10: IDEM acknowledges that these comments are important to the commenter. However, these comments do not have any direct impact on how IDEM reviews and makes decisions on air permit applications.

Comment 11: My biggest concern is that this project has taken three years since it's begun and I don't see anything happening. Somebody, I think is asleep on the job someplace along the line. Do you have any answer to that, why it should take so long to get a couple of permits that had been done ten years ago, and nothing's changed that much since ten years ago? **(Charles Dadlow)**

Response 11: St. Joseph Energy Center, LLC submitted its application for this permit to IDEM on October 3, 2011. The area where St. Joseph Energy Center, LLC will construct this electrical generating plant has been the subject of a previous proposal for construction of a power plant. On December 7, 2001, IDEM issued an air permit to Allegheny Energy Supply Company LLC to construct a generating plant at this location. Construction was started on that plant but never completed. The Allegheny Energy construction permit expired in 2004.

Other Changes

Upon further review IDEM, OAQ has made the following changes to the Title V permit No. T141-31003-00579. (deleted language appears as ~~strikout~~ and the new language **bolded**):

Change 1: IDEM has corrected the typo in Condition D.2.13 (d) - Testing Requirements in the permit accordingly.

D.2.13 Testing Requirements [326 IAC 2-1.1-11]

.....

(d) In order to demonstrate compliance with Condition D.2.8 - VOC PSD BACT, within sixty (60) days of reaching maximum capacity but no later than one hundred and eighty (180) days after initial startup, the Permittee shall conduct VOC emissions stack testing of the emissions from the boilers utilizing methods as approved by the commissioner. ~~This test shall be performed~~ **This test shall be repeated at least once every five years from the date of the most recent valid compliance demonstration**. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a PSD/New Source Construction and Part 70 Permit

Source Description and Location

Source Name:	**St. Joseph Energy Center, LLC**
Source Location:	**Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552**
County:	**St. Joseph**
SIC Code:	**4911**
Operation Permit No.:	**T 141-31003-00579**
Operation Permit Issuance Date:	**Yet to be issued**
Permit Reviewer:	**Josiah Balogun**

The Office of Air Quality (OAQ) has reviewed a New Source Construction and Part 70 operating permit application submitted by St. Joseph Energy Center, LLC on October 3, 2011, relating to construction and operation of a nominal 1,350 megawatt (MW) combined cycle combustion turbine (CCCT) electric generating facility (CCCT Facility).

History

St. Joseph Energy Center, LLC (SJEC) is proposing to construction and operation of a nominal 1,350 megawatt (MW) combined cycle combustion turbine (CCCT) electric generating facility (CCCT Facility). The proposed CCCT Facility will consist of a nominal net 1,350 MW natural gas-fired CCCT operation that includes two natural gas-fired 2x1 CCCT blocks and ancillary equipment to produce steam for the generation of electricity. A water treatment facility will be constructed on-site to supply SJEC operations. This facility will be operated by the town of New Carlisle, but is considered as part of the CCCT Facility for purposes of evaluating PSD air permitting requirements.

Existing Approvals

There have been no previous approvals issued to this source.

County Attainment Status

The source is located in St. Joseph County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Attainment effective July 19, 2007, for the 8-hour ozone standard.[1]
PM_{10}	Unclassifiable effective November 15, 1990.
NO_2	Cannot be classified or better than national standards.
Pb	Not designated.

[1]Attainment effective October 18, 2000, for the 1-hour ozone standard for the South Bend-Elkhart area, including St. Joseph County, and is a maintenance area for the 1-hour ozone National Ambient Air Quality Standards (NAAQS) for purposes of 40 CFR 51, Subpart X*. The 1-hour standard was revoked effective June 15, 2005.

Pollutant	Designation
Unclassifiable or attainment effective April 5, 2005, for PM2.5.	

(a) Ozone Standards
Volatile organic compounds (VOC) and Nitrogen Oxides (NOx) 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 NOx emissions are considered when evaluating the rule applicability relating to ozone. St. Joseph County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) $PM_{2.5}$
St. Joseph County has been classified as attainment for $PM_{2.5}$. On May 8, 2008 U.S. EPA promulgated the requirements for Prevention of Significant Deterioration (PSD) for $PM_{2.5}$ emissions. These rules became effective on July 15, 2008. On May 4, 2011 the air pollution control board issued an emergency rule establishing the direct $PM_{2.5}$ significant level at ten (10) tons per year. This rule became effective, June 28, 2011. Therefore, direct $PM_{2.5}$ and SO_2 emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2. See the State Rule Applicability – Entire Source section.

(c) Other Criteria Pollutants
St. Joseph County has been classified as attainment or unclassifiable in Indiana for all other 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 power plant, it is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7. Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

Description of New Source and Emission Units with Control Equipment Summary

The Office of Air Quality (OAQ) has reviewed a New Source Construction application, submitted by St. Joseph Energy Center, LLC on October 3, 2011, relating to relating to construction and operation of a nominal 1,350 megawatt (MW) combined cycle combustion turbine (CCCT) electric generating facility (CCCT Facility). The following is a list of the proposed emission unit(s) and pollution control device(s):

(a) Four (4) natural gas-fired combined cycle combustion turbines, identified as units CCCT1, CCCT2, CCCT3, and CCCT4, permitted in 2012, each with a combustion turbine equipped with dry low NOx burners, natural gas fired duct burners, and a heat recovery steam generator identified as HRSG1, HRSG2, HRSG3, and HRSG4, NOx emissions controlled by four (4) selective catalytic reduction (SCR) systems (SCR01, SCR02, SCR03 and SCR04), CO and VOC emissions controlled by oxidation catalyst systems (CAT01, CAT02, CAT03 and CAT04) and exhausting to stacks CCCT01, CCCT02, CCCT03, and CCCT04, respectively. Each stack has continuous emissions monitors (CEMS) for NOx and CO. The nominal heat input for each CCCT is 2,300 MMBtu/hr (higher heating value (HHV)). The combined nominal power output is 1,350 megawatts (MW).

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

(b) Two (2) natural gas fired auxiliary boilers, identified as B001 and B002, permitted in 2012, each, with a maximum heat input capacity of 80 MMBtu/hr (HHV), equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stacks B001 and B002. Under 40 CFR Part 60, Subpart Dc, the auxiliary boiler is considered a steam generating unit.

(c) One (1) emergency diesel generator, nominally rated at 2012 horsepower, identified as EG03, permitted in 2012, exhausting through one (1) vent, identified as EG03. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generator is considered a new affected source.]

Insignificant and Trivial Activities

The source also consists of the following insignificant activities as defined in 326 IAC 2-7-1(21):

(a) Two (2) firewater pump engines, each nominally rated at 371 brake horsepower (bph) and identified as FP01 and FP02, permitted in 2012, exhausting through two (2) vents, identified as FP01 and FP02, respectively. [Under 40 CFR 60, Subpart IIII, the firewater pump engines are considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the firewater pump engines are considered new affected sources.]

(b) Two (2) emergency diesel generators, each nominally rated at 1,006 horsepower, identified as EG01 and EG02, permitted in 2012, exhausting through two (2) vents, identified as EG01 and EG02, respectively. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generators are considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generators are considered new affected source.]

(c) Two (2) cooling towers, each nominally rated with a circulation rate of 170,000 gpm , identified as CT01 and CT02, permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through ten vents each, identified as CT01A – CT01J and CT02A – CT02J.

(d) Six (6) Turbine Lube Demister Vents, identified as DM01 - DM06, permitted in 2012, exhausting through vents DM01 – DM06.

(e) Six (6) Turbine Lube Oil storage tanks, identified as TK01 - TK06, permitted in 2012, each with a nominal capacity of 6,800 gallons.

(f) Two (2) Emergency Generator ULSD Tanks, identified as TK07 and TK08, permitted in 2012, each with a nominal capacity of 550 gallons.

(g) Two (2) Fire Pump Engine ULSD Tanks, identified as TK09 and TK10, permitted in 2012, each with a nominal capacity of 70 gallons.

(h) One (1) Vehicle Gasoline Tank, identified as TK11, permitted in 2012, with a nominal capacity of 650 gallons.

(i) One (1) Vehicle Diesel Tank, identified as TK12, permitted in 2012, with a nominal capacity of 650 gallons.

(j) One (1) Emergency Generator ULSD Tank, identified as TK50, permitted in 2012, with a nominal capacity of 300 gallons.

(k) two (2) lime storage silos, capable of handling a maximum loading rate of 20 tons per hour combined, permitted in 2012 and with particulate matter controlled by bin vent filters exhausting to Stacks S1 and S2;

(l) Six (6) Electrical Circuit Breakers containing sulfur hexafluoride (SF_6) identified as emissions unit SF6, permitted in 2012, with fugitive GHG emissions.

(m) Space heaters, process heaters, or boilers using the following fuels: Natural gas-fired combustion sources with heat input equal to or less than ten million (10,000,000) Btu per hour.

(n) The following VOC and HAP storage containers: Vessels storing lubricating oils, hydraulic oils, and machining oils.

(o) Application of the following as temporary protective coatings: greases, lubricants, nonvolatile materials, and oils.

(p) Degreasing operations that do not exceed one hundred forty-five (145) gallons per 12 months, except if subject to 326 IAC 20-6. [326 IAC 8-3];

(q) Cleaners and solvents characterized as follows where the use of which, for all cleaners and solvents combined, does not exceed one hundred forty-five (145) gallons per 12 months:

(1) Having a vapor pressure equal to or less than 2 kPa; 15 mm Hg; or 0.3 psi measured at 38 degrees C (100°F) or;

(2) Having a vapor pressure equal to or less than 0.7 kPa; 5 mm Hg; or 0.1 psi measured at 20°C (68°F);

(r) Closed loop heating and cooling systems.

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

(t) Any operation using aqueous solutons containing less than one percent (1%) by weight of VOCs excluding HAPs.

(u) Heat exchanger cleaning and repair.

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

(w) Flue gas conditioning systems and associated chemicals such as the following: Ammonia.

(x) Blowdown for any of the following: sight glass; boiler; compressors; pumps; and cooling tower.

(y) Paved and unpaved roads and parking lots with public access. [326 IAC 6-4]

(z) Grinding and machining operations controlled with fabric filters, scrubbers, mist collectors, wet collectors and electrostatic precipitators with a design grain loading of less than or equal to 0.03 grains per actual cubic foot and a gas flow rate less than or equal to 4000 actual cubic feet per minute, including the following: deburring; buffing; polishing; abrasive blasting; pneumatic conveying; and woodworking operations. [326 IAC 6-3]

Enforcement Issues

There are no pending enforcement actions.

Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

Unrestricted Potential Emissions

Pursuant to 326 IAC 2-1.1-1(10), 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. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit.

Unrestricted Potential Emissions	
Pollutant	Tons/year
PM	329
PM_{10}	326
$PM_{2.5}$	321
SO_2	102
VOC	137.4
CO	1032.70
NOx	1465.60
GHGs as CO2e	4,820,312
Pb	0.00016
H_2SO_4	78.76

HAPs	**tons/year**
Acetaldehyde	1.68
Acrolein	0.22
Benzene	0.52
Ethylbenzene	0.90
Formaldehyde	6.82
Hexane	0.57
Lead	0.00016
Propylene Oxide	1.12
Toluene	2.66
Xylenes	2.54
Other HAPs	< 0.04
Total	17.07

(a) The potential to emit (as defined in 326 IAC 2-7-1(30)) of PM10, PM2.5, SO2, VOC, CO and NOx are equal to or greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit Renewal.

(b) The potential to emit (as defined in 326 IAC 2-7-1(30)) of GHGs is equal to or greater than one hundred thousand (100,000) tons of CO_2 equivalent emissions (CO_2e) per year. Therefore, the source is subject to the provisions of 326 IAC 2-7 and will be issued a Part 70 Operating Permit Renewal.

(c) The potential to emit (as defined in 326 IAC 2-7-1(30)) of any single HAP is less than ten (10) tons per year and the potential to emit (as defined in 326 IAC 2-7-1(30)) of a combination of HAPs is less than twenty-five (25) tons per year.

Actual Emissions

No previous emission data has been received from the source.

Part 70 Permit Conditions

This source is subject to the requirements of 326 IAC 2-7, because the source met the following:

(a) Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of issuance of Part 70 permits.

(b) Monitoring and related record keeping requirements which assume that all reasonable information is provided to evaluate continuous compliance with the applicable requirements.

Potential to Emit After Issuance

The table below summarizes the potential to emit, reflecting all limits, of the emission units at the St. Joseph Energy Center, LLC. Any new control equipment is considered federally enforceable only after issuance of this Part 70 permit, and only to the extent that the effect of the control equipment is made practically enforceable in the permit.

Process/ Emission Unit	Potential To Emit (tons/year)														
	PM	PM_{10}*	$PM_{2.5}$**	SO_2	VOC	CO	NOx	H_2SO_4	NH_3	SF_6	CH_4	N_2O	CO_2	GHGs as CO_2e	HAPs
Combustion Turbine CCCT1	78.8	78.8	78.8	24.97	24.97	130	71.8	19.7	69.4	0	21.7	2.17	1,183,104	1,184,234	3.09
Combustion Turbine CCCT2	78.8	78.8	78.8	24.97	24.97	130	71.8	19.7	69.4	0	21.7	2.17	1,183,104	1,184,234	3.09
Combustion Turbine CCCT3	78.8	78.8	78.8	24.97	24.97	130	71.8	19.7	69.4	0	21.7	2.17	1,183,104	1,184,234	3.09
Combustion Turbine CCCT4	78.8	78.8	78.8	24.97	24.97	130	71.8	19.7	69.4	0	21.7	2.17	1,183,104	1,184,234	3.09
Aux. Boiler B001	2.63	2.63	2.63	0.77	1.75	28.91	10.99	0	0	0	0.77	0.08	40,958	40,998	0.3
Aux. Boiler B002	2.63	2.63	2.63	0.77	1.75	28.91	10.99	0	0	0	0.77	0.08	40,958	40,998	0.3
Cooling Tower CT01	3.73	2.37	0.01	0	0	0	0	0	0	0	0	0	0	0	0
Cooling Tower CT02	3.73	2.37	0.01	0	0	0	0	0	0	0	0	0	0	0	0
Firewater Pump FP01	0.03	0.03	0.03	0.19	0.03	0.43	0.5	0	0	0	0.003	0.001	86	86	0.0025
Firewater Pump PF02	0.03	0.03	0.03	0.19	0.03	0.43	0.5	0	0	0	0.003	0.001	86	86	0.0025
Emergency Gen. EG01	0.08	0.08	0.08	0	0.05	1.45	2.65	0	0	0	0.01	0.002	229	300	0.003
Emergency Gen. EG02	0.08	0.08	0.08	0	0.05	1.45	2.65	0	0	0	0.01	0.002	229	300	0.003
Emergency Gen. EG03	0.03	0.03	0.03	0.01	0.12	0.49	0.64	0	0	0	0.02	0.005	584	586	0.01

Process/ Emission Unit	Potential To Emit (tons/year)														
	PM	PM_{10}*	$PM_{2.5}$**	SO_2	VOC	CO	NOx	H_2SO_4	NH_3	SF_6	CH_4	N_2O	CO_2	GHGs as CO_2e	HAPs
Turbine Lube Oil Demister Vents DM01 – DM06	0.35	0.35	0.35	0	0.35	0	0	0	0	0	0	0	0	0	0
Storage Tanks	0	0	0	0	0.11	0	0	0	0	0	0	0	0	0	0
Six (6) Circuit Breakers	0	0	0	0	0	0	0	0	0	0.0009	0	0	0	22	0
Two (2) Lime Silos	0.11	0.11	0.11	0	0	0	0	0	0	0	0	0	0	0	0
Total Emission for New Source Construction	329	326	321	102	104	582	316	79	277	0.0009	89	8.9	4,815,686	4,820,312	12.98
Title V Major Source Thresholds	NA	100	100	100	100	100	100	--	--	--	--	--	--	100,000 CO_2e	10/25
Significant Level	25	15	10	40	40	100	40	7	--	--	--	--	--	75,000 CO_2e	---

negl. = negligible
*Under the Part 70 Permit program (40 CFR 70), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM10), not particulate matter (PM), is considered as a "regulated air pollutant".
**$PM_{2.5}$ listed is direct $PM_{2.5}$.

This new stationary source is a major stationary source, under PSD (236 IAC 2-2), because a regulated pollutant is emitted at a rate of 100 tons per year or more, emissions of GHGs are equal to or greater than one hundred thousand (> 100,000) tons of CO2 equivalent emissions (CO2e) per year, which is greater than the PSD threshold and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1). Therefore, pursuant to 326 IAC 2-2, the PSD requirements do apply to the new source.

Federal Rule Applicability

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to each existing pollutant-specific emission unit that meets the following criteria:

(1) has a potential to emit before controls equal to or greater than the major source threshold for the pollutant involved;

(2) is subject to an emission limitation or standard for that pollutant; and

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to each existing emission unit and specified pollutant subject to CAM:

Emission Unit / Pollutant	Control Device Used	Emission Limitation (Y/N)	Uncontrolled PTE (tons/year)	Controlled PTE (tons/year)	Major Source Threshold (tons/year)	CAM Applicable (Y/N)	Large Unit (Y/N)
Combustion Turbine CCCT1 (CO)	Y	Y	242.65	130.03	100	Y	Y
Combustion Turbine CCCT2 (CO)	Y	Y	242.65	130.03	100	Y	Y
Combustion Turbine CCCT3 (CO)	Y	Y	242.65	130.03	100	Y	Y
Combustion Turbine CCCT4 (CO)	Y	Y	242.65	130.03	100	Y	Y
Combustion Turbine CCCT1 (NOx)	Y	Y	359.16	71.83	100	Y	N
Combustion Turbine CCCT2 (NOx)	Y	Y	359.16	71.83	100	Y	N
Combustion Turbine CCCT3 (NOx)	Y	Y	359.16	71.83	100	Y	N
Combustion Turbine CCCT4 (NOx)	Y	Y	359.16	71.83	100	Y	N

The CCCTs have pre-controlled emissions greater than 100 tpy for NO_X and CO and will utilize SCR to control NO_X emissions and oxidation catalyst to control CO emissions in order to meet federally enforceable BACT emission limits. Compliance with these limits will be demonstrated through use of NOx and CO CEMS. Upon incorporation into a Title V permit, the use of CEMS is considered a continuous compliance determination method. Therefore, the BACT limits for NOx and CO are exempt from CAM in accordance with 40 CFR 64.2(b)(1)(vi). The only other PSD-regulated pollutant from the CCCTs utilizing a control device to meet an emission limit is VOC. However, pre-controlled emissions of VOC will not exceed 100 tpy, and will not be subject to CAM.

All other units at the CCCT Facility have pre-controlled emissions less than the major source threshold and/or do not use a control device as defined by the CAM regulations.

Based on this evaluation, the requirements of 40 CFR Part 64, CAM is not applicable to any emission units as part of this Part 70 operating permit.

(b) The requirements of Standards of Performance for Fossil-Fuel Fired Steam Generators for which construction is commenced after August 17, 1971, 40 CFR 60, Subpart D is not applicable to any sources in this project. The requirements of this rule apply to steam-generating units that commence construction, modification, or reconstruction after August 17, 1971, and that have a heat input capacity from fuels combusted in the steam generating unit of greater than 73 MW (250 million Btu/hour). The auxiliary boilers have a heat input capacity less than 250 MMBtu/hr, each; therefore, the auxiliary boilers are exempt from the requirements of NSPS Subpart D.

(c) The requirements of Standards of Performance for Electric Utility Steam Generating Units for which construction is commenced after September 18, 1978, 40 CFR 60, Subpart Da (NSPS Da) applies to certain electric utility steam generating units (EUSGU). EUSGU is defined as any steam electric generating unit that is constructed to supply more than one-third of its potential electric output capacity (PEOC) and 25 MW net electric output to a utility power distribution system for sale (40 CFR 60.41Da). EUSGU that are capable of combusting more than 250 MMBtu/hr of fossil fuel and that commence construction or modification after September 18, 1978, are subject to NSPS Da unless exempted [40 CFR 60.40Da(a)]. Furthermore, under 40 CFR 60.40Da(e)(1), HRSGs used with duct burners and associated with electric utility combined cycle gas turbines that are capable of combusting more than 250 MMBtu/hr of fossil fuel are subject to NSPS Da unless the HRSG meets the applicability requirements and is subject to NSPS KKKK. The HRSG meets the applicability requirements and is subject to NSPS KKKK. Therefore, the proposed duct burners are not subject to the requirements of NSPS Da.

(d) The requirements of the New Source Performance Standard, 40 CFR 60, Subpart Db, Standard of Performance for Industrial -Commercial-Institutional Steam Generating Units, which is incorporated by reference as 326 IAC 12, applies to each steam generating unit with a heat input capacity greater than 100 MMBtu/hr unless the unit meets any of the exemptions identified in 40 CFR 60.40Db. Per 40 CFR 60.40Db(i), HRSGs that are associated with combined cycle gas turbines and that meet the applicability requirements of NSPS KKKK are not subject to NSPS Subpart Db. The proposed duct burners have a heat input capacity greater than 100 MMBtu/hr, but the HRSGs are associated with combined cycle gas turbines and meet the applicability requirements of NSPS KKKK. Therefore, the proposed duct burners are not subject to the requirements of NSPS Db.

(e) The requirements of the New Source Performance Standard, 40 CFR 60, Subpart GG, Standard of Performance for Stationary Gas Turbines apply to combustion turbines constructed or modified after October 3, 1977, with heat input equal to or greater than 10 MMBtu/hr [40 CFR 60.330]. However, NSPS GG has been supplanted by a newer subpart (NSPS KKKK) that exempts subject units from NSPS GG [40 CFR 60.4305(b)]. The CCCTs at SJEC are subject to the requirements of NSPS KKKK and are, therefore, exempt from NSPS GG.

(f) The requirements of Standards of Performance for Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984, 40 CFR 60, Subpart Kb, regulates storage vessels with a capacity greater than 75 cubic meters (m^3) (19,813 gallons) that are used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984 [40 CFR 60.110b(a)]. The various lubrication oil, gasoline, and diesel storage tanks at the proposed CCCT Facility have capacities less than 19,813 gallons. Therefore, these storage tanks are not subject to the requirements of this subpart. The materials stored in the water treatment storage tanks (i.e., sulfuric acid solution, sodium hypochlorite solution, and ammonia

solution) do not meet the definition of a volatile organic liquids per 40 CFR 60.111b. Therefore, no tanks at the proposed SJEC Facility are subject to the requirements of NSPS Kb.

(g) The requirements of National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, 40 CFR 63, Subpart YYYY establishes emission and operating limitations for HAP emitted from stationary combustion turbines located at major sources of HAP emissions. SJEC will be an area source of HAP and as such is not subject to this standard.

(h) The requirements of National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers 40 CFR 63 Subpart Q for Industrial Process Cooling Towers, applies to cooling towers operating with chromium-based water treatment chemicals that are either major sources of HAP or are integral parts of a facility that is a major source of HAP. The only requirement for affected sources is to utilize water treatment chemicals that are not chromium based. The new cooling tower water treatment chemicals will not be chromium based, so this regulation will not apply to the proposed cooling towers.

(i) The requirements of Area Source MACT - National Emission Standards for Hazardous Air Pollutants – Industrial, Commercial, and Institutional Boilers at Area Sources 40 CFR Part 63 Subpart JJJJJJ regulates HAP emissions from industrial, commercial, and institutional boilers at area sources of HAP. Pursuant to 40 CFR 63.11195(e), gas-fired boilers are not subject to any requirements. Therefore, the proposed auxiliary boilers at SJEC will not have any applicable requirements under this standard.

(j) The requirements of the New Source Performance Standard, 40 CFR 60, Subpart Dc, Standard of Performance for Small -Commercial-Institutional Steam Generating Units, which is incorporated by reference as 326 IAC 12 NSPS, applies to steam generating units constructed or modified after June 9, 1989, with heat input equal to or greater than 10 MMBtu/hr but less than 100 MMBtu/hr [40 CFR 60.40c(a)]. A steam generating unit is defined as a device that combusts any fuel that is used to heat an indirect heat transfer medium [40 CFR 60.41c].

The proposed CCCT Facility will include auxiliary boilers with a maximum heat input capacity of 80 MMBtu/hr each. Since the auxiliary boilers combust natural gas to heat a heat transfer medium, the boilers meet the definition of steam generating units and are regulated by NSPS Dc.

The auxiliary boilers will fire only natural gas. Pursuant to 40 CFR 60.42c, NSPS Dc SO_2 emission limitations are not specified for affected sources that combust only natural gas (as defined in 40 CFR 60.41c). Similarly, pursuant to 40 CFR 60.43c, NSPS Dc PM emission limitations are not specified for affected sources that combust only natural gas. As such, NSPS Dc SO_2 and PM emission limitations do not apply to the auxiliary boilers.

Pursuant to 40 CFR 60.48c(g)(2), affected sources that combust only natural gas are required to record and maintain records of the amount of natural gas combusted during each calendar month. According to 40 CFR 60.48c(i), the monthly fuel usage records must be maintained for a minimum of two (2) years.

These emission units are subject to the following portions of Subpart Dc:

(1) Two (2) natural gas fired auxiliary boilers, identified as B001 and B002, permitted in 2012, each, with a maximum heat input capacity of 80 MMBtu/hr (HHV), equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stacks B001 and B002. Under 40 CFR Part 60, Subpart Dc, the auxiliary boiler is considered a steam generating unit.

The auxiliary boilers are subject to the following Sections of 40 CFR Part 60, Subpart Dc.

1. 40 CFR 60.40c(a)-(d)
2. 40 CFR 60.41c
3. 40 CFR 60.48c(a)(1), (3)
4. 40 CFR 60.48c(g),(i)

The provisions of 40 CFR 60 Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the facilities described in this section except when otherwise specified in 40 CFR 60 Subpart Dc.

(k) The requirements of 40 CFR, Subpart IIII - Standard of Performance for Stationary Compression Ignition Internal Combustion Engines 40 CFR 60, apply to owners or operators of stationary compression ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005, and that were manufactured after April 1, 2006, and are not fire pump engines, or were manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

SJEC proposes to install two nominal 371 bhp fire pump engines and two nominal 750 kW emergency generators that will combust ULSD that will be subject to the provisions of NSPS IIII. In addition, a nominal 1,500 kW emergency generator that will combust ULSD will be installed at the water treatment plant and will be subject to the provisions of this rule.

In accordance with 40 CFR 60.4205(b), owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 litres per cylinder that are not fire pumps must comply with the emission standards for new CI engines in 40 CFR 60.4202. In accordance with 40 CFR 60.4202(a)(2), engines manufactured after 2007 with displacement less than 10 litres per cylinder and with a maximum engine power greater than or equal to 37 kilowatts (kw) (50 bhp) and less than or equal to 2,237 kw (3,000 bhp) must comply with the certification emission standards in 40 CFR 89.112, Table 1 (Tier 2 requirements for engines > 560 kW after 2006), and the opacity standards in 40 CFR 89.113. Note that constant-speed engines are exempt from the opacity standards. As provided in 40 CFR 60.4211(c), to demonstrate compliance with these emission standards, SJEC will purchase an emergency generator certified to the Tier 2 emission limits, and install and configure the engine according to the manufacturer's specifications.

In accordance with 40 CFR 60.4205(c), owners and operators of fire pump engines with a displacement of less than 30 litres per cylinder must comply with the emission standards in Table 4 of NSPS IIII for all pollutants. As provided in 40 CFR 60.4211(c), to demonstrate compliance with these emission standards, SJEC will purchase a fire pump engine certified to the emission limits listed in Table 4 of NSPS IIII, and install and configure the engine according to the manufacturer's specifications.

Both the emergency generators and fire pumps must utilize nonroad diesel fuel with a sulfur content less than or equal to 15 parts per million (ppm). The fuel must also have either a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent (per 40 CFR 60.4207(b) and 40 CFR 80.510(b)).

These emission units are subject to the following portions of Subpart IIII:

(1) Two (2) firewater pump engines, each nominally rated at 371 brake horsepower (bph)and identified as FP01 and FP02, permitted in 2012, exhausting through two (2) vents, identified as FP01 and FP02, respectively. [Under 40 CFR 60, Subpart IIII, the firewater pump engines are considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the firewater pump engines are considered new affected sources.]

The firewater pump engines are subject to the following Sections of 40 CFR Part 60, Subpart IIII.

1. 40 CFR 60.4200(a)(2)(ii)
2. 40 CFR 60.4205(c)
3. 40 CFR 60.4206
4. 401 CFR 60.4207
5. 40 CFR 60.4211(a), (c)
6. 40 CFR 60.4218
7. 401 CFR 60.4219

These emission units are subject to the following portions of Subpart IIII:

(1) Two (2) emergency diesel generators, each nominally rated at 1,006 horsepower, identified as EG01 and EG02, permitted in 2012, exhausting through two (2) vents, identified as EG01 and EG02, respectively. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generators are considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generators are considered new affected source.]

(2) One (1) emergency diesel generator, nominally rated at 2012 horsepower, identified as EG03, permitted in 2012, exhausting through one (1) vent, identified as EG03. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generator is considered a new affected source.]

The emergency diesel generators are subject to the following Sections of 40 CFR Part 60, Subpart IIII.

1. 40 CFR 60.4200(a)(2)(i)
2. 40 CFR 60.4205(b)
3. 40 CFR 60.4206
4. 401 CFR 60.4207
5. 40 CFR 60.4211(a), (c)
6. 40 CFR 60.4218
7. 401 CFR 60.4219

The provisions of 40 CFR 60 Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the facilities described in this section except when otherwise specified in 40 CFR 60 Subpart IIII.

(l) The requirements of the New Source Performance Standard of Performance for Stationary Combustion Turbines, 40 CFR 60, Subpart KKKK applies to combustion turbines constructed, modified, or reconstructed after February 18, 2005, with heat input equal to or greater than 10 MMBtu/hr based on the higher heating value of the fuel [40 CFR 60.4305(a)]. The heat input from associated HRSGs and duct burners is not included in the applicability determination; however, the subpart applies to emissions from the combustion turbines, HRSGs, and duct burners if the heat input of the combustion turbines exceeds 10 MMBtu/hr. The proposed combustion turbines for SJEC have peak heat inputs greater than 10 MMBtu/hr. Therefore, the combustion turbines, HRSGs, and duct burners are subject to the requirements of 40 CFR 60, Subpart KKKK.

These emission units are subject to the following portions of Subpart KKKK:

(1) Four (4) natural gas-fired combined cycle combustion turbines, identified as units CCCT1, CCCT2, CCCT3, and CCCT4, permitted in 2012, each with a combustion turbine equipped with dry low NOx burners, natural gas fired duct burners, and a heat recovery steam generator identified as HRSG1, HRSG2, HRSG3, and HRSG4, NOx emissions controlled by four (4) selective catalytic

reduction (SCR) systems (SCR01, SCR02, SCR03 and SCR04), CO and VOC emissions controlled by oxidation catalyst systems (CAT01, CAT02, CAT03 and CAT04) and exhausting to stacks CCCT01, CCCT02, CCCT03, and CCCT04, respectively. Each stack has continuous emissions monitors (CEMS) for NOx and CO. The nominal heat input for each CCCT is 2,300 MMBtu/hr (higher heating value (HHV)). The combined nominal power output is 1,350 megawatts (MW).

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

The combustion turbines, HRSGs and duct burners are subject to the following Sections of 40 CFR Part 60, Subpart KKKK.

1. 40 CFR 60.4300
2. 40 CFR 60.4305
3. 40 CFR 60.4320
4. 40 CFR 60.4330(a)(1) or (2)
5. 40 CFR 60.4333
6. 40 CFR 60.4340(b)(1)
7. 40 CFR 60.4345
8. 40 CFR 60.4350(a)-(e), (f)(1)-(2), (h)
9. 40 CFR 60.4360
10. 40 CFR 60.4365
11. 40 CFR 60.4370(b), (c)
12. 40 CFR 60.4375(a)
13. 40 CFR 60.4380(b)
14. 40 CFR 60.4385(a), (c)
15. 40 CFR 60.4395
16. 40 CFR 60.4400(a), (b)(2), (b)(4)-(6)
17. 40 CFR 60.4405
18. 40 CFR 60.4415
19. 40 CFR 60.4420

The provisions of 40 CFR 60 Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the facilities described in this section except when otherwise specified in 40 CFR 60 Subpart KKKK.

(m) The requirements of National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (NESHAPs) (326 IAC 20 and 40 CFR Part 63 Subpart ZZZZ) apply to the emergency generators. These Standards apply to stationary reciprocating internal combusting engines (RICE) that are located at facilities that are major and area sources of HAPs. The specific facilities subject to this rule includes the following.

(1) Two (2) emergency diesel generators, each nominally rated at 1,006 horsepower, identified as EG01 and EG02, permitted in 2012, exhausting through two (2) vents, identified as EG01 and EG02, respectively. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generators are considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generators are considered new affected source.]

(1) One (1) emergency diesel generator, nominally rated at 2012 horsepower, identified as EG03, permitted in 2012, exhausting through one (1) vent, identified as EG03. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generator is considered a new affected source.]

These emission units are subject to the following portions of Subpart ZZZZ:

1. 40 CFR 63.6580
2. 40 CFR 63.6585(a), (c)-(d)
3. 40 CFR 63.6590(a)(2)(iii)
4. 40 CFR 63.6590(c)(1)
5. 40 CFR 63.6665
6. 40 CFR 63.6670
7. 40 CFR 63.6675

The provisions of 40 CFR 63 Subpart A – General Provisions, which are incorporated as 326 IAC 20-1-1, apply to the facilities described in this section except when otherwise specified in 40 CFR 63 Subpart ZZZZ.

(n) **40 CFR Part 68 Risk Management Program**
The Risk Management Program (RMP) in Section 112(r) of the 1990 Clean Air Act Amendments was established to prevent accidental releases of hazardous substances. Applicability of the RMP program is determined by comparing the quantity of each hazardous material stored in a vessel to the 112(r) threshold quantity.

There is a 112(r) threshold quantity for ammonia with a concentration of 20 percent or greater per 40 CFR 68.130. The proposed CCCT Facility will install and operate two (2) 30,000 gallon tanks storing a 19 percent ammonia solution. The CCCT Facility is not proposing to utilize any other 112(r) regulated substances. Therefore, the CCCT Facility is not subject to the requirements of the RMP program.

(o) **40 CFR Part 70 Title V Operating Permit Program**
40 CFR 70 establishes the federal Title V operating permit program. Indiana has incorporated the provisions of the federal program in 326 IAC 2-7. The major source thresholds with respect to the Indiana Title V operating permit program for sources in attainment areas are 10 tpy of a single HAP, 25 tpy of any combination of HAP, 100 tpy of a criteria pollutant, or 100,000 tpy of GHG, expressed as CO_2e.

With emissions greater than the major source thresholds for criteria pollutants and GHG, SJEC will require a Title V permit. Under this submittal, SJEC is requesting a combined Title V permit for the CCCT facility and the associated on-site water treatment plant.

(p) **40 CFR Part 72-78 Acid Rain Program**
The Acid Rain Program (ARP) found at 40 CFR 72-78 applies to utility units. A utility unit is defined as a unit owned or operated by a utility that serves a generator in any state that produces electricity for sale. The CCCTs at the proposed facility are utility units subject to the ARP. The proposed auxiliary boilers do not provide steam that subsequently generates electricity from the steam turbines; thus, the boilers cannot generate electricity for sale and are not subject to the ARP. The ARP requires pollutant monitors in addition to possession of SO_2 allowances for each ton of SO_2 emitted. Possession of the SO_2 allowances is not required until after the end of the year in which the SO_2 is emitted. Therefore, this source is subject to the requirements of 326 IAC 21 and shall submit an application for a significant permit modification for the incorporation of the requirements of 326 IAC 21. Operation of CCCT1 - CCCT4 shall not be permitted until the Acid Rain Permit has been issued.

(q) **40 CFR Part 82 Stratospheric Ozone Protection Regulations**
The requirements originating from Title VI of the Clean Air Act, entitled *Protection of Stratospheric Ozone*, are contained in 40 CFR 82. Subparts A through E and Subparts G through I of 40 CFR 82 are not applicable to SJEC. 40 CFR 82, Subpart F, *Recycling and Emissions Reduction*, potentially applies if the facility operates, maintains, repairs, services, or disposes of appliances that utilize Class I or Class II ozone depleting substances. Subpart F generally requires persons completing the repairs, service, or

disposal to be properly certified. All repairs, service, and disposal of ozone depleting substances from such equipment (air conditioners, refrigerators, etc.) at SJEC will be completed by a certified technician.

(r) Clean Air Interstate Rule (CAIR)
The four (4) natural gas-fired combined cycle combustion turbines identified as CCCT1 - CCCT4 and four (4) heat recovery steam generator identified as HRSG1, HRSG2, HRSG3, and HRSG4 are subject to the Clean Air Interstate Rule (CAIR) Nitrogen Oxides Annual, Sulfur Dioxide, and Nitrogen Oxides Ozone Season Trading Programs – CAIR Permit for CAIR Units Under 40 CFR 97 because the proposed CCCTs are serve a generator rated at 25 MW or more and will produce electricity for sale.

State Rule Applicability - Entire Source

326 IAC 2-2 (Prevention of Significant Deterioration)
This new stationary source is one of the 28 listed source categories and has potential to emit of at least one regulated pollutant greater than 100 tons per year. This source is a major source pursuant to 326 IAC 2-2 (PSD).

326 IAC 2-2-3 (PSD BACT: Control Technology Review Requirements)
Pursuant to PSD/Operating Permit T141-31003-00579 and 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD)), the Best Available Control Technologies (BACT) for the source shall be as follows:

Natural Gas-Fired Combined Cycle Combustion Turbines, identified as CCCT1 through CCCT4:

1. **The PM, PM_{10} and $PM_{2.5}$ emissions;**

   (a) The PM, PM_{10} and $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as CCCT1 -CCCT4 shall not exceed 18 lb/hour and 0.0078 lbs per MMBtu with duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

   (b) The PM, PM_{10} and $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as CCCT1 -CCCT4 shall not exceed 15 pounds per hour and 0.0065 lbs per MMBtu without duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

(2) The H_2SO_4 emissions from the combined cycle combustion turbines identified as CCCT1 -CCCT4 shall be limited by a fuel sulfur limit of 0.75 gr S/100 scf fuel.

(3) **The CO emissions;**

   (a) The CO emissions from the CCCTs shall be controlled by a catalytic oxidation

   (b) The CO emissions shall not exceed 2.0 ppmv @15% O2 based on a 3-hr average.

(4) The SO_2 emissions from the combined cycle combustion turbines identified as CCCT1 - CCCT4 shall be limited by a fuel sulfur limit of 0.75 gr S/100 scf fuel.

(5) **The VOC emissions;**

   (a) The VOC emissions from the CCCTs shall be controlled by a catalytic oxidation

   (b) The VOC emissions shall not exceed 2.0 ppmvd @15% O_2, with duct burners based on 3-hr average.

(c) The VOC emissions shall not exceed 1.0 ppmvd @15% O_2, without duct burners based on 3-hr average.

(6) **The NOx emissions;**

(a) The NOx emissions from the CCCTs shall be controlled by a Selective Catalytic Reduction and DLN Burners.

(b) The NOx emissions shall not exceed 2.0ppmv @15% O_2 with duct burners based on a 3-hr average.

(7) **The GHGs BACT for the Combined Cycle Combustion Turbines identified as CCCT1 - CCCT4 shall be as follows;**

(a) The net heat rate shall not exceed 7,646 Btu/kW-hr (HHV-net) for each CCCT block (ISO conditions, baseload operation without duct firing or inlet evaporative cooling, and not accounting for transformer losses).

(b) The total CO_2 emissions from all four CCCT blocks shall not exceed 4,736,936 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

Startup and Shutdown Limitations for Combined Cycle Combustion Turbines

(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 consecutive CEMS data points in compliance with the primary BACT limits.

(b) Steady-state operating condition shall be defined as the period of time that the combustion turbine is operating in dry low NOx (premix) mode and in compliance with the primary BACT limit.

(c) A shutdown is defined as operation beginning when the combustion turbine exits dry low-NOx (premix) mode and ending with termination of continuous fuel flow to each turbine.

(d) A startup/shutdown cycle is a pair of subsequent shutdown and startup events (i.e., one startup followed by one shutdown represents one startup/shutdown cycle).

(e) Unit Offline is represented by the Unit on-line Time being 0.

(f) 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.

(g) An event is defined as:

(1) exactly one (1) startup or exactly one (1) shutdown

For CO and NO_X, the source determined the worst-case operating scenario that results in the highest modeled impacts to be a cold start of the CCCTs. The modeled cold start emission rates are based on startup emission totals provided by the turbine vendor. Therefore, the source proposes to use the cold start emission totals, per CCCT as a short-term limit during startup/shutdown events, as follows:

CO - 2,125 lb/event

NOx - 443 lb/event

(h) The NO_X emissions from the combined cycle combustion turbines stacks shall not exceed 81.6 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.

(i) The CO emissions from the combined cycle combustion turbines stacks shall not exceed 407.5 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.

(j) The VOC emissions from the combined cycle combustion turbines stacks shall not exceed 22.0 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.

Natural Gas-Fired Auxiliary Boilers, identified as B001 - B002:

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Auxiliary Boilers, identified as B001-B002 shall not exceed 0.0075 lb/MMBtu (HHV) and 0.6 lbs/hour, each, based on a 3-hr average period through the use of good combustion practices and fuel specification.

(2) The CO emissions from the Auxiliary Boilers (B001-B002) operation shall not exceed 0.083 lb/MMBtu (HHV) and 6.64 lbs/hr, each, based on a 3 - hour average through Good Combustion Practices.

(3) The SO_2 emissions from the Auxiliary Boilers, identified as B001-B002 shall not exceed 0.0022 lb/MMBtu (HHV) and 0.176 lbs/hr, each, based on a 3-hr average through the use of fuel specification.

(4) The VOC emissions from the Auxiliary Boilers, identified as B001-B002 shall not exceed 0.005 lb/MMBtu (HHV) and 0.4 lbs/hr, each, based on a 3-hr average period through the use of good combustion practices.

(5) **The NOx emissions;**

(a) The NOx emissions from the Auxiliary Boilers, identified as B001-B002 shall be controlled by Low NOx Burners with Flue Gas Recirculation.

(b) The NOx emissions shall not exceed 0.032 lb/MMBtu (HHV) and 2.56 pounds per hour each, based on a 3-hr average period.

(6) The GHGs BACT for the Auxiliary Boilers, identified as B001-B002 shall be as follows

(a) Operating and Maintenance (O&M) Practices;

(b) Combustion Turning;

(c) The boiler will be equipped with oxygen trim controls and oxygen analyzers;

(d) The boiler will be equipped with an economizer;

(e) Energy efficient refractory will be installed;

(f) The boiler will be equipped with a condensate return system (recovery);

(g) Steam and hot lines will be insulated;

(h) Boiler designed for 80% thermal efficiency (HHV); and

(i) The total CO_2 emissions from the two auxiliary boilers shall be limited to less than 81,996 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

Firewater Pump Engines, identified as FP01 - FP02:

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Firewater Pump Engines identified as FP01 - FP02 shall be limited to less than 0.15 g/hp-hr through the use of combustion design control and usage limitation.

(2) The CO emissions from the Firewater Pump Engines identified as FP01 - FP02 shall not exceed 2.6 g/hp-hr through the use of combustion design control and usage limitation.

(3) The SO_2 emissions from the Firewater Pump Engines identified as FP01 - FP02 shall not exceed 0.0015 % S and 0.043 lb/hr, each through the use of ultra low sulfur distillate (ULSD) and usage limitation.

(4) The VOC emissions from the Firewater Pump Engines identified as FP01 - FP02 shall not exceed 0.16 pounds per hour,each through the use of Combustion Design Controls and usage limitation.

(5) The NOx emissions from the Firewater Pump Engines identified as FP01 - FP02 shall not exceed 3.0 g/bhp-hr for NOx + NMHC through the use of Combustion Design Controls and usage limitation.

(6) The GHGs BACT for the Firewater Pump Engines identified as FP01 - FP02 shall be as follows;

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

(B) The total CO_2 emissions from the two (2) firewater pump engines shall not exceed 172 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

(7) The Firewater Pumps identified as FP01 - FP02 shall not exceed 500 hours per year, each.

Emergency Diesel Generators, identified as (EG01 - EG03):

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Emergency Generators, Identified as EG01, EG02 and EG03 shall not exceed 0.15 g/hp-hr, each through the use of combustion design control and usage limitation.

(2) The CO emissions from the Emergency Diesel Generators, Identified as EG01, EG02 and EG03 shall not exceed 2.6 g/hp-hr, each through the use of combustion design controls and usage limitation.

(3) The SO_2 emissions from the Emergency Diesel Generators, Identified as EG01 and EG02 shall not exceed 0.012 lb/hr through the use of ultra low sulfur distillate (ULSD) and usage limitation.

(4) The SO_2 emissions from the Emergency Diesel Generator, Identified as EG03 shall not exceed 0.024 lb/hr through the use of ultra low sulfur distillate (ULSD) and usage limitation.

(5) The VOC emissions from the Emergency Diesel Generators, Identified as EG01 and EG02 shall not exceed 1.04 lbs/hr, each, through the use of Combustion Design Controls and usage limitation.

(6) The VOC emissions from the Emergency Diesel Generator, Identified as EG03 shall not exceed 1.04 lbs/hr through the use of Combustion Design Controls and usage limitation.

(7) The NOx emissions from the Emergency Diesel Generators shall not exceed 4.8 g/bhp-hr for NOx + NMHC through the use of Combustion Design Controls and usage limitation.

(8) The GHGs BACT for the Emergency Diesel Generators, Identified as EG01, EG02 and EG03 shall be as follows

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

(2) The total CO_2 emissions from all the three (3) emergency diesel generators shall not exceed 1,186 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

(9) The Emergency Diesel Generators, Identified as EG01, EG02 and EG03 shall not exceed 500 hours per year, each.

Cooling Tower CT01-CT02:

The PM, PM_{10} and $PM_{2.5}$ emissions from the Cooling Towers, identified as CT01 and CT02 shall be controlled by High efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.

Turbine Lube Oil Demister Vents DM01 – DM06:

1. The VOC emissions from the Turbine Lube Oil Demister Vents, identified as DM01 – DM06 shall be the use of good design and operating practices.

2. The organic PM, PM_{10} and $PM_{2.5}$ emissions from the Turbine Lube Oil Demister Vents, identified as DM01 – DM06, shall be the use of good design and operating practices.

Storage Tanks TK01-TK10, TK12 and TK50:

The VOC emissions from the Turbine Lube Oil storage tanks, identified as TK01 - TK06, and Diesel Storage Tanks, identified as TK07, TK08, TK09, TK10, TK12 and TK50 shall be limited by the use of good design and operating practices.

Gasoline Dispensing Storage Tank TK11:

The VOC emissions from the Vehicle Gasoline Dispensing Operation, identified as TK11 shall be limited by the use of submerged fill pipes and Stage I vapor control.

Electric Circuit Breaker (FUG-SF6):

(1) The use of totally enclosed pressure system with a design leak rate of 0.5% and a density alarm for leak detection.

(2) The total SF_6 emissions from all the circuit breakers shall not exceed 0.0009 tons of SF_6 per twelve (12) consecutive month period with compliance determined at the end of the month.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The operation of these emission units in the plant 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 1-7 (Actual Stack Height Provisions)
The stack height provisions in this rule apply to sources for which construction commenced after June 19, 1979 and that emit SO_2 or PM emissions in levels greater than 25 tons per year. The combined cycle combustion turbine stacks, are subject to these requirements. As such, these stacks are subject to the height provisions listed in 326 IAC 1-7-3, which prohibits excessive concentrations of PM and SO_2.

326 IAC 2-6 (Emission Reporting)
This source is subject to 326 IAC 2-6 (Emission Reporting) because it is required to have an operating permit pursuant to 326 IAC 2-7 (Part 70). The potential to emit of PM_{10} is greater than 250 tons per year. Therefore, pursuant to 326 IAC 2-6-3(a)(1), annual reporting is required. An emission statement shall be submitted each year by July 1. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4.

326 IAC 5-1 (Opacity Limitations)
This source is subject to the opacity limitations specified in 326 IAC 5-1-2(1)

326 IAC 6.5 PM Limitations Except Lake County
This source is subject to 326 IAC 6.5 because it is located in St. Joseph County, its PM PTE (or limited PM PTE) is equal to or greater than 100 tons per year or actual emissions are greater than 10 tons per year. However, this source is not one of the sources specifically listed in 326 IAC 6.5-2 through 326 IAC 6.5-10. Therefore, 326 IAC 6.5-1-2(a) applies. Applicability for individual facilities is noted is noted in subsequent sections.

326 IAC 6-4 (Fugitive Dust Emissions)
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 6-5 (Fugitive Particulate Matter Emission Limitations)
The source is not subject to the requirements of 326 IAC 6-5 because the amounts of fugitive particulate matter emissions from paved roadways are less than 25 tons per year.

State Rule Applicability – Individual Facilities

326 IAC 3-5 (Continuous Monitoring of Emissions)
The natural gas-fired combined cycle combustion turbine, identified as units CCCT1, CCCT2, CCCT3, and CCCT4 are subject to the monitoring requirements of 326 IAC 3-5 because they are fossil fuel fired steam generators that have a heat input capacity of greater than 100 MMBtu per hour, each.

Pursuant to 326 IAC 3-5-1(b)(2)(C) and 326 IAC 3-5-1(a)(1), a continuous monitoring system shall be installed, calibrated, operate and maintain Nitrogen Oxide (NOx) for each of the stacks, CCCT01, CCCT02, CCCT03, and CCCT04 in accordance with 326 IAC 3-5-2 and 326 IAC 3-5-3.

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 limitation 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 limitation 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 6.5 Particulate Matter Limitations Except Lake County

(a) Pursuant to 326 IAC 6.5-1-1(b), this rule does not apply to the CTs, duct burners, and auxiliary boilers as these units combust only natural gas.

(b) Pursuant to 326 IAC 6.5-1-1(c), this rule does not apply to the firewater pumps and emergency generators as they are subject to more stringent particulate matter limits under NSPS IIII.

(c) Pursuant to 326 IAC 6.5-1-2(a), the particulate emission from the lime silos and demister vents shall not exceed 0.03 grains per dry standard cubic feet (gr/dscf).

326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating)

Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating: Emission Limitations for facilities specified in 326 IAC 6-2-1(d)), the PM emissions from the auxilliary boilers, identified as B001 and B002 and the duct burners shall not exceed 0.2 pounds per million Btu heat input (lb/MMBtu), each. This limitation was calculated using the following equation:

$$Pt = \frac{1.09}{Q^{0.26}}$$

Where:

Q = total source heat input capacity (MMBtu/hr).
For these units, Q = 748.0 MMBtu/hr.

However, 326 IAC 6-2-1(h) states that if a limitation established by this rule is inconsistent with a limitation required by the permit regulations, then the permit regulation limit will prevail. Since the BACT emissions limit is significantly more stringent than the above calculated limit, compliance with the BACT particulate matter limits renders the above rule 326 IAC 6-2-4 not applicable to these auxiliary boilers.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)

Pursuant to 326 IAC 6-3-1(c), the particulate emission limitations for manufacturing processes contained in 326 IAC 6-3 do not apply to any of the emission units because particulate matter emission limitations established under 326 IAC 2-2-3 (PSD) are more stringent and are exempt from the requirements of this rule.

326 IAC 7-1.1 Sulfur Dioxide Emission Limitations

(a) The emergency diesel generators and firewater pump engines are not subject to the requirements of 326 IAC 7-1.1 because each of them has the potential to emit SO_2 emissions less than 25 tons per year.

(b) The potential to emit SO_2 emissions from each of the heat recovery steam generators (HRSG1 through HRSG4) is less than 25 tons per year. Therefore, these units are not subject to the requirements of 326 IAC 7-1.1.

(c) The potential to emit SO_2 emissions from each of the combined cycle combustion turbines, identified as CCCT1, CCCT2, CCCT3, and CCCT4 is less than 25 tons per year. Therefore, these units are not subject to the requirements of 326 IAC 7-1.

326 IAC 8-1-6 (New facilities; general reduction requirements)

(a) Each of the heat recovery steam generators with duct burners (HRSG1 through HRSG4) at this source was constructed after January 1, 1980 and has potential VOC emissions less than 25 tons per year. Therefore, the requirements of 326 IAC 8-1-6 (BACT) are not applicable to these units.

(b) The two (2) auxiliary boilers were constructed after January 1, 1980 and have potential VOC emissions less than 25 tons per year, each. Therefore, the requirements of 326 IAC 8-1-6 (BACT) are not applicable to these boilers.

(c) Each of the combustion turbines at this source was constructed after January 1, 1980 and has potential VOC emissions less than 25 tons per year. Therefore, the requirements of 326 IAC 8-1-6 (BACT) are not applicable to these combustion turbines.

326 IAC 8-3-2 (Cold Cleaner Operations)
The cold cleaning operations are subject to 326 IAC 8-3-2 (Cold Cleaner Operations). This rule applies to cold cleaner type degreasing facilities constructed after January 1, 1980. The cold cleaning operations at this source were constructed after 1980; therefore, the requirements of 326 IAC 8-3-2 shall apply to these facilities.

326 IAC 8-3-5 (Cold Cleaner Degreaser Operation and Control)
The cold cleaning operations are subject to 326 IAC 8-3-5 (Cold Cleaner Degreaser Operation and Control). This rule applies to cold cleaner type degreasing facilities constructed after July 1, 1990. The cold cleaning operations at this source were constructed after to 1990, and do not have remote solvent reservoirs, therefore, the requirements of 326 IAC 8-3-5 shall apply to these facilities.

326 IAC 8-4-6 (Gasoline Dispensing Facilities)
The gasoline dispensing storage tank with storage capacity greater than five hundred seventy five (575) gallons is subject to this rule. However the gasoline dispensing tank is subject to requirements 326 IAC 2-2-3 (PSD). Therefore, compliance with requirements of 326 IAC 2-2-3 will satisfy the requirements of 326 IAC 8-4-6.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
This source is subject to 326 IAC 9-1 because it is a stationary source of CO emissions commencing operation after March 21, 1972 and has CO emissions of more than 100 tons per year. There are no applicable CO emission limits, under this state rule, established for this type of operation and the source is not proposing to install any of the source types regulated under this rule at the CCCT Facility.

326 IAC 2-2-4 (Air Quality Analysis Requirements)
Section (4)(a) of this rule, requires that the PSD application shall contain an analysis of ambient air quality in the area that the major stationary source would affect for pollutants that are emitted at major levels or significant amount. St. Joseph Energy Center, LLC has submitted an air quality analysis, which has been evaluated by IDEM's Technical Support and Modeling Section. See details in Appendix C.

NAAQs modeling for the appropriate time-averaging periods was conducted. OAQ modeling results are shown in Appendix C. All maximum-modeled concentrations were compared to the respective NAAQS limit. All maximum-modeled concentrations during the five years were below the NAAQS limit except for the 24-hour $PM_{2.5}$ and a culpability analysis was required and is shown in Table 6 of Appendix C. Results were based from worst operating scenario determined in SIA modeling.

326 IAC 2-2-5 (Air Quality Impact Requirements)
326 IAC 2-2-5(e)(1) of this rule, requires that the air quality impact analysis required by this section shall be conducted in accordance with the following provisions:

(1) Any estimates of ambient air concentrations used in the demonstration processes required by this section shall be based upon the applicable air quality models, data bases, and other requirements specified in 40 CFR Part 51, Appendix W (Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Guideline on Air Quality Models)*.

(2) Where an air quality impact model specified in the guidelines cited 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 public comment procedures set forth in 326 IAC 2-1.1-6.

Economic Growth
The purpose of the growth analysis is to quantify project associated growth and estimate the air quality impacts from this growth either quantitatively or qualitatively.

It is estimated that 23 additional jobs will be created as a result of the proposed project. Most of the employees will be drawn from nearby areas. Since the area is predominately rural, it is not expected the growth impacts will cause a violation of the NAAQs or the PSD increment.

Soils and Vegetation Analysis
Soil types included a variety of loamy soils. Due to the agricultural nature of the land, crops in the St. Joseph County area consist mainly of corn and soybeans. (2007 Agricultural Census for St. Joseph County). The maximum modeled concentrations for SJEC are well below the threshold limits necessary to have adverse impacts on the surrounding vegetation. Livestock in St. Joseph County consist mainly of hogs, cattle and dairy (2007 Agricultural Census for St. Joseph County) and will not be adversely impacted from the facility. Trees in the area are mainly hardwoods. These are hardy trees and no significant adverse impacts are expected due to modeled concentrations.

Federal and State Endangered Species Analysis
Federal and state endangered species are listed by the U.S. Fish and Wildlife Service; Division of Endangered Species for Indiana, and include 5 amphibians, 27 birds, 10 fishes, 7 mammals, 15 mollusks, and 15 reptiles. Of the federal and state endangered species on the list, 5 reptiles, 3 mollusks, 1 fish, 1 insect, 18 birds, 3 amphibians and 7 mammals have habitat within St. Joseph County. The mollusks, fish, amphibians, and certain species of birds and mammals are found along rivers and lakes while the other species of birds and mammals are found in forested areas. The facility is not expected to have any additional adverse effects on the habitats of the species than what has already occurred from the industrial, farming, and residential activities in the area.

Federal and state endangered plants are listed by the U.S. Fish and Wildlife Service, Division of Endangered Species for Indiana. At this time 27 state endangered plant species (including the Goose-foot Corn-salad and Running Serviceberry) are found in St. Joseph County. The endangered plants do not thrive in industrialized and residential areas. The facility is not expected to adversely affect any plant on the endangered species list.

326 IAC 2-2-6 (Increment Consumption Requirements)
326 IAC 2-2-6(a) requires that any demonstration under section 5 of this rule shall demonstrate that increased emissions caused by the proposed major stationary source will not exceed eighty percent (80%) of the available maximum allowable increases (MAI) over the baseline concentration of sulfur dioxide, particulate matter, and nitrogen dioxide indicated in subsection (b)(1) of this rule.

326 IAC 2-2-7 (Additional Analysis, Requirements)
326 IAC 2-2-7(a) requires an analysis of the impairment to visibility, soils and vegetation. An analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the source was performed. See detailed analysis in Appendix C.

326 IAC 2-2-8 (Source Obligation)
(1) Pursuant to 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.

(2) 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.

326IAC 2-2-10 (Source Information)
The Permittee has submitted all information necessary to perform an analysis or make the determination required under this rule.

326 IAC 2-2-12 (Permit Rescission)
The permit issued under this rule shall remain in effect unless and until it is rescinded, modified, revoked, or it expires in accordance with 326 IAC 2-1.1-9.5 or section 8 of this rule.

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to ensure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions; however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

The compliance determination and monitoring requirements applicable to this modification are as follows:

Testing Requirements

(a) Testing Requirements

Emission units	Control device	When to test	Pollutants	Frequency of testing	Limit or Requirement
CCCT1, CCCT2, CCCT3, and CCCT4	With Duct Burner Without Duct Burner	60 days / no later than 180 days	PM, PM_{10} and $PM_{2.5}$	5 year	326 IAC 2-2-3
CCCT1, CCCT2, CCCT3, and CCCT4	Oxidation Catalyst with Duct Burner Oxidation Catalyst without Duct Burner	60 days / no later than 180 days	VOC	5 year	326 IAC 2-2-3
CCCT1, CCCT2, CCCT3, and CCCT4	No control	60 days / no later than 180 days	CO_2 (Heat Rate Performance)	5 year	326 IAC 2-2-3
Auxiliary Boiler	No Control	60 days / no later than 180 days	PM, PM_{10} and $PM_{2.5}$	One time testing	326 IAC 2-2-3
Auxiliary Boiler	No Control	60 days / no later than 180 days	VOC	One time testing	326 IAC 2-2-3
Auxiliary Boiler	Low NOx Burner with Flue Gas Recirculation	60 days / no later than 180 days	NOx	5 year	326 IAC 2-2-3
Auxiliary Boiler	No Control	60 days / no later than 180 days	CO	One time testing	326 IAC 2-2-3
Auxiliary Boiler	No control	60 days / no later than 180 days	Thermal Efficiency	one time testing	326 IAC -2-2-3

Note: Compliance with the NOx and CO emission limits for the combustion turbines are demonstrated by using the NOx and CO CEMs data.

No stack testing are required for the emergency diesel generators and the firewater pump engines because these units are emergency use units and/or insignificant activities and compliance with the BACT limits are demonstrated through keeping records of the fuel used. Operations of the high efficiency drift eliminators at all times will ensure compliance with $PM/PM_{10}/PM_{2.5}$ limit for the insignificant cooling towers. Therefore, no testing is required for the cooling towers.

(b) The compliance monitoring requirements applicable to this source are as follows:

Control	Parameter	Frequency	Range/ Value	Excursions and Exceedances	Limit or Requirement
Oxidation Catalyst	Temperature	Continuous	Value provided by catalyst vendor or as determined from the last compliance stack test	Response steps	326 IAC 2-2-3

(c) The compliance monitoring requirements applicable to this source are as follows:

Control	Parameter	Frequency	Value	Excursions and Exceedances	Requirement
CCCT1, CCCT2, CCCT3, and CCCT4 (SCR with DLN)	NOx CEMS	Continuous	N/A	Continuous emission monitoring system measurement data.	326 IAC 2-2-3
CCCT1, CCCT2, CCCT3, and CCCT4 (Oxidation Catalyst)	CO CEMS	Continuous	N/A	Continuous emission monitoring system measurement data.	326 IAC 2-2-3

Recommendation

The staff recommends to the Commissioner that the Part 70 Operating Permit be approved. This recommendation is based on the following facts and conditions:

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant.

An application for the purposes of this review was received on October 3, 2011.

Conclusion

The operation of this power plant shall be subject to the conditions of the attached Part 70 Operating Permit No. 141-31003-00579.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to Josiah Balogun at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) 234-5257 or toll free at 1-800-451-6027 extension 4-5257.

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

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM's Guide for Citizen Participation and Permit Guide on the Internet at: www.idem.in.gov.

Appendix A: Emissions Calculations
Emission Summary
Source Name: St. Joseph Energy Center, LLC
Source Location: Coner of Walnut and Edison Roads, New Calisle, IN 46552
Permit Number: 141-31003-00579
Permit Reviewer: Josiah Balogun
Date: 2-Nov-2011

Uncontrolled Potential to Emit

	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	H_2SO_4 (tons/yr)	NH_3 (tons/yr)	SF_6 (tons/yr)	CH_4 (tons/yr)	N_2O (tons/yr)	CO_2 (tons/yr)	GHGs as CO_2e (tons/yr)	HAPs (tons/yr)
Emission Unit															
Combustion Turbine CCCT1	78.84	78.84	78.84	24.97	33.29	242.65	359.16	19.69	69.42	0.00	21.74	2.17	1183104	1184234	4.15
Combustion Turbine CCCT2	78.84	78.84	78.84	24.97	33.29	242.65	359.16	19.69	69.42	0.00	21.74	2.17	1183104	1184234	4.15
Combustion Turbine CCCT3	78.84	78.84	78.84	24.97	33.29	242.65	359.16	19.69	69.42	0.00	21.74	2.17	1183104	1184234	4.15
Combustion Turbine CCCT4	78.84	78.84	78.84	24.97	33.29	242.65	359.16	19.69	69.42	0.00	21.74	2.17	1183104	1184234	4.15
Aux. Boiler B001	2.63	2.63	2.63	0.77	1.75	28.91	10.99	0.00	0.00	0.00	0.77	0.08	40,958	40998	0.3
Aux. Boiler B002	2.63	2.63	2.63	0.77	1.75	28.91	10.99	0.00	0.00	0.00	0.77	0.08	40,958	40998	0.3
Cooling Tower CT01	3.73	2.37	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower CT02	3.73	2.37	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Firewater pump FP01	0.03	0.03	0.03	0.19	0.03	0.43	0.5	0.00	0.00	0.00	0.003	0.001	86	86	0.0025
Firewater Pump FP02	0.03	0.03	0.03	0.19	0.03	0.43	0.5	0.00	0.00	0.00	0.003	0.001	86	86	0.0025
Emergency Gen. EG01	0.08	0.08	0.08	0.00	0.05	1.45	2.65	0.00	0.00	0.00	0.01	0.002	299	300	0.003
Emergency Gen. EG02	0.08	0.08	0.08	0.00	0.05	1.45	2.65	0.00	0.00	0.00	0.01	0.002	299	300	0.003
Emergency Gen. EG03	0.03	0.03	0.03	0.01	0.12	0.49	0.64	0.00	0.00	0.00	0.02	0.005	584	586	0.01
Turbine Lube Oil Demister Vent DM01-DM06	0.35	0.35	0.35	0.00	0.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Storage Tanks	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Six (6) Circuit Breakers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0009	0.00	0.00	0.00	22	0.00
Two (2) Lime Silos	0.66	0.31	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Emissions	329.34	326.27	321.29	101.81	137.40	1032.67	1465.56	78.76	277.68	0.0009	88.55	8.85	4815686	4820312	17.22

Appendix A: Emissions Calculations
Emission Summary
Source Name: St. Joseph Energy Center, LLC
Source Location: Coner of Walnut and Edison Roads, New Calisle, IN 46552
Permit Number: 141-31003-00579
Permit Reviewer: Josiah Balogun
Date: 2-Nov-2011

Limited Potential to Emit

	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	H_2SO_4 (tons/yr)	NH_3 (tons/yr)	SF_6 (tons/yr)	CH_4 (tons/yr)	N_2O (tons/yr)	CO_2 (tons/yr)	GHGs as CO_2e (tons/yr)	HAPs (tons/yr)
Emission Unit															
Combustion Turbine CCCT1	78.84	78.84	78.84	24.97	24.97	130.03	71.83	19.69	69.42	0.00	21.74	2.17	1183104	1184234	3.09
Combustion Turbine CCCT2	78.84	78.84	78.84	24.97	24.97	130.03	71.83	19.69	69.42	0.00	21.74	2.17	1183104	1184234	3.09
Combustion Turbine CCCT3	78.84	78.84	78.84	24.97	24.97	130.03	71.83	19.69	69.42	0.00	21.74	2.17	1183104	1184234	3.09
Combustion Turbine CCCT4	78.84	78.84	78.84	24.97	24.97	130.03	71.83	19.69	69.42	0.00	21.74	2.17	1183104	1184234	3.09
Aux. Boiler B001	2.63	2.63	2.63	0.77	1.75	28.91	10.99	0.00	0.00	0.00	0.77	0.08	40,958	40998	0.3
Aux. Boiler B002	2.63	2.63	2.63	0.77	1.75	28.91	10.99	0.00	0.00	0.00	0.77	0.08	40,958	40998	0.3
Cooling Tower CT01	3.73	2.37	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower CT02	3.73	2.37	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Firewater pump FP01	0.03	0.03	0.03	0.19	0.03	0.43	0.5	0.00	0.00	0.00	0.003	0.001	86	86	0.0025
Firewater Pump FP02	0.03	0.03	0.03	0.19	0.03	0.43	0.5	0.00	0.00	0.00	0.003	0.001	86	86	0.0025
Emergency Gen. EG01	0.08	0.08	0.08	0.00	0.05	1.45	2.65	0.00	0.00	0.00	0.01	0.002	299	300	0.003
Emergency Gen. EG02	0.08	0.08	0.08	0.00	0.05	1.45	2.65	0.00	0.00	0.00	0.01	0.002	299	300	0.003
Emergency Gen. EG03	0.03	0.03	0.03	0.01	0.12	0.49	0.64	0.00	0.00	0.00	0.02	0.005	584	586	0.01
Turbine Lube Oil Demister Vent DM01-DM06	0.35	0.35	0.35	0.00	0.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Storage Tanks	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Six (6) Circuit Breakers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0009	0.00	0.00	0.00	22	0.00
Two (2) Lime Silos	0.11	0.11	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Emissions	328.79	326.07	321.35	101.81	104.12	582.19	316.24	78.76	277.68	0.0009	88.55	8.85	4815686	4820312	12.98

Emission Calculations

Facility Wide Potential Emissions Summary

Pollutant	CCCT1 (tpy)	CCCT2 (tpy)	CCCT3 (tpy)	CCCT4 (tpy)	B001 (tpy)	B002 (tpy)	CT01 (tpy)	CT02 (tpy)	EG01 (tpy)	EG02 (tpy)	EG03 (tpy)	FP01 (tpy)	FP02 (tpy)	DM01-DM06 (tpy)	Storage Tanks (tpy)	Lime Silo (tpy)	Circuit Breakers (tpy)	Facility Wide Total (tpy)
CO	130.03	130.03	130.03	130.03	28.91	28.91	-	-	1.45	1.45	0.49	0.43	0.43	-	-	-	-	582.18
NO_X	71.83	71.83	71.83	71.83	10.99	10.99	-	-	2.65	2.65	0.64	0.50	0.50	-	-	-	-	316.25
TSP	78.84	78.84	78.84	78.84	2.63	2.63	3.73	3.73	0.08	0.08	0.03	0.03	0.03	0.35	-	0.11	-	328.78
Total PM_{10}	78.84	78.84	78.84	78.84	2.63	2.63	2.37	2.37	0.08	0.08	0.03	0.03	0.03	0.35	-	0.11	-	326.06
Total $PM_{2.5}$	78.84	78.84	78.84	78.84	2.63	2.63	0.01	0.01	0.08	0.08	0.03	0.03	0.03	0.35	-	0.11	-	321.34
SO_2	24.97	24.97	24.97	24.97	0.77	0.77	-	-	0.00	0.00	0.01	0.19	0.19	-	-	-	-	101.80
VOC	24.97	24.97	24.97	24.97	1.75	1.75	-	-	0.05	0.05	0.12	0.03	0.03	0.35	0.11	-	-	104.11
H_2SO_4	19.69	19.69	19.69	19.69	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	78.78
Fluorides (Other than HF)	0.00	0.00	0.00	0.00	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	0.00
NH_3	69.42	69.42	69.42	69.42	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	277.69
CO_2	1,183,104	1,183,104	1,183,104	1,183,104	40,958	40,958	-	-	299	299	584	86	86	-	-	-	-	4,815,684.96
CH_4	21.74	21.74	21.74	21.74	0.77	0.77	-	-	0.01	0.01	0.02	0.003	0.003	-	-	-	-	88.54
N_2O	2.17	2.17	2.17	2.17	0.08	0.08	-	-	0.002	0.002	0.005	0.001	0.001	-	-	-	-	8.86
SF_6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0009	0.0009
CO_2e	1,184,234	1,184,234	1,184,234	1,184,234	40,998	40,998	-	-	300	300	586	86	86	-	-	-	22	4,820,312.50

1. TSP emissions are only filterable PM emissions.

2. PM_{10} and $PM_{2.5}$ emissions are estimated as total particulate emissions (filterable + condensable).

Emission Calculations

Facility Wide Potential HAP Emissions Summary

Pollutant	CCCT1 (tpy)	CCCT2 (tpy)	CCCT3 (tpy)	CCCT4 (tpy)	B001 (tpy)	B002 (tpy)	CT01 (tpy)	CT02 (tpy)	EG01 (tpy)	EG02 (tpy)	EG03 (tpy)	FP01 (tpy)	FP02 (tpy)	DM01-DM06 (tpy)	Storage Tanks (tpy)	Lime Silo (tpy)	Circuit Breakers (tpy)	CCCT Plant Total (tpy)
1,3-Butadiene	4.43E-04	4.43E-04	4.43E-04	4.43E-04	-	-	-	-	-	-	-	2.54E-05	2.54E-05	-	-	-	-	1.82E-03
2-Methylnaphthalene	-	-	-	-	3.76E-06	3.76E-06	-	-	-	-	-	-	-	-	-	-	-	7.53E-06
3-Methylchloranthrene	-	-	-	-	2.82E-07	2.82E-07	-	-	-	-	-	-	-	-	-	-	-	5.65E-07
7,12-Dimethylbenz(a)anthracene	-	-	-	-	2.51E-06	2.51E-06	-	-	-	-	-	-	-	-	-	-	-	5.02E-06
Acenaphthene	-	-	-	-	2.82E-07	2.82E-07	-	-	8.24E-06	8.24E-06	1.65E-05	9.22E-07	9.22E-07	-	-	-	-	3.54E-05
Acenaphthylene	-	-	-	-	2.82E-07	2.82E-07	-	-	1.62E-05	1.62E-05	3.25E-05	3.29E-06	3.29E-06	-	-	-	-	7.21E-05
Acetaldehyde	3.15E-01	3.15E-01	3.15E-01	3.15E-01	-	-	-	-	4.44E-05	4.44E-05	8.87E-05	4.98E-04	4.98E-04	-	-	-	-	1.26E+00
Acrolein	4.10E-02	4.10E-02	4.10E-02	4.10E-02	-	-	-	-	1.39E-05	1.39E-05	2.77E-05	6.01E-05	6.01E-05	-	-	-	-	1.64E-01
Anthracene	-	-	-	-	3.76E-07	3.76E-07	-	-	2.16E-06	2.16E-06	4.33E-06	1.21E-06	1.21E-06	-	-	-	-	1.18E-05
Arsenic	-	-	-	-	3.14E-05	3.14E-05	-	-	-	-	-	-	-	-	-	-	-	6.27E-05
Beryllium	-	-	-	-	1.88E-06	1.88E-06	-	-	-	-	-	-	-	-	-	-	-	3.76E-06
Benzene	9.56E-02	9.56E-02	9.56E-02	9.56E-02	3.29E-04	3.29E-04	-	-	1.37E-03	1.37E-03	2.73E-03	6.06E-04	6.06E-04	-	-	-	-	3.90E-01
Benz(a)anthracene	-	-	-	-	2.82E-07	2.82E-07	-	-	1.09E-06	1.09E-06	2.19E-06	1.09E-06	1.09E-06	-	-	-	-	7.13E-06
Benzo(a)pyrene	-	-	-	-	1.88E-07	1.88E-07	-	-	4.52E-07	4.52E-07	9.05E-07	1.22E-07	1.22E-07	-	-	-	-	2.43E-06
Benzo(b)fluoranthene	-	-	-	-	2.82E-07	2.82E-07	-	-	1.95E-06	1.95E-06	3.91E-06	6.43E-08	6.43E-08	-	-	-	-	8.51E-06
Benzo(g,h,i)perylene	-	-	-	-	1.88E-07	1.88E-07	-	-	9.79E-07	9.79E-07	1.96E-06	3.17E-07	3.17E-07	-	-	-	-	4.93E-06
Benzo(k)fluoranthene	-	-	-	-	2.82E-07	2.82E-07	-	-	3.84E-07	3.84E-07	7.67E-07	1.01E-07	1.01E-07	-	-	-	-	2.30E-06
Cadmium	-	-	-	-	1.73E-04	1.73E-04	-	-	-	-	-	-	-	-	-	-	-	3.45E-04
Chromium	-	-	-	-	2.20E-04	2.20E-04	-	-	-	-	-	-	-	-	-	-	-	4.39E-04
Chrysene	-	-	-	-	2.82E-07	2.82E-07	-	-	2.69E-06	2.69E-06	5.39E-06	2.29E-07	2.29E-07	-	-	-	-	1.18E-05
Cobalt	-	-	-	-	1.32E-05	1.32E-05	-	-	-	-	-	-	-	-	-	-	-	2.64E-05
Dibenzo(a,h)anthracene	-	-	-	-	1.88E-07	1.88E-07	-	-	6.09E-07	6.09E-07	1.22E-06	3.79E-07	3.79E-07	-	-	-	-	3.57E-06
Dichlorobenzene	-	-	-	-	1.88E-04	1.88E-04	-	-	-	-	-	-	-	-	-	-	-	3.76E-04
Ethylbenzene	1.67E-01	1.67E-01	1.67E-01	1.67E-01	-	-	-	-	-	-	-	-	-	-	-	-	-	6.69E-01
Fluoranthene	-	-	-	-	4.71E-07	4.71E-07	-	-	7.09E-06	7.09E-06	1.42E-05	4.94E-06	4.94E-06	-	-	-	-	3.92E-05
Fluorene	-	-	-	-	4.39E-07	4.39E-07	-	-	2.25E-05	2.25E-05	4.51E-05	1.90E-05	1.90E-05	-	-	-	-	1.29E-04
Formaldehyde	1.27E+00	1.27E+00	1.27E+00	1.27E+00	1.18E-02	1.18E-02	-	-	1.39E-04	1.39E-04	2.78E-04	7.66E-04	7.66E-04	-	-	-	-	5.12E+00
Hexane	-	-	-	-	2.82E-01	2.82E-01	-	-	-	-	-	-	-	-	-	-	-	5.65E-01
Indeno(1,2,3-cd)pyrene	-	-	-	-	2.82E-07	2.82E-07	-	-	7.29E-07	7.29E-07	1.46E-06	2.43E-07	2.43E-07	-	-	-	-	3.97E-06
Lead	-	-	-	-	7.84E-05	7.84E-05	-	-	-	-	-	-	-	-	-	-	-	1.57E-04
Manganese	-	-	-	-	5.96E-05	5.96E-05	-	-	-	-	-	-	-	-	-	-	-	1.19E-04
Mercury	-	-	-	-	4.08E-05	4.08E-05	-	-	-	-	-	-	-	-	-	-	-	8.16E-05
Naphthalene	4.64E-03	4.64E-03	4.64E-03	4.64E-03	9.57E-05	9.57E-05	-	-	2.29E-04	2.29E-04	4.58E-04	5.51E-05	5.51E-05	-	-	-	-	1.98E-02
Nickel	-	-	-	-	3.29E-04	3.29E-04	-	-	-	-	-	-	-	-	-	-	-	6.59E-04
PAH	3.45E-03	3.45E-03	3.45E-03	3.45E-03	-	-	-	-	-	-	-	-	-	-	-	-	-	1.38E-02
Phenanthrene	-	-	-	-	2.67E-06	2.67E-06	-	-	7.18E-05	7.18E-05	1.44E-04	1.91E-05	1.91E-05	-	-	-	-	3.31E-04
Propylene Oxide	2.10E-01	2.10E-01	2.10E-01	2.10E-01	-	-	-	-	-	-	-	-	-	-	-	-	-	8.38E-01
Pyrene	-	-	-	-	7.84E-07	7.84E-07	-	-	6.53E-06	6.53E-06	1.31E-05	3.10E-06	3.10E-06	-	-	-	-	3.39E-05
Selenium	-	-	-	-	3.76E-06	3.76E-06	-	-	-	-	-	-	-	-	-	-	-	7.53E-06
Toluene	4.98E-01	4.98E-01	4.98E-01	4.98E-01	5.33E-04	5.33E-04	-	-	4.95E-04	4.95E-04	9.89E-04	2.66E-04	2.66E-04	-	-	-	-	1.99E+00
Xylenes	4.77E-01	4.77E-01	4.77E-01	4.77E-01	-	-	-	-	3.40E-04	3.40E-04	6.79E-04	1.85E-04	1.85E-04	-	-	-	-	1.91E+00
Total HAP	**3.09**	**3.09**	**3.09**	**3.09**	**0.30**	**0.30**	**0.00**	**0.00**	**0.00**	**0.00**	**0.01**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**12.95**
Maximum Single HAP[1]	**1.27**	**1.27**	**1.27**	**1.27**	**0.28**	**0.28**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**5.12**

1. Formaldehyde is the single HAP with the greatest facility emissions.

Emission Calculations

Facility Wide Uncontrolled Potential Emissions Summary

Pollutant	CCCT1 (tpy)	CCCT2 (tpy)	CCCT3 (tpy)	CCCT4 (tpy)	B001 (tpy)	B002 (tpy)	CT01 (tpy)	CT02 (tpy)	EG01 (tpy)	EG02 (tpy)	EG03 (tpy)	FP01 (tpy)	FP02 (tpy)	DM01-DM06 (tpy)	Storage Tanks (tpy)	Lime Silo (tpy)	Circuit Breakers (tpy)	Facility Wide Total (tpy)
CO	242.65	242.65	242.65	242.65	28.91	28.91	-	-	1.45	1.45	0.49	0.43	0.43	-	-	-	-	1,032.67
NO_X	359.16	359.16	359.16	359.16	10.99	10.99	-	-	2.65	2.65	0.64	0.50	0.50	-	-	-	-	1,465.56
TSP	78.84	78.84	78.84	78.84	2.63	2.63	3.73	3.73	0.08	0.08	0.03	0.03	0.03	0.35	-	0.66	-	329.33
Total PM_{10}	78.84	78.84	78.84	78.84	2.63	2.63	2.37	2.37	0.08	0.08	0.03	0.03	0.03	0.35	-	0.31	-	326.26
Total $PM_{2.5}$	78.84	78.84	78.84	78.84	2.63	2.63	0.01	0.01	0.08	0.08	0.03	0.03	0.03	0.35	-	0.05	-	321.28
SO_2	24.97	24.97	24.97	24.97	0.77	0.77	-	-	0.00	0.00	0.01	0.19	0.19	-	-	-	-	101.80
VOC	33.29	33.29	33.29	33.29	1.75	1.75	-	-	0.05	0.05	0.12	0.03	0.03	0.35	0.11	-	-	137.40
H_2SO_4	19.69	19.69	19.69	19.69	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	78.78
Fluorides (Other than HF)	0.00	0.00	0.00	0.00	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	0.00
NH_3	69.42	69.42	69.42	69.42	0.00	0.00	-	-	-	-	-	-	-	-	-	-	-	277.69
CO_2	1,183,104	1,183,104	1,183,104	1,183,104	40,958	40,958	-	-	299	299	584	86	86	-	-	-	-	4,815,684.96
CH_4	21.74	21.74	21.74	21.74	0.77	0.77	-	-	0.01	0.01	0.02	0.003	0.003	-	-	-	-	88.54
N_2O	2.17	2.17	2.17	2.17	0.08	0.08	-	-	0.002	0.002	0.005	0.001	0.001	-	-	-	-	8.86
SF_6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0009	0.0009
CO_2e	1,184,234	1,184,234	1,184,234	1,184,234	40,998	40,998	-	-	300	300	586	86	86	-	-	-	22	4,820,312.50

1. TSP emissions are only filterable PM emissions.
2. PM_{10} and $PM_{2.5}$ emissions are estimated as total particulate emissions (filterable + condensable).

Emission Calculations

Facility Wide Potential HAP Emissions Summary

Pollutant	CCCT1 (tpy)	CCCT2 (tpy)	CCCT3 (tpy)	CCCT4 (tpy)	B001 (tpy)	B002 (tpy)	CT01 (tpy)	CT02 (tpy)	EG01 (tpy)	EG02 (tpy)	EG03 (tpy)	FP01 (tpy)	FP02 (tpy)	DM01-DM06 (tpy)	Storage Tanks (tpy)	Lime Silo (tpy)	Circuit Breakers (tpy)	CCCT Plant Total (tpy)
1,3-Butadiene	5.91E-04	5.91E-04	5.91E-04	5.91E-04	-	-	-	-	-	-	-	2.54E-05	2.54E-05	-	-	-	-	2.41E-03
2-Methylnaphthalene	-	-	-	-	3.76E-06	3.76E-06	-	-	-	-	-	-	-	-	-	-	-	7.53E-06
3-Methylchloranthrene	-	-	-	-	2.82E-07	2.82E-07	-	-	-	-	-	-	-	-	-	-	-	5.65E-07
7,12-Dimethylbenz(a)anthracene	-	-	-	-	2.51E-06	2.51E-06	-	-	-	-	-	-	-	-	-	-	-	5.02E-06
Acenaphthene	-	-	-	-	2.82E-07	2.82E-07	-	-	8.24E-06	8.24E-06	1.65E-05	9.22E-07	9.22E-07	-	-	-	-	3.54E-05
Acenaphthylene	-	-	-	-	2.82E-07	2.82E-07	-	-	1.62E-05	1.62E-05	3.25E-05	3.29E-06	3.29E-06	-	-	-	-	7.21E-05
Acetaldehyde	4.20E-01	4.20E-01	4.20E-01	4.20E-01	-	-	-	-	4.44E-05	4.44E-05	8.87E-05	4.98E-04	4.98E-04	-	-	-	-	1.68E+00
Acrolein	5.46E-02	5.46E-02	5.46E-02	5.46E-02	-	-	-	-	1.39E-05	1.39E-05	2.77E-05	6.01E-05	6.01E-05	-	-	-	-	2.19E-01
Anthracene	-	-	-	-	3.76E-07	3.76E-07	-	-	2.16E-06	2.16E-06	4.33E-06	1.21E-06	1.21E-06	-	-	-	-	1.18E-05
Arsenic	-	-	-	-	3.14E-05	3.14E-05	-	-	-	-	-	-	-	-	-	-	-	6.27E-05
Beryllium	-	-	-	-	1.88E-06	1.88E-06	-	-	-	-	-	-	-	-	-	-	-	3.76E-06
Benzene	1.27E-01	1.27E-01	1.27E-01	1.27E-01	3.29E-04	3.29E-04	-	-	1.37E-03	1.37E-03	2.73E-03	6.06E-04	6.06E-04	-	-	-	-	5.17E-01
Benz(a)anthracene	-	-	-	-	2.82E-07	2.82E-07	-	-	1.09E-06	1.09E-06	2.19E-06	1.09E-06	1.09E-06	-	-	-	-	7.13E-06
Benzo(a)pyrene	-	-	-	-	1.88E-07	1.88E-07	-	-	4.52E-07	4.52E-07	9.05E-07	1.22E-07	1.22E-07	-	-	-	-	2.43E-06
Benzo(b)fluoranthene	-	-	-	-	2.82E-07	2.82E-07	-	-	1.95E-06	1.95E-06	3.91E-06	6.43E-08	6.43E-08	-	-	-	-	8.51E-06
Benzo(g,h,i)perylene	-	-	-	-	1.88E-07	1.88E-07	-	-	9.79E-07	9.79E-07	1.96E-06	3.17E-07	3.17E-07	-	-	-	-	4.93E-06
Benzo(k)fluoranthene	-	-	-	-	2.82E-07	2.82E-07	-	-	3.84E-07	3.84E-07	7.67E-07	1.01E-07	1.01E-07	-	-	-	-	2.30E-06
Cadmium	-	-	-	-	1.73E-04	1.73E-04	-	-	-	-	-	-	-	-	-	-	-	3.45E-04
Chromium	-	-	-	-	2.20E-04	2.20E-04	-	-	-	-	-	-	-	-	-	-	-	4.39E-04
Chrysene	-	-	-	-	2.82E-07	2.82E-07	-	-	2.69E-06	2.69E-06	5.39E-06	2.29E-07	2.29E-07	-	-	-	-	1.18E-05
Cobalt	-	-	-	-	1.32E-05	1.32E-05	-	-	-	-	-	-	-	-	-	-	-	2.64E-05
Dibenzo(a,h)anthracene	-	-	-	-	1.88E-07	1.88E-07	-	-	6.09E-07	6.09E-07	1.22E-06	3.79E-07	3.79E-07	-	-	-	-	3.57E-06
Dichlorobenzene	-	-	-	-	1.88E-04	1.88E-04	-	-	-	-	-	-	-	-	-	-	-	3.76E-04
Ethylbenzene	2.23E-01	2.23E-01	2.23E-01	2.23E-01	-	-	-	-	-	-	-	-	-	-	-	-	-	8.92E-01
Fluoranthene	-	-	-	-	4.71E-07	4.71E-07	-	-	7.09E-06	7.09E-06	1.42E-05	4.94E-06	4.94E-06	-	-	-	-	3.92E-05
Fluorene	-	-	-	-	4.39E-07	4.39E-07	-	-	2.25E-05	2.25E-05	4.51E-05	1.90E-05	1.90E-05	-	-	-	-	1.29E-04
Formaldehyde	1.70E+00	1.70E+00	1.70E+00	1.70E+00	1.18E-02	1.18E-02	-	-	1.39E-04	1.39E-04	2.78E-04	7.66E-04	7.66E-04	-	-	-	-	6.82E+00
Hexane	-	-	-	-	2.82E-01	2.82E-01	-	-	-	-	-	-	-	-	-	-	-	5.65E-01
Indeno(1,2,3-cd)pyrene	-	-	-	-	2.82E-07	2.82E-07	-	-	7.29E-07	7.29E-07	1.46E-06	2.43E-07	2.43E-07	-	-	-	-	3.97E-06
Lead	-	-	-	-	7.84E-05	7.84E-05	-	-	-	-	-	-	-	-	-	-	-	1.57E-04
Manganese	-	-	-	-	5.96E-05	5.96E-05	-	-	-	-	-	-	-	-	-	-	-	1.19E-04
Mercury	-	-	-	-	4.08E-05	4.08E-05	-	-	-	-	-	-	-	-	-	-	-	8.16E-05
Naphthalene	6.18E-03	6.18E-03	6.18E-03	6.18E-03	9.57E-05	9.57E-05	-	-	2.29E-04	2.29E-04	4.58E-04	5.51E-05	5.51E-05	-	-	-	-	2.59E-02
Nickel	-	-	-	-	3.29E-04	3.29E-04	-	-	-	-	-	-	-	-	-	-	-	6.59E-04
PAH	4.60E-03	4.60E-03	4.60E-03	4.60E-03	-	-	-	-	-	-	-	-	-	-	-	-	-	1.84E-02
Phenanthrene	-	-	-	-	2.67E-06	2.67E-06	-	-	7.18E-05	7.18E-05	1.44E-04	1.91E-05	1.91E-05	-	-	-	-	3.31E-04
Propylene Oxide	2.79E-01	2.79E-01	2.79E-01	2.79E-01	-	-	-	-	-	-	-	-	-	-	-	-	-	1.12E+00
Pyrene	-	-	-	-	7.84E-07	7.84E-07	-	-	6.53E-06	6.53E-06	1.31E-05	3.10E-06	3.10E-06	-	-	-	-	3.39E-05
Selenium	-	-	-	-	3.76E-06	3.76E-06	-	-	-	-	-	-	-	-	-	-	-	7.53E-06
Toluene	6.64E-01	6.64E-01	6.64E-01	6.64E-01	5.33E-04	5.33E-04	-	-	4.95E-04	4.95E-04	9.89E-04	2.66E-04	2.66E-04	-	-	-	-	2.66E+00
Xylenes	6.35E-01	6.35E-01	6.35E-01	6.35E-01	-	-	-	-	3.40E-04	3.40E-04	6.79E-04	1.85E-04	1.85E-04	-	-	-	-	2.54E+00
Total HAP	**4.11**	**4.11**	**4.11**	**4.11**	**0.30**	**0.30**	**0.00**	**0.00**	**0.00**	**0.00**	**0.01**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**17.07**
Maximum Single HAP[1]	**1.70**	**1.70**	**1.70**	**1.70**	**0.28**	**0.28**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**6.82**

1. Formaldehyde is the single HAP with the greatest facility emissions.

Emission Calculations

CCCT Normal Operating Scenario Parameters

Operating Data for each CCCT	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9
Load (%)	100	100	100	75	75	75	47	46	56
Inlet Air Cooling (on/off)	On	Off	Off	On	Off	Off	On	Off	Off
Ambient Temperature (F)	92	50	-10	92	50	-10	92	52	-10
Duct Burner Firing (yes/no)	Yes	No	No	No	No	No	No	No	No
CT Heat Consumption (MMBtu/hr) (HHV)	2,000	2,080	2,230	1,540	1,660	1,820	1,220	1,280	1,520
DB Heat Consumption (MMBtu/hr) (HHV)	251	0	0	0	0	0	0	0	0
Total Heat Consumption (MMBtu/hr) (HHV)	2,251	2,080	2,230	1,540	1,660	1,820	1,220	1,280	1,520

Startup/Shutdown Emissions (Worst-case) -Per CT

Pollutant	Cold Start Emissions (lb/event)	Warm Start Emissions (lb/event)	Hot Start Emissions (lb/event)	Shutdown Emissions (lb/event)
CO	2,125	705	454	445
NO_X	443	162	75	22
TSP	37	15	7	4
Total PM_{10}	37	15	7	4
Total $PM_{2.5}$	37	15	7	4
SO_2	4	2	1	1
VOC	153	39	22	12
Lead	-	-	-	-
H_2SO_4	-	-	-	-
Fluorides (other than HF)	-	-	-	-
NH_3	-	-	-	-
CO_2	226,148.83	105,873.46	60,202.56	36,718.37
CH_4	4.27	2.00	1.14	0.69
N_2O	0.43	0.20	0.11	0.07

Emissions (lb/event) are for conventional startup/shutdown of lead combustion turbine.
For GHG, emissions (lb/event) calculated based on fuel consumed per event, and default pollutant emission factor for natural gas per 40 CFR 98, Subpart C.
Emissions (lb/event) assume no control devices.
Conservatively assumed that $PM_{2.5}$ emissions equal PM_{10} emissions.
Conservatively assumed that TSP emissions equal PM_{10} emissions.

Total Startup and Shutdown Hours

Cold Start Hours, per event	3.08
Warm Start Hours, per event	1.25
Hot Start Hours, per event	0.58
Shutdown Hours, per event	0.30

Minimum Duration Between Operation:

Cold Starts (> 72 hrs downtime):	72.0
Warm Starts (8-48 hrs downtime):	8.0
Hot Starts (0-8 hrs downtime):	0.0

Events per Year:

Cold Startups events per year per CT	16	
Warm Startups events per year per CT	198	
Hot Startups events per year per CT	4	
Shutdown events per year	218	Same as total startups
Startup and Shutdown Operation (hr/yr)	3100.6	Sum of duration + downtime multiplied by number of events, for each event type

Emission Calculations

CCCT Criteria and GHG Emission Factors[1,2,3] - Continuous Operation

Emissions Data for each CCCT Load Duct Burner Firing	Case 1 100 Yes	Case 2 100 No	Case 3 100 No	Case 4 75 No	Case 5 75 No	Case 6 75 No	Case 7 47 No	Case 8 46 No	Case 9 56 No
Stack Temperature (F)	188	192	196	177	178	185	175	175	176
Total Exhaust Gas Flow (acfm)	1,143,330	1,165,380	1,258,320	764,990	910,067	1,005,403	599,834	694,208	830,243
CO (lb/hr)	10.0	9.2	9.9	6.8	7.3	8.0	5.4	5.7	6.7
NO_X as NO_2 (lb/hr)	16.4	15.1	16.2	11.2	12.0	13.1	8.9	9.3	11.0
TSP (lb/hr)[4]	18.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Total PM_{10}(lb/hr)	18.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Total $PM_{2.5}$ (lb/hr)[4]	18.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
SO_2 (lb/hr)	5.7	5.3	5.7	3.9	4.2	4.6	3.1	3.3	3.8
VOC (lb/hr)	5.7	2.7	2.8	2.0	2.1	2.3	1.6	1.6	1.9
Lead (lb/hr)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H_2SO_4 (lb/hr)[7]	4.5	4.1	4.5	3.1	3.3	3.6	2.4	2.6	3.0
Fluorides (other than HF) (lb/hr)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ammonia Slip (lb/hr)	15.9	14.7	15.7	10.8	11.7	12.8	8.6	9.0	10.7
CO_2 (lb/hr)	270,115	249,785	267,828	185,248	199,683	218,930	146,755	153,972	182,842
CH_4 (lb/MMBtu)[5]	2.2E-03	2.2E-03	2.2E-03	2.2E-03	2.2E-03	2.2E-03	2.2E-03	2.2E-03	2.2E-03
CH_4 (lb/hr)[6]	5.0	4.6	4.9	3.4	3.7	4.0	2.7	2.8	3.4
N_2O (lb/MMBtu)[5]	2.2E-04	2.2E-04	2.2E-04	2.2E-04	2.2E-04	2.2E-04	2.2E-04	2.2E-04	2.2E-04
N_2O (lb/hr)[6]	0.5	0.5	0.5	0.3	0.4	0.4	0.3	0.3	0.3

1. Emission factors obtained from client, unless otherwise noted.
2. Emission factors were given per 2x1 block. Numbers in table are presented per combustion turbine.
3. Emission factors in lb/hr based on GT Pro software, with the following modifications & assumptions

NO_X emission factors rounded up to next whole number to account for software understimating ppmvd. Duct burner emissions based on 0.06 lb NO_X/MMBtu.

CO emission factors rounded up (or, for whole numbers, increased by 1) to account for decrease in function of oxidation catalyst over time. Duct burner emissions based on 0.04 lb CO/MMBtu. 80% control assumed.

VOC emission factors based on GE guaranteed levels, plus a duct burner emission factor of 0.006 lb VOC as CH_4/MMBTU (HHV) and conservative assumption of 25% reduction of VOC across the oxidation catalyst.

PM_{10} values based on GE-published values for engine exhaust of 9 lb/hr filterable and 9 lb/hr condensable. For duct burner case, PM_{10} emission factor of 0.0045 lb/Mmbtu (HHV) was used as advised by Vogt (HRSG supplier).

SO_2 emission factor based on 0.75 gr/100 scf sulfur in fuel.

4. TSP and $PM_{2.5}$ emission factors conservatively assumed equal to PM_{10}.
5. Emission factors obtained from 40 CFR 98, Subpart C. Note that these are uncontrolled emission factors.
6. Emission factors in lb/hr calculated based on 40 CFR 98, Subpart C emission factors total heat consumption (MMBtu/hr) for each case.
7. H_2SO_4 emission factors calculated based on 34% molar conversion of SO_2 to SO_3 across the oxidation catalyst, and 100% conversion of SO_3 to H_2SO_4.

SO_3 formed across SCR (mol/hr) = [SO_2 Emissions Post-SCR (mol/hr) / 0.66] - [SO_2 Emissions Post-SCR (mol/hr)]

H_2SO_4 Emissions (lb/hr) = SO_3 formed across SCR (mol/hr) * (1 mol H_2SO_4/ 1 mol SO_3) * (98 g H_2SO_4 /mol) * (kg/1000g) * (lb/0.45 kg)

CCCT Criteria and GHG Emission Factors - Startup/Shutdown

Pollutant	Cold Start Emissions (lb/hr)	Warm Start Emissions (lb/hr)	Hot Start Emissions (lb/hr)	Shutdown Emissions (lb/hr)
CO	689.2	564.0	454.0	445.0
NO_X	143.7	129.6	75.0	22.0
TSP	12.0	12.0	7.0	4.0
Total PM_{10}	12.0	12.0	7.0	4.0
Total $PM_{2.5}$	12.0	12.0	7.0	4.0
SO_2	1.2	1.4	1.0	0.8
VOC	49.6	31.2	22.0	12.0
Lead	-	-	-	-
H_2SO_4	-	-	-	-
Fluorides (other than HF)	-	-	-	-
NH_3	-	-	-	-
CO_2	73,345.6	84,698.8	60,202.6	36,718.4
CH_4	1.4	1.6	1.1	0.7
N_2O	0.1	0.2	0.1	0.1

Methodology:

For events lasting longer than 1 hr: Emissions (lb/hr) = (lb/event) / (hr/event)

For events lasting less than 1 hr: Emissions (lb/hr) = lb/event

Emissions (lb/event) are for conventional startup/shutdown of lead combustion turbine.

"Stack exit conditions for startup JW R2 9-13.doc." GHG lb/event calculated based on fuel consumption per event and default pollutant emission factors in 40 CFR 98 Subpart C.

Emissions (lb/event) assume no control devices.

Conservatively assumed that $PM_{2.5}$ emissions equal PM_{10} emissions.

Conservatively assumed that TSP emissions equal PM_{10} emissions.

Emission Calculations

Summary of CCCT Criteria and GHG Potential Emissions

Number of CCCTs	4	
Potential Operation	8,760	hr/yr

	Maximum # Events		Event Duration		Total Event Hours		Minimum Downtime Between Events		Total Event & Downtime Hours		Event Duration	
Number of Cold Starts (each CCCT)	16	events/yr	3.08	hr/event	49.3	hr/yr	72	hr	1,201	hr/yr	185	min/event
Number of Warm Starts (each CCCT)	198	events/yr	1.25	hr/event	247.5	hr/yr	8	hr	1,832	hr/yr	75	min/event
Number of Hot Starts (each CCCT)	4	events/yr	0.58	hr/event	2.3	hr/yr	-	hr	2	hr/yr	35	min/event
Number of Shutdowns (each CCCT)	218	events/yr	0.30	hr/event	65.4	hr/yr	-	hr	65	hr/yr	18	min/event

CONTROLLED (per turbine)		UNCONTROLLED (per turbine) - Weighted Averages				Continuous Normal Operation[1]		Operation with Maximum Startups and Shutdowns[2]		Worst-Case Potential Emissions, Each CCCT		Worst-Case Potential Emissions, All CCCT	
Pollutant	Normal Operation (lb/hr)	Cold Startup (lb/hr)	Warm Startup (lb/hr)	Hot Startup (lb/hr)	Shutdown (lb/hr)	Each CCCT (tpy)	All CCCT (tpy)	Each CCCT (tpy)	All CCCT (tpy)	(lb/hr)[3]	(tpy)[4]	(lb/hr)	(tpy)
CO	10.0	689.2	564.0	454.0	445.0	43.6	174.3	130.0	520.1	689.2	130.0	2,756.8	520.1
NO_X	16.4	143.7	129.6	75.0	22.0	71.8	287.3	66.8	267.2	143.7	71.8	574.7	287.3
TSP	18.0	12.0	12.0	7.0	4.0	78.8	315.4	52.9	211.4	18.0	78.8	72.0	315.4
Total PM_{10}	18.0	12.0	12.0	7.0	4.0	78.8	315.4	52.9	211.4	18.0	78.8	72.0	315.4
Total $PM_{2.5}$	18.0	12.0	12.0	7.0	4.0	78.8	315.4	52.9	211.4	18.0	78.8	72.0	315.4
SO_2	5.7	1.2	1.4	1.0	0.8	25.0	99.9	16.4	65.5	5.7	25.0	22.8	99.9
VOC	5.7	49.6	31.2	22.0	12.0	25.0	99.9	21.6	86.5	49.6	25.0	198.5	99.9
Lead	-	-	-	-	-	-	-	-	-	-	-	-	-
H_2SO_4	4.5	-	-	-	-	19.7	78.8	12.7	50.9	4.5	19.7	18.0	78.8
Fluorides (Other than HF)	-	-	-	-	-	-	-	-	-	-	-	-	-
NH_3	15.9	-	-	-	-	69.4	277.7	44.9	179.4	15.9	69.4	63.4	277.7
CO_2	270,115.0	73,345.6	84,698.8	60,202.6	36,718.4	1,183,104	4,732,415	777,911	3,111,642	270,115	1,183,104	1,080,460	4,732,415
CH_4	5.0	1.4	1.6	1.1	0.7	22	87	14.3	57	5	22	20	87
N_2O	0.5	0.1	0.2	0.1	0.1	2.2	8.7	1.4	5.7	0.5	2.2	2.0	8.7

1. Based on 8,760 hr/yr at normal operations.

2. Based on maximum number of hours of each startup or shutdown per year multiplied by the average lb/hr rate for each event type plus normal operation for the remainder of the year (8,760 hr/yr - total event & downtime hours).

3. Based on the worst-case of normal, startup (cold, warm or hot), or shutdown operations.

4. Based on the worst-case continuous normal operation or operation with maximum startups and shutdowns.

Emission Calculations

Summary of CCCT Criteria and GHG Potential Emissions

Number of CCCTs	4	
Potential Operation	8,760	hr/yr

	Maximum # Events		Event Duration		Total Event Hours		Minimum Downtime Between Events		Total Event & Downtime Hours		Event Duration	
Number of Cold Starts (each CCCT)	16	events/yr	3.08	hr/event	49.3	hr/yr	72	hr	1,201	hr/yr	185	min/event
Number of Warm Starts (each CCCT)	198	events/yr	1.25	hr/event	247.5	hr/yr	8	hr	1,832	hr/yr	75	min/event
Number of Hot Starts (each CCCT)	4	events/yr	0.58	hr/event	2.3	hr/yr	-	hr	2	hr/yr	35	min/event
Number of Shutdowns (each CCCT)	218	events/yr	0.30	hr/event	65.4	hr/yr	-	hr	65	hr/yr	18	min/event

UNCONTROLLED (per turbine)		UNCONTROLLED (per turbine) - Weighted Averages				Continuous Normal Operation[4]		Operation with Maximum Startups and Shutdowns[5]		Worst-Case Potential Emissions, Each CCCT		Worst-Case Potential Emissions, All CCCT	
Pollutant	Normal Operation[1,2,3] (lb/hr)	Cold Startup (lb/hr)	Warm Startup (lb/hr)	Hot Startup (lb/hr)	Shutdown (lb/hr)	Each CCCT (tpy)	All CCCT (tpy)	Each CCCT (tpy)	All CCCT (tpy)	(lb/hr)[6]	(tpy)[7]	(lb/hr)	(tpy)
CO	49.8	689.2	564.0	454.0	445.0	217.9	871.6	242.7	970.6	689.2	242.7	2,756.8	970.6
NO_X	82.0	143.7	129.6	75.0	22.0	359.2	1,436.6	252.4	1,009.7	143.7	359.2	574.7	1,436.6
TSP	18.0	12.0	12.0	7.0	4.0	78.8	315.4	52.9	211.4	18.0	78.8	72.0	315.4
Total PM_{10}	18.0	12.0	12.0	7.0	4.0	78.8	315.4	52.9	211.4	18.0	78.8	72.0	315.4
Total $PM_{2.5}$	18.0	12.0	12.0	7.0	4.0	78.8	315.4	52.9	211.4	18.0	78.8	72.0	315.4
SO_2	5.7	1.2	1.4	1.0	0.8	25.0	99.9	16.4	65.5	5.7	25.0	22.8	99.9
VOC	7.6	49.6	31.2	22.0	12.0	33.3	133.2	27.0	108.0	49.6	33.3	198.5	133.2
Lead	-	-	-	-	-	-	-	-	-	-	-	-	-
H_2SO_4	4.5	-	-	-	-	19.7	78.8	12.7	50.9	4.5	19.7	18.0	78.8
Fluorides (Other than HF)	-	-	-	-	-	-	-	-	-	-	-	-	-
NH_3	15.9	-	-	-	-	69.4	277.7	44.9	179.4	15.9	69.4	63.4	277.7
CO_2	270,115.0	73,345.6	84,698.8	60,202.6	36,718.4	1,183,104	4,732,415	777,911	3,111,642	270,115	1,183,104	1,080,460	4,732,415
CH_4	5.0	1.4	1.6	1.1	0.7	22	87	14.3	57	5	22	20	87
N_2O	0.5	0.1	0.2	0.1	0.1	2.2	8.7	1.4	5.7	0.5	2.2	2.0	8.7

1. 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.
2. Assumes 80% control of NO_X from selective catalytic reduction system to estimate uncontrolled emission factor. Actual control efficiency will vary based on ambient air and load conditions.
3. 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.
4. Based on 8,760 hr/yr at normal operations.
5. Based on maximum number of hours of each startup or shutdown per year multiplied by the average lb/hr rate for each event type plus normal operation for the remainder of the year (8,760 hr/yr - total event & downtime hours).
6. Based on the worst-case of normal, startup (cold, warm or hot), or shutdown operations.
7. Based on the worst-case continuous normal operation or operation with maximum startups and shutdowns.

Emission Calculations

CCCT Maximum Potential HAP Emissions - CT

CCCTs

Short-term Heat Input (each)	2,230	MMBtu/hr (HHV), worst-case scenario
Potential Operation	8,760	hr/yr
Organic Pollutant Control	25%	(from Oxidation Catalyst)
Number of CCCT	4	

Pollutant	HAP Reason/CAS	Organic?	Uncontrolled Emission Factor[1] (lb/MMBtu)	Potential Emissions Each CCCT[2] (lb/hr)	(tpy)	Potential Emissions All CCCT[2] (lb/hr)	(tpy)
1,3-Butadiene	106990	Yes	6.05E-08	1.01E-04	4.43E-04	4.05E-04	1.77E-03
Acetaldehyde	75070	Yes	4.31E-05	7.20E-02	3.15E-01	2.88E-01	1.26E+00
Acrolein	107028	Yes	5.60E-06	9.36E-03	4.10E-02	3.74E-02	1.64E-01
Benzene	71432	Yes	1.30E-05	2.18E-02	9.56E-02	8.73E-02	3.82E-01
Ethylbenzene	100414	Yes	2.28E-05	3.82E-02	1.67E-01	1.53E-01	6.69E-01
Formaldehyde[3]	50000	Yes	1.74E-04	2.91E-01	1.27E+00	1.16E+00	5.10E+00
Naphthalene	91203	Yes	6.33E-07	1.06E-03	4.64E-03	4.23E-03	1.85E-02
PAH	POM	Yes	4.71E-07	7.87E-04	3.45E-03	3.15E-03	1.38E-02
Propylene Oxide	75569	Yes	2.86E-05	4.78E-02	2.10E-01	1.91E-01	8.38E-01
Toluene	108883	Yes	6.80E-05	1.14E-01	4.98E-01	4.55E-01	1.99E+00
Xylenes	108383, 106423	Yes	6.51E-05	1.09E-01	4.77E-01	4.35E-01	1.91E+00
Total HAP				**7.05E-01**	**3.09E+00**	**2.82E+00**	**1.23E+01**
Maximum Single HAP				**2.91E-01**	**1.27E+00**	**1.16E+00**	**5.10E+00**

1. Unless otherwise noted, emission factors are based on average of large (>40 MW) natural gas-fired turbine test data from AP-42 Section 3.1.

2. Includes application of the control efficiency from the oxidation catalyst for organic pollutants.

3. Formaldehyde custom emission factor excludes a single high outlier and a single low outlier.

Emission Calculations

CCCT Maximum Potential HAP Emissions

CCCTs

Short-term Heat Input (each)	2,230	MMBtu/hr (HHV), worst-case scenario
Potential Operation	8,760	hr/yr
Number of CCCT	4	

Pollutant	HAP Reason/CAS	Organic?	Uncontrolled Emission Factor[1] (lb/MMBtu)	Potential Emissions Each CCCT (lb/hr)	Potential Emissions Each CCCT (tpy)	Potential Emissions All CCCT (lb/hr)	Potential Emissions All CCCT (tpy)
1,3-Butadiene	106990	Yes	6.05E-08	1.35E-04	5.91E-04	5.40E-04	2.36E-03
Acetaldehyde	75070	Yes	4.31E-05	9.60E-02	4.20E-01	3.84E-01	1.68E+00
Acrolein	107028	Yes	5.60E-06	1.25E-02	5.46E-02	4.99E-02	2.19E-01
Benzene	71432	Yes	1.30E-05	2.91E-02	1.27E-01	1.16E-01	5.10E-01
Ethylbenzene	100414	Yes	2.28E-05	5.09E-02	2.23E-01	2.04E-01	8.92E-01
Formaldehyde[2]	50000	Yes	1.74E-04	3.88E-01	1.70E+00	1.55E+00	6.80E+00
Naphthalene	91203	Yes	6.33E-07	1.41E-03	6.18E-03	5.65E-03	2.47E-02
PAH	POM	Yes	4.71E-07	1.05E-03	4.60E-03	4.20E-03	1.84E-02
Propylene Oxide	75569	Yes	2.86E-05	6.38E-02	2.79E-01	2.55E-01	1.12E+00
Toluene	108883	Yes	6.80E-05	1.52E-01	6.64E-01	6.06E-01	2.65E+00
Xylenes	108383, 106423	Yes	6.51E-05	1.45E-01	6.35E-01	5.80E-01	2.54E+00
Total HAP				**9.39E-01**	**4.11E+00**	**3.76E+00**	**1.65E+01**
Maximum Single HAP				**3.88E-01**	**1.70E+00**	**1.55E+00**	**6.80E+00**

1. Unless otherwise noted, emission factors are based on average of large (>40 MW) natural gas-fired turbine test data from AP-42 Section 3.1.

2. Formaldehyde custom emission factor excludes a single high outlier and a single low outlier.

Auxiliary Boiler Potential NSR-Regulated and GHG Pollutant Emissions

Auxiliary Boiler Data

Maximum Heat Input	80.00	MMBtu/hr (HHV)
Fuel Heat Content	1,020	MMBtu/MMscf (HHV)
Potential Operation	8,760	hr/yr
Number of Auxiliary Boilers	2	

Criteria and GHG Pollutant Emissions

Pollutant	Emission Factor (lb/hr)	Emission Factor (lb/MMBtu)[1]	Potential Emissions (each boiler) (lb/hr)	Potential Emissions (each boiler) (tpy)	Potential Emissions (both boilers) (lb/hr)	Potential Emissions (both boilers) (tpy)
CO	6.6	-	6.60	28.91	13.20	57.82
NO_X	2.5	-	2.51	10.99	5.02	21.99
TSP	0.6	-	0.60	2.63	1.20	5.26
Total PM_{10}	0.6	-	0.60	2.63	1.20	5.26
Total $PM_{2.5}$	0.6	-	0.60	2.63	1.20	5.26
SO_2[3]	-	0.00221	0.18	0.77	0.35	1.55
VOC	0.4	-	0.40	1.75	0.80	3.50
Lead	-	0.0	0.00	0.00	0.00	0.00
H_2SO_4	0.0	0.0	0.00	0.00	0.00	0.00
Fluorides (other than HF)	0.0	0.0	0.00	0.00	0.00	0.00
NH_3	0.0	0.0	0.00	0.00	0.00	0.00
CO_2	-	116.9	9351.13	40957.94	18702.25	81915.88
CH_4	-	0.0	0.18	0.77	0.35	1.54
N_2O	-	0.0	0.02	0.08	0.04	0.15

1. Factor based on conversion of AP-42 Section 1.4 emission factor in lb/MMscf to lb/MMBtu, based on natural gas HHV of 1,020 Btu/scf, per Table 1.4-1 footnote a. For GHGs, factor based on default pollutant emission factors for natural gas in 40 CFR 98, Subpart C, converted to lb/MMBtu based on natural gas HHV of 1,020 Btu/scf.

2. Per AP-42 Section 1.4, all PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented in AP-42 Section 1.4 may be used to estimate PM_{10} or $PM_{2.5}$ emissions. TSP/PM_{10}/$PM_{2.5}$ include filterable and condensable PM.

3. Assumed a sulfur content of 7,500 grains per MMscf.

Toxic/Hazardous Air Pollutant Emissions

Pollutant	Emission Factor[1] (lb/MMscf)	Emission Factor[1] (lb/MMBtu)	Potential Emissions (each boiler) (lb/hr)	Potential Emissions (each boiler) (tpy)	Potential Emissions (both boilers) (lb/hr)	Potential Emissions (both boilers) (tpy)
2-Methylnaphthalene	2.4E-05	2.4E-08	1.88E-06	8.24E-06	3.76E-06	1.65E-05
3-Methylchloranthrene	1.8E-06	1.8E-09	1.41E-07	6.18E-07	2.82E-07	1.24E-06
7,12-Dimethylbenz(a)anthracene	1.6E-05	1.6E-08	1.25E-06	5.50E-06	2.51E-06	1.10E-05
Acenaphthene	1.8E-06	1.8E-09	1.41E-07	6.18E-07	2.82E-07	1.24E-06
Acenaphthylene	1.8E-06	1.8E-09	1.41E-07	6.18E-07	2.82E-07	1.24E-06
Anthracene	2.4E-06	2.4E-09	1.88E-07	8.24E-07	3.76E-07	1.65E-06
Arsenic	2.0E-04	2.0E-07	1.57E-05	6.87E-05	3.14E-05	1.37E-04
Beryllium	1.2E-05	1.2E-08	9.41E-07	4.12E-06	1.88E-06	8.24E-06
Benzene	2.1E-03	2.1E-06	1.65E-04	7.21E-04	3.29E-04	1.44E-03
Benz(a)anthracene	1.8E-06	1.8E-09	1.41E-07	6.18E-07	2.82E-07	1.24E-06
Benzo(a)pyrene	1.2E-06	1.2E-09	9.41E-08	4.12E-07	1.88E-07	8.24E-07
Benzo(b)fluoranthene	1.8E-06	1.8E-09	1.41E-07	6.18E-07	2.82E-07	1.24E-06
Benzo(g,h,i)perylene	1.2E-06	1.2E-09	9.41E-08	4.12E-07	1.88E-07	8.24E-07
Benzo(k)fluoranthene	1.8E-06	1.8E-09	1.41E-07	6.18E-07	2.82E-07	1.24E-06
Cadmium	1.1E-03	1.1E-06	8.63E-05	3.78E-04	1.73E-04	7.56E-04
Chromium	1.4E-03	1.4E-06	1.10E-04	4.81E-04	2.20E-04	9.62E-04
Chrysene	1.8E-06	1.8E-09	1.41E-07	6.18E-07	2.82E-07	1.24E-06
Cobalt	8.4E-05	8.2E-08	6.59E-06	2.89E-05	1.32E-05	5.77E-05
Dibenzo(a,h)anthracene	1.2E-06	1.2E-09	9.41E-08	4.12E-07	1.88E-07	8.24E-07
Dichlorobenzene	1.2E-03	1.2E-06	9.41E-05	4.12E-04	1.88E-04	8.24E-04
Fluoranthene	3.0E-06	2.9E-09	2.35E-07	1.03E-06	4.71E-07	2.06E-06
Fluorene	2.8E-06	2.7E-09	2.20E-07	9.62E-07	4.39E-07	1.92E-06
Formaldehyde	7.5E-02	7.4E-05	5.88E-03	2.58E-02	1.18E-02	5.15E-02
Hexane	1.8E+00	1.8E-03	1.41E-01	6.18E-01	2.82E-01	1.24E+00
Indeno(1,2,3-cd)pyrene	1.8E-06	1.8E-09	1.41E-07	6.18E-07	2.82E-07	1.24E-06
Lead	5.0E-04	4.9E-07	3.92E-05	1.72E-04	7.84E-05	3.44E-04
Manganese	3.8E-04	3.7E-07	2.98E-05	1.31E-04	5.96E-05	2.61E-04
Mercury	2.6E-04	2.5E-07	2.04E-05	8.93E-05	4.08E-05	1.79E-04
Naphthalene	6.1E-04	6.0E-07	4.78E-05	2.10E-04	9.57E-05	4.19E-04
Nickel	2.1E-03	2.1E-06	1.65E-04	7.21E-04	3.29E-04	1.44E-03
Phenanthrene	1.7E-05	1.7E-08	1.33E-06	5.84E-06	2.67E-06	1.17E-05
Pyrene	5.0E-06	4.9E-09	3.92E-07	1.72E-06	7.84E-07	3.44E-06
Selenium	2.4E-05	2.4E-08	1.88E-06	8.24E-06	3.76E-06	1.65E-05
Toluene	3.4E-03	3.3E-06	2.67E-04	1.17E-03	5.33E-04	2.34E-03
Total HAP			**1.48E-01**	**6.49E-01**	**2.96E-01**	**1.30E+00**
Highest Single HAP			**1.41E-01**	**6.18E-01**	**2.82E-01**	**1.24E+00**

1. Per AP-42, Section 1.4, July 1998.

Emission Calculations

Cooling Tower Potential NSR-Regulated Pollutant Emissions

Number of cooling towers: 2

Cooling Towers

Cooling Tower Capacity (each) (gpm)	Total Dissolved Solids (ppm)	Drift Loss (%)	Drift Mass Flow Rate[1] (lb/hr)	Total TSP Emission Rate (each tower)[2,5] (lb/hr)	(tpy)	Total PM_{10} Emission Rate (each tower)[3,5,6] (lb/hr)	(tpy)	Total $PM_{2.5}$ Emission Rate (each tower)[4,5,6] (lb/hr)	(tpy)	Total TSP Emission Rate (both towers) (lb/hr)	(tpy)	Total PM_{10} Emission Rate (both towers) (lb/hr)	(tpy)	Total $PM_{2.5}$ Emission Rate (both towers) (lb/hr)	(tpy)
170,000	2,000	0.0005%	425.6	0.851	3.728	0.541	2.367	0.002	0.008	1.702	7.456	1.081	4.735	0.004	0.016

1. Drift mass flow rate (lb/hr) = Cooling tower capacity (gpm) x Density of water (8.34 lb/gal) x 60 (min/hour) x Drift loss (%) .
2. TSP emissions (lb/hr) = Drift mass flow rate (lb/hr) x TDS (ppm)/(106)
3. PM10 emissions (lb/hr) = Drift mass flow rate (lb/hr) x TDS (ppm)/(106) x Percent PM smaller than PM10
4. PM2.5 emissions (lb/hr) = Drift mass flow rate (lb/hr) x TDS (ppm)/(106) x Percent PM smaller than PM2.5
5. Annual TSP/PM10/PM2.5 emission rate (ton/yr) = Hourly emission rate (lb/hr) x 8,760 (hours/yr)/(2000 lb/ton).

Reference

J. Reisman and G. Frisbie, Calculating Realistic PM10 Emissions from Cooling Towers, Presented at Air & Waste Management Association Annual Conference. (June 2001)

Cooling Tower Particle Size Distribution

EPRI Droplet Diameter[1] (μm)	EPRI % Mass Smaller[1]	Droplet Volume (μm^3)	Droplet Mass (μg)	Particle Mass (Solids) (μg)	Solid Particle Volume (μm^3)	Solid Particle Diameter (μm)
10	0	5.24E+02	5.24E-04	1.05E-06	4.76E-01	0.969
20	0.196	4.19E+03	4.19E-03	8.38E-06	3.81E+00	1.937
25.81	0.213	9.00E+03	9.00E-03	1.80E-05	8.18E+00	2.500
30	0.226	1.41E+04	1.41E-02	2.83E-05	1.29E+01	2.906
40	0.514	3.35E+04	3.35E-02	6.70E-05	3.05E+01	3.875
50	1.816	6.54E+04	6.54E-02	1.31E-04	5.95E+01	4.844
60	5.702	1.13E+05	1.13E-01	2.26E-04	1.03E+02	5.812
70	21.348	1.80E+05	1.80E-01	3.59E-04	1.63E+02	6.781
90	49.812	3.82E+05	3.82E-01	7.63E-04	3.47E+02	8.719
103.23	63.501	5.76E+05	5.76E-01	1.15E-03	5.24E+02	10.000
110	70.509	6.97E+05	6.97E-01	1.39E-03	6.34E+02	10.656
130	82.023	1.15E+06	1.15E+00	2.30E-03	1.05E+03	12.593
150	88.012	1.77E+06	1.77E+00	3.53E-03	1.61E+03	14.531
180	91.032	3.05E+06	3.05E+00	6.11E-03	2.78E+03	17.437
210	92.468	4.85E+06	4.85E+00	9.70E-03	4.41E+03	20.343
240	94.091	7.24E+06	7.24E+00	1.45E-02	6.58E+03	23.250
270	94.689	1.03E+07	1.03E+01	2.06E-02	9.37E+03	26.156
300	96.288	1.41E+07	1.41E+01	2.83E-02	1.29E+04	29.062
350	97.011	2.24E+07	2.24E+01	4.49E-02	2.04E+04	33.906
400	98.34	3.35E+07	3.35E+01	6.70E-02	3.05E+04	38.749
450	99.071	4.77E+07	4.77E+01	9.54E-02	4.34E+04	43.593
500	99.071	6.54E+07	6.54E+01	1.31E-01	5.95E+04	48.436
600	100	1.13E+08	1.13E+02	2.26E-01	1.03E+05	58.124

1. Test data provided by Brentwood Industries for cooling tower with 0.0003% drift rate. The use of this data is conservative as it can be reasonably expected that a cooling tower with a 0.0003% drift rate will produce smaller droplets than one with a 0.0005% drift rate.

2. Highlights indicate interpolated values to determine $PM_{10}/PM_{2.5}$ speciation.

Reference

J. Reisman and G. Frisbie, Calculating Realistic PM10 Emissions from Cooling Towers, Presented at Air & Waste Management Association Annual Conference. (June 2001)

Emission Calculations

CCCT Lube Oil Demister Vent Potential Fugitive Emissions

CT/ST Lube Oil Demister Vent Data

Number of CT/ST	6	
Oil Mist Loading	7	mg/m^3
Oil Mist Loading	4.41E-07	lb/acf
Oil Mist Fan Vent Flow Rate	500	cfm

Fugitive VOC Emissions

Pollutant	Potential Emissions Each CT/ST[1,3] (lb/hr)	(tpy)	Potential Emissions All CCCT/ST[2,4] (lb/hr)	(tpy)
$TSP/PM_{10}/PM_{2.5}$ (total)	0.0	0.1	0.1	0.3
VOC	0.0	0.1	0.1	0.3

1. Emission factor per turbine (lb/hr) = Oil mist loading (lb/acf) * Oil Mist Fan Vent Flow Rate (cfm) * (60 min/hr)
2. Emission factor, all turbines (lb/hr) = Oil mist loading (lb/acf) * Oil Mist Fan Vent Flow Rate (cfm) * (60 min/hr) * Total Number of Combustion and Steam Turbines
3. Emissions per turbine (ton/yr) = Emission factor (lb/hr) * Hours of Operation (8,760 hr/yr) * (ton/2000 lb)
4. Emissions, all turbines (ton/yr) = Emission factor (lb/hr) * Hours of Operation (8,760 hr/yr) * (ton/2000 lb) * Total Number of Combustion and Steam Turbines

Conversion Factors	
0.45359237	kg/lb
0.3048	m/ft

Emergency Fire Water Pump Engine Potential NSR-Regulated and HAP Emissions

Fire Water Pumps:	**FP01, FP02**		
Engine Power	371	bhp	
Hours of Operation	500	hr/yr	
Heating Value of Diesel	19,300	Btu/lb	Per AP-42, Section 3.3, Table 3.3-1 footnote.
Power Conversion	7,000	Btu/hp-hr	Per AP-42, Section 3.3, Table 3.3-1 footnote.
Heat Input	2.60	MMBtu/hr, input	
Number of FWP Engines	2		

Criteria and GHG Pollutant Emissions

Pollutant	Emission Factor[1]	Units	Potential Emissions (each FWP) (lb/hr)	Potential Emissions (each FWP) (tpy)[4]	Potential Emissions (both FWP) (lb/hr)	Potential Emissions (both FWP) (tpy)[4]
CO	1.70	lb/hr	1.70	0.43	3.40	0.85
NO_X	1.98	lb/hr	1.98	0.50	3.96	0.99
TSP	0.10	lb/hr	0.10	0.03	0.20	0.05
PM_{10}	0.10	lb/hr	0.10	0.03	0.20	0.05
$PM_{2.5}$	0.10	lb/hr	0.10	0.03	0.20	0.05
SO_2[2]	0.00	lb/hp-hr	0.76	0.19	1.52	0.38
VOC	0.13	lb/hr	0.13	0.03	0.25	0.06
CO_2[3]	342.41	lb/hr	342.41	85.60	684.83	171.21
CH_4[3]	0.01	lb/hr	0.01	0.00	0.03	0.01
N_2O[3]	0.00	lb/hr	0.00	0.00	0.01	0.00

1. CO, NO_X, and TSP/PM_{10}/$PM_{2.5}$ emissions standards for Tier 3 stand-by emergency use engines. VOC emissions taken from a Cummi

2. Per AP-42 Section 3.3, Table 3.3-1 for diesel fuel.

3. Calculated using 40 CFR 98, Subpart C, Tables C-1 and C-2 default pollutant emission factors for No. 2 fuel oil, fire pump fuel consumption, and the following values for diesel fuel per AP-42 Section 3.4: 19,300 Btu/lb, and 7.1 lb/gal.
4. Emissions in tons per year calculated assuming 500 hours of operation annually.

Toxic/Hazardous Air Pollutant Emissions

Pollutant	Emission Factor (lb/MMBtu)	Potential Emissions (each FWP) (lb/hr)[2]	Potential Emissions (each FWP) (tpy)[3]	Potential Emissions (both FWP) (lb/hr)[2]	Potential Emissions (both FWP) (tpy)[3]
1,3-Butadiene	3.9E-05	1.0E-04	2.5E-05	2.0E-04	5.1E-05
Acenaphthene	1.4E-06	3.7E-06	9.2E-07	7.4E-06	1.8E-06
Acenaphthylene	5.1E-06	1.3E-05	3.3E-06	2.6E-05	6.6E-06
Acetaldehyde	7.7E-04	2.0E-03	5.0E-04	4.0E-03	1.0E-03
Acrolein	9.3E-05	2.4E-04	6.0E-05	4.8E-04	1.2E-04
Anthracene	1.9E-06	4.9E-06	1.2E-06	9.7E-06	2.4E-06
Benzene	9.3E-04	2.4E-03	6.1E-04	4.8E-03	1.2E-03
Benz(a)anthracene	1.7E-06	4.4E-06	1.1E-06	8.7E-06	2.2E-06
Benzo(a)pyrene	1.9E-07	4.9E-07	1.2E-07	9.8E-07	2.4E-07
Benzo(b)fluoranthene	9.9E-08	2.6E-07	6.4E-08	5.1E-07	1.3E-07
Benzo(g,h,i)perylene	4.9E-07	1.3E-06	3.2E-07	2.5E-06	6.3E-07
Benzo(k)fluoranthene	1.6E-07	4.0E-07	1.0E-07	8.1E-07	2.0E-07
Chrysene	3.5E-07	9.2E-07	2.3E-07	1.8E-06	4.6E-07
Dibenzo(a,h)anthracene	5.8E-07	1.5E-06	3.8E-07	3.0E-06	7.6E-07
Fluoranthene	7.6E-06	2.0E-05	4.9E-06	4.0E-05	9.9E-06
Fluorene	2.9E-05	7.6E-05	1.9E-05	1.5E-04	3.8E-05
Formaldehyde	1.2E-03	3.1E-03	7.7E-04	6.1E-03	1.5E-03
Indeno(1,2,3-cd)pyrene	3.8E-07	9.7E-07	2.4E-07	1.9E-06	4.9E-07
Naphthalene	8.5E-05	2.2E-04	5.5E-05	4.4E-04	1.1E-04
Phenanthrene	2.9E-05	7.6E-05	1.9E-05	1.5E-04	3.8E-05
Pyrene	4.8E-06	1.2E-05	3.1E-06	2.5E-05	6.2E-06
Toluene	4.1E-04	1.1E-03	2.7E-04	2.1E-03	5.3E-04
Xylenes	2.9E-04	7.4E-04	1.9E-04	1.5E-03	3.7E-04
Total HAP		**1.0E-02**	**2.5E-03**	**2.0E-02**	**5.0E-03**
Highest Single HAP		**3.1E-03**	**7.7E-04**	**6.1E-03**	**1.5E-03**

1. Per AP-42 Section 3.3, October 1996.
2. Emissions (lb/hr) calculated assuming heat input capacity of 2.1 MMBtu/hr.
3. Emissions in tons per year calculated assuming 500 hours of operation annually

Emergency Diesel Generator Emissions

Emergency Generators:	**EG01 & EG02**		
Engine Power	1,006	hp, output	
Hours of Operation	500	hr/yr	
Heating Value of Diesel	19,300	Btu/lb	Per AP-42, Section 3.3, Table 3.3-1 footnote.
Power Conversion	7,000	Btu/hp-hr	Per AP-42, Section 3.3, Table 3.3-1 footnote.
Heat Input	7.04	MMBtu/hr, input	
Number of Emergency Generators	2		

Criteria and GHG Pollutant Emissions

Pollutant	Emission Factor[1]	Units	Potential Emissions (each generator) (lb/hr)	Potential Emissions (each generator) (tpy)[4]	Potential Emissions (both generators) (lb/hr)	Potential Emissions (both generators) (tpy)[4]
CO	5.80	lb/hr	5.8	1.5	11.6	2.9
NO_X	10.60	lb/hr	10.6	2.7	21.2	5.3
TSP	0.33	lb/hr	0.3	0.1	0.7	0.2
PM_{10}	0.33	lb/hr	0.3	0.1	0.7	0.2
$PM_{2.5}$	0.33	lb/hr	0.3	0.1	0.7	0.2
SO_2[2]	0.00001	lb/hp-hr	0.0122	0.0	0.0	0.0
VOC	0.20	lb/hr	0.2	0.1	0.4	0.1
CO_2[3]	1197.60	lb/hr	1197.6	299.4	2395.2	598.8
CH_4[3]	0.05	lb/hr	0.0	0.0	0.1	0.0
N_2O[3]	0.01	lb/hr	0.0	0.0	0.0	0.0

1. CO, NO_X, and TSP/PM_{10}/$PM_{2.5}$ emissions standards for Tier 3 stand-by emergency use engines. VOC emissions taken from a Cummins guarantee for a similarly size engine.

2. Emission factor calculated per AP-42 Section 3.4, Table 3.4-1 footnote d, assuming use of ULSD (<0.0015% sulfur).

3. Emission factor calculated using 40 CFR 98, Subpart C, Tables C-1 and C-2 default pollutant emission factors for No. 2 fuel oil, emergency generator fuel consumption, and the following values for diesel fuel per AP-42 Section 3.4: 19,300 Btu/lb, and 7.1 lb/gal.

4. Emissions in tons per year calculated assuming 500 hours of operation annually.

Toxic/Hazardous Air Pollutant Emissions

Pollutant	Emission Factor[1] (lb/MMBtu)	Potential Emissions (each generator) (lb/hr)[2]	Potential Emissions (each generator) (tpy)[3]	Potential Emissions (both generators) (lb/hr)[2]	Potential Emissions (both generators) (tpy)[3]
Acenaphthene	4.7E-06	3.3E-05	8.2E-06	6.6E-05	1.6E-05
Acenaphthylene	9.2E-06	6.5E-05	1.6E-05	1.3E-04	3.2E-05
Acetaldehyde	2.5E-05	1.8E-04	4.4E-05	3.5E-04	8.9E-05
Acrolein	7.9E-06	5.5E-05	1.4E-05	1.1E-04	2.8E-05
Anthracene	1.2E-06	8.7E-06	2.2E-06	1.7E-05	4.3E-06
Benzene	7.8E-04	5.5E-03	1.4E-03	1.1E-02	2.7E-03
Benz(a)anthracene	6.2E-07	4.4E-06	1.1E-06	8.8E-06	2.2E-06
Benzo(a)pyrene	2.6E-07	1.8E-06	4.5E-07	3.6E-06	9.0E-07
Benzo(b)fluoranthene	1.1E-06	7.8E-06	2.0E-06	1.6E-05	3.9E-06
Benzo(g,h,i)perylene	5.6E-07	3.9E-06	9.8E-07	7.8E-06	2.0E-06
Benzo(k)fluoranthene	2.2E-07	1.5E-06	3.8E-07	3.1E-06	7.7E-07
Chrysene	1.5E-06	1.1E-05	2.7E-06	2.2E-05	5.4E-06
Dibenzo(a,h)anthracene	3.5E-07	2.4E-06	6.1E-07	4.9E-06	1.2E-06
Fluoranthene	4.0E-06	2.8E-05	7.1E-06	5.7E-05	1.4E-05
Fluorene	1.3E-05	9.0E-05	2.3E-05	1.8E-04	4.5E-05
Formaldehyde	7.9E-05	5.6E-04	1.4E-04	1.1E-03	2.8E-04
Indeno(1,2,3-cd)pyrene	4.1E-07	2.9E-06	7.3E-07	5.8E-06	1.5E-06
Naphthalene	1.3E-04	9.2E-04	2.3E-04	1.8E-03	4.6E-04
Phenanthrene	4.1E-05	2.9E-04	7.2E-05	5.7E-04	1.4E-04
Pyrene	3.7E-06	2.6E-05	6.5E-06	5.2E-05	1.3E-05
Toluene	2.8E-04	2.0E-03	4.9E-04	4.0E-03	9.9E-04
Xylenes	1.9E-04	1.4E-03	3.4E-04	2.7E-03	6.8E-04
Total HAP		**1.1E-02**	**2.8E-03**	**2.2E-02**	**5.5E-03**
Highest Single HAP		**5.5E-03**	**1.4E-03**	**1.1E-02**	**2.7E-03**

1. Per AP-42 Section 3.4 (Table 3.4-3 and 3.4-4), October 1996.

2. Emissions (lb/hr) calculated assuming heat input capacity of 7.04 MMBtu/hr.

3. Emissions in tons per year calculated assuming 500 hours of operation annually.

Emission Calculations

Storage Tank Potential Fugitive VOC Emissions

Tank ID	Tank Description	Quantity	Volume[1] (gal)	Contains VOC/HAP?	Throughput[2,3,4] (gal/yr)	Turnovers	TANKS 4.0 VOC Emissions (tpy)
TK09-TK10	Fire Pump ULSD Tank	2	70	Yes	7,663	109.5	< 0.01
TK07-TK08	Emergency Generator ULSD Tank	2	550	Yes	26,800	48.7	< 0.01
TK11	Vehicle Gasoline Tank	1	650	Yes	33,800	52.0	0.11
TK12	Vehicle Diesel Tank	1	650	Yes	33,800	52.0	< 0.01
TK01-TK06	Turbine Lube Oil Tanks	6	6,800	Yes	81,600	12.0	< 0.01
TK50	Water Pretreatment Plant Emergency Generator ULSD Tank	1	300	No	52,300	174.3	< 0.01
Total							**0.11**

1. Design specifications.
2. ULSD tanks' throughput based on engine hourly fuel usage and 500 operating hours per year.
3. Vehicle diesel and gasoline tanks' throughput based on conservative assumption of 52 turnovers per year.
4. Lube oil tanks' throughput based on conservative assumption of 12 turnovers per year.

Emergency Diesel Generator Emissions - Water Treatment Plant Emergency Generator

Emergency Generator:	**EG03**		
Engine Power	2,012	hp, output	
Hours of Operation	500	hr/yr	
Heating Value of Diesel	19,300	Btu/lb	Per AP-42, Section 3.3, Table 3.3-1 footnote.
Power Conversion	7,000	Btu/hp-hr	Per AP-42, Section 3.3, Table 3.3-1 footnote.
Heat Input	14.08	MMBtu/hr, input	
Number of Emergency Generators	1		

Criteria and GHG Pollutant Emissions

Pollutant	Emission Factor[1]	Units	Potential Emissions (lb/hr)	(tpy)[4]
CO	1.95	lb/hr	1.95	0.49
NO_X	2.57	lb/hr	2.57	0.64
TSP	0.13	lb/hr	0.13	0.03
PM_{10}	0.13	lb/hr	0.13	0.03
$PM_{2.5}$	0.13	lb/hr	0.13	0.03
SO_2[2]	0.00001	lb/hp-hr	0.02	0.01
VOC	0.49	lb/hr	0.49	0.12
CO_2[3]	2337.11	lb/hr	2337.11	584.28
CH_4[3]	0.09	lb/hr	0.09	0.02
N_2O[3]	0.02	lb/hr	0.02	0.005

1. Unless otherwise noted, emission factors provided manufacturer specifications.

2. Emission factor calculated per AP-42 Section 3.4, Table 3.4-1 footnote d, assuming use of ULSD (<0.0015% sulfur).

3. Emission factor calculated using 40 CFR 98, Subpart C, Tables C-1 and C-2 default pollutant emission factors for No. 2 fuel oil, emergency generator fuel consumption, and the following values for diesel fuel per AP-42 Section 3.4: 19,300 Btu/lb, and 7.1 lb/gal.

4. Emissions in tons per year calculated assuming 500 hours of operation annually.

Toxic/Hazardous Air Pollutant Emissions

Pollutant	Emission Factor[1] (lb/MMBtu)	Potential Emissions (lb/hr)[2]	(tpy)[3]
Acenaphthene	4.7E-06	6.6E-05	1.6E-05
Acenaphthylene	9.2E-06	1.3E-04	3.2E-05
Acetaldehyde	2.5E-05	3.5E-04	8.9E-05
Acrolein	7.9E-06	1.1E-04	2.8E-05
Anthracene	1.2E-06	1.7E-05	4.3E-06
Benzene	7.8E-04	1.1E-02	2.7E-03
Benz(a)anthracene	6.2E-07	8.8E-06	2.2E-06
Benzo(a)pyrene	2.6E-07	3.6E-06	9.0E-07
Benzo(b)fluoranthene	1.1E-06	1.6E-05	3.9E-06
Benzo(g,h,i)perylene	5.6E-07	7.8E-06	2.0E-06
Benzo(k)fluoranthene	2.2E-07	3.1E-06	7.7E-07
Chrysene	1.5E-06	2.2E-05	5.4E-06
Dibenzo(a,h)anthracene	3.5E-07	4.9E-06	1.2E-06
Fluoranthene	4.0E-06	5.7E-05	1.4E-05
Fluorene	1.3E-05	1.8E-04	4.5E-05
Formaldehyde	7.9E-05	1.1E-03	2.8E-04
Indeno(1,2,3-cd)pyrene	4.1E-07	5.8E-06	1.5E-06
Naphthalene	1.3E-04	1.8E-03	4.6E-04
Phenanthrene	4.1E-05	5.7E-04	1.4E-04
Pyrene	3.7E-06	5.2E-05	1.3E-05
Toluene	2.8E-04	4.0E-03	9.9E-04
Xylenes	1.9E-04	2.7E-03	6.8E-04
Total HAP		**2.2E-02**	**5.5E-03**
Highest Single HAP		**1.1E-02**	**2.7E-03**

1. Per AP-42 Section 3.4 (Table 3.4-3 and 3.4-4), October 1996.

2. Emissions (lb/hr) calculated assuming heat input capacity of 14.08 MMBtu/hr.

3. Emissions in tons per year calculated assuming 500 hours of operation annually.

Emission Calculations

Lime Silo Bin Vent Emission Calculations

Lime Silo Bin Vent Data

0.005	Outlet Grain loading (gr/dscf)
600	Flow Rate (dscfm)
20	Maximum Material Throughput (ton/hr)
7,000	grains/lb

Controlled TSP/PM_{10}/$PM_{2.5}$ potential to emit[1] (lb/hr) =	**0.03**
Controlled TSP/PM_{10}/$PM_{2.5}$ potential to emit[2] (tpy) =	**0.11**
Uncontrolled TSP potential to emit[3] (lb/hr) =	**0.15**
Uncontrolled PM_{10} potential to emit[3] (lb/hr) =	**0.07**
Uncontrolled $PM_{2.5}$ potential to emit[3] (lb/hr) =	**0.01**
Uncontrolled TSP potential to emit[4] (lb/ton) =	**7.55E-03**
Uncontrolled PM_{10} potential to emit[4] (lb/ton) =	**3.57E-03**
Uncontrolled $PM_{2.5}$ potential to emit[4] (lb/ton) =	**5.41E-04**

1. Controlled PTE (lb/hr) = Flow Rate (scfm) x Outlet Grain Loading (gr/dscf) x 1 lb/7,000 grains x 60 min/hr
2. Controlled PTE (ton/yr) = Controlled potential to emit (lb/hr) x 8760 hr/yr x 1 ton/2,000 lb
3. Uncontrolled PTE (lb/hr) calculated based on lb/ton emission factor and maximum material throughput (ton/hr).
4. Uncontrolled PTE (lb/ton) calculated based on AP-42, Section 13.2.4, equation 1. Assumed minimum moisture content and minimal wind speed.

Fugitive Circuit Breaker SF_6 Emissions

Description	Number of Breakers[1]	Amount of SF_6 Per Breaker[1] (lb)	SF_6 Leak Rate[2] (%/yr)	SF_6 Emission Rate (tpy)	CO_2e (tpy)
GHG Fugitive Equipment Leaks	6	60	0.5	9.0E-04	21.5

1. Design specification.
2. Proposed BACT limit

Methodology

SF_6 Emission Rate (tpy) = Number of Breakers * Amount of SF_6 Per Breaker (lb) * SF_6 Leak Rate (%/yr) * 1ton/2000lb

CO_2e = SF_6 Emission Rate (tpy) * Global Warming Potential for SF_6 (23,900)

GWP - SF_6 (per http://www.epa.gov/highgwp/magnesium-sf6/basic.html or Table A-1 of 40 CFR 98)

23,900

Indiana Department of Environmental Management
Office of Air Quality

Appendix B – BACT Analyses
Technical Support Document (TSD)
Prevention of Significant Deterioration (PSD)

Source Background and Description

Source Name:	**St. Joseph Energy Center, LLC**
Source Location:	**Corner of Walnut and Edison Roads, New Carlisle, Indiana 46552**
County:	**St. Joseph**
SIC Code:	**4911**
Operation Permit No.:	**T 141-31003-00579**
Operation Permit Issuance Date:	**Yet to be issued**
Permit Reviewer:	**Josiah Balogun**

Proposed Construction

St. Joseph Energy Center, LLC (SJEC) is proposing to install a new source in St. Joseph County. The source is proposing the construction and operation of a nominal 1,350 megawatt (MW) combined cycle combustion turbine (CCCT) electric generating facility (CCCT Facility). The proposed CCCT Facility will consist of a nominal net 1,350 MW natural gas-fired CCCT operation that includes two natural gas-fired 2 x1 CCCT blocks and ancillary equipment. A water treatment facility will be constructed on-site to supply SJEC operations. This facility will be operated by the town of New Carlisle, but is considered as part of the CCCT Facility.

St. Joseph Energy Center, LLC is required to undergo a review of control technology for pollutants above PSD threshold and significant levels under Federal and State Prevention of Significant Deterioration (PSD) Regulations.

St. Joseph Energy Center, LLC is located at the Corner of Walnut and Edison Roads, New Carlisle, Indiana, in St. Joseph County. SJEC submitted a PSD and Title V operating permit application to IDEM, OAQ on October 3, 2011,

Requirement for Best Available Control Technology (BACT)

326 IAC 2-2 requires a best available control technology (BACT) review to be performed on the proposed New Source Review because the new construction has the potential to emit CO emissions greater than 100 tons per year, which exceeds the PSD threshold and significant levels for this pollutant. The BACT review also addressed the following pollutants: PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, NOx, H_2SO_4 and Green House Gases that exceeded the PSD significant levels.

See Appendix A – Emission Calculations – of this TSD for detailed Potential to Emit (PTE) calculations.

Proposed New Emission Units

326 IAC 2-2 requires a best available control technology (BACT) review to be performed on the proposed emission units:

(a) Four (4) natural gas-fired combined cycle combustion turbines, identified as units CCCT1, CCCT2, CCCT3, and CCCT4, permitted in 2012, each with a combustion turbine equipped with dry low NOx burners, natural gas fired duct burners, and a heat recovery steam generator identified as HRSG1, HRSG2, HRSG3, and HRSG4, NOx emissions controlled by four (4) selective catalytic reduction (SCR) systems (SCR01, SCR02, SCR03 and SCR04), CO and VOC emissions controlled by oxidation catalyst systems (CAT01, CAT02, CAT03 and CAT04) and exhausting to stacks CCCT01, CCCT02, CCCT03, and CCCT04, respectively. Each stack has continuous emissions monitors (CEMS) for NOx and CO. The nominal heat input for each CCCT is 2,300 MMBtu/hr (higher heating value (HHV)). The combined nominal power output is 1,350 megawatts (MW).

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

(b) Two (2) natural gas fired auxiliary boilers, identified as B001 and B002, permitted in 2012, each, with a maximum heat input capacity of 80 MMBtu/hr (HHV), equipped with low NOx burners (LNB) with flue gas recirculation (FGR) to reduce NOx emissions, and exhausting to stacks B001 and B002. Under 40 CFR Part 60, Subpart Dc, the auxiliary boiler is considered a steam generating unit.

(c) One (1) emergency diesel generator, nominally rated at 2012 horsepower, identified as EG03, permitted in 2012, exhausting through one (1) vent, identified as EG03. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generator is considered a new affected source.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generator is considered a new affected source.]

(d) Two (2) firewater pump engines, each nominally rated at 371 brake horsepower (bph) and identified as FP01 and FP02, permitted in 2012, exhausting through two (2) vents, identified as FP01 and FP02, respectively. [Under 40 CFR 60, Subpart IIII, the firewater pump engines are considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the firewater pump engines are considered new affected sources.]

(e) Two (2) emergency diesel generators, each nominally rated at 1,006 horsepower, identified as EG01 and EG02, permitted in 2012, exhausting through two (2) vents, identified as EG01 and EG02, respectively. [Under 40 CFR 60, Subpart IIII, the emergency diesel fired generators are considered new affected sources.][Under 40 CFR 63, Subpart ZZZZ, the emergency diesel fired generators are considered new affected source.]

(f) Two (2) cooling towers, each nominally rated with a circulation rate of 170,000 gpm , identified as CT01 and CT02, permitted in 2012, with high efficiency drift/mist eliminators, and exhausting through ten vents each, identified as CT01A – CT01J and CT02A – CT02J.

(g) Six (6) Turbine Lube Demister Vents, identified as DM01 - DM06, permitted in 2012, exhausting through vents DM01 – DM06.

(h) Six (6) Turbine Lube Oil storage tanks, identified as TK01 - TK06, permitted in 2012, each with a nominal capacity of 6,800 gallons.

(i) Two (2) Emergency Generator ULSD Tanks, identified as TK07 and TK08, permitted in 2012, each with a nominal capacity of 550 gallons.

(j) Two (2) Fire Pump Engine ULSD Tanks, identified as TK09 and TK10, permitted in 2012, each with a nominal capacity of 70 gallons.

(k) One (1) Vehicle Gasoline dispensing Tank, identified as TK11, permitted in 2012, with a nominal capacity of 650 gallons, equipped with submerged fill and stage 1 vapor balance.

(l) One (1) Vehicle Diesel Tank, identified as TK12, permitted in 2012, with a nominal capacity of 650 gallons.

(m) One (1) Emergency Generator ULSD Tank, identified as TK50, permitted in 2012, with a nominal capacity of 300 gallons;

(n) Six (6) Electrical Circuit Breakers containing sulfur hexafluoride (SF_6) identified as emissions unit SF6, permitted in 2012, with fugitive GHG emissions;

Summary of the Best Available Control Technology (BACT) Process

BACT is a mass emission limitation based on the maximum degree of pollution reduction of emissions, which is achievable on a case-by-case basis. BACT analysis takes into account the energy, environmental, and economic impacts on the source. These reductions may be determined through the application of available control techniques, process design, work practices, and operational limitations. There will still be air pollution from this project; however, St. Joseph Energy Center, LLC (SJEC) will be required to demonstrate that the emissions will be reduced to maximum extent.

Federal EPA generally requires an evaluation that follows a “top down” process. In this approach, the applicant identifies the best controlled similar source on the basis of controls required by regulation or permit, or controls achieved in practice. The highest level of control is then evaluated for technical feasibility. IDEM evaluates BACT based on a "top down" approach.

The five (5) basic steps of a top-down BACT analysis used by the Office of Air Quality (OAQ) to make BACT determinations are listed below:

Step 1: Identify Potential Control Technologies

The first step is to identify potentially “available” control options for each emission unit and for each pollutant under review. Available options should consist of a comprehensive list of those technologies with a potentially practical application to the emissions unit in question. The list should include lowest achievable emission rate (LAER) technologies and controls applied to similar source categories.

Step 2: Eliminate Technically Infeasible Options

The second step is to eliminate technically infeasible options from further consideration. To be considered feasible, a technology must be both available and applicable. It is important in this step that any presentation of a technical argument for eliminating a technology from further consideration be clearly documented based on physical, chemical, engineering, and source specific factors related to safe and successful use of the controls. Innovative control means a control that has not been demonstrated in a commercial application on similar units. Innovative

controls are normally given a waiver from the BACT requirements due to the uncertainty of actual control efficiency. IDEM evaluates any innovative controls if proposed by the source. Only available and proven control technologies are evaluated. A control technology is considered available when there are sufficient data indicating that the technology results in a reduction in emissions of regulated pollutants.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness
The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern. The ranked alternatives are reviewed in terms of control effectiveness (percent pollutant removed). If the highest ranked technology is proposed as BACT, it is not necessary to perform any further technical or economic evaluation, except, for the environmental analyses.

Step 4: Evaluate the Most Effective Controls and Document the Results
The fourth step begins with an evaluation of the remaining technologies under consideration for each pollutant of concern in regards to energy, environmental, and economic impacts for determining a final control technology. The highest ranked alternative is evaluated for environmental, energy and economic impacts specific to the proposed modification. If the analysis determines that the highest ranked control is not appropriate as BACT, due to any of the energy, environmental, and economic impacts, then the next most effective control is evaluated. The evaluation continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts. If the highest ranked technology is proposed as BACT, it is not necessary to perform any further technical, economic or environmental analysis for a greenhouse gas BACT. An Air Quality Impact Analysis would be required for a non-greenhouse gas BACT.

Step 5: Select BACT
The most effective option not eliminated in step 4 is BACT.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT – Combined Cycle Combustion Turbines CCCT1 - CCCT4

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.

Step 2: Eliminate Technically Infeasible Options

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 and that cannot be economically accommodated. 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 CCCTs 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 turbines (CCCT1-CCCT4) at this source.

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 CCCTs generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. Add-on control devices 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 turbines (CCCT1-CCCT4) at this source.

Wet scrubbers:
A wet scrubber is an air pollution control device that removes PM 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 PM. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream. In general, collection efficiency decreases as the PM 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 PM 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. Another disadvantage is that they generate waste in the form of a sludge which requires treatment and/or disposal. 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 CCCTs generate low Particulate emissions and have large exhaust flowrates, resulting in very low concentrations of Particulates. Add-on control devices 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 turbines (CCCT1-CCCT4) at this source.

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 CCCTs generate low Particulate emissions and have large exhaust flow rates, resulting in very low concentrations of Particulates. Add-on control devices 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 turbines (CCCT1-CCCT4) at this source.

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, 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 turbines (CCCT1-CCCT4) at this source.

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 turbines (CCCT1-CCCT4) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of PM, PM_{10} and $PM_{2.5}$ resulting from the operation of the combined cycle combustion turbines (CCCT1-CCCT4).

(1) Fuel Specifications

(2) Good Combustion Practices

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies. All limitations in parenthesis were not obtained from the RBLC but were calculated to provide a consistent basis for comparing emissions rates to the proposed project.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Combined Cycle Combustion Turbines (CCCT1 - CCCT4)**	**2,300 MMBtu/hr**	**$PM/PM_{10}/PM_{2.5}$: 18 pounds per hour and 0.0078 lbs/MMBtu, with duct firing based on 3-hr average** **15 pounds per hour and 0.0092 lbs/MMBtu without duct firing based on 3-hr average**	**Good Combustion Practice and Fuel Specification**
NC-9001	Richmond County Combustion Turbine Facility	04/02/2009	Combustion Turbines	2,225 CT 390 DB	0.0059 lb/MMBtu with duct firing, based on 3,1-hr average 0.0071 lb/MMBtu without duct firing, based on 3,1-hr average	Fuel Specification
NY-0095	Caithness Bellport Energy Center	5/10/2006		2,221 CT 494 DB	0.0055 lb/MMBtu without DB 0.0066 lb/MMBtu with DB	Fuel Specification
NJ-0043	Liberty Generating Station (State requirement, not PSD)	03/28/2002	*Combustion Turbines	2,964 CT	PM: 0.005 lb/MMBtu	Unknown
TX-0546	Pattillo Branch Power Company, LLC - Electric Generating Station	06/17/2009	Combustion Turbines	350 MW per CCCT 444 DB	PM/PM10: 0.012 lb/MMBtu based on 3-hr average	Fuel Specification
GA-0105	Mcintosh Combined Cycle Facility	04/17/2003	Combustion Turbines	140 MW 542 DB	PM: 0.03 lb/MMBtu	Fuel Specification
CA-9002	PG&E - Colusa Generating Station	09/29/2008	Combustion Turbines	172 MW per turbine	PM: 20 lb/hour (0.008 lb/MMBtu)	Fuel Specification
LA-0224	SWEPCO - Arsenal Hill Power Plant	3/20/2008	Combustion Turbines	180 MW, each	PM/PM10: 24.23 lb/hr (0.010 lb/MMBtu)	Good design/proper operation

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
TX-0590	Pondera Capital Management GP Inc., King Power Station	8/5/2010	*Combustion Turbines (SGT6-5000F)	1350 MW	*PM: 11.10 lb/hr	Low Sulfur fuel
			*Combustion Turbines (GE7FA	1350 MW	*PM: 19.80 lb/hr	
TX-0600	Lower Colorado River Authority Thomas C. Ferguson Power Plant	9/1/2011	*Combustion Turbines	195 MW, each	PM/PM10/PM2.5: 33.43 lb/hr based on 1-hr average	Low Sulfur fuel
VA-0308	Virginia Electric and Power - Warren County Facility	12/21/2010	Combustion Turbines	300 MW	PM10/PM2.5: 0.004 lb/MMBtu with duct burners based on 3-hr average 0.0027 without duct burner, based on 3-hr average	Good Combustion Practices
AZ-9001	Bowie Power Station, LLC	Unknown	Combustion Turbines	172 MW per turbine	PM10: 22 lb/hr (0.010 lb/MMBtu)	Good Combustion Practices and Fuel Specifications
WA-0315	Sumas Energy 2 Generation Facility	05/27/2003	*Combustion Turbines	334 MW per turbine	PM10: 573 lb/day/HRSG stack, based on 24-hr average	Good Combustion Practices and Fuel Specifications
CA-1097	Southern California Public Power Authority - Magnolia Power Plant	5/27/2003	Combustion Turbines	181 MW	PM10: 18 lb/day with DB (0.0079 lb/MMBtu)	Unknown
					PM10: 12 lb/day without DB (0.0071 lb/MMBtu)	
OK-0129	Associated Electric Cooperative, Inc. – Chouteau Power Plant	1/20/2009	Combustion Turbines	178 MW per turbine	PM10: 0.0035 lb/MMBtu, based on 24-hr average	Good Combustion Practices
CA-9001	Calpine – Russell City Energy Center	2/3/2010	*Combustion Turbines	2038.6 CT 200 DB	PM10: 0.0036 lb/MMBtu	Good Combustion Practices and Fuel Specification

Note: * Not yet constructed

The Calpine – Russell City Energy Center, Pondera Capital Management GP Inc. – King Power Station, and Lower Colorado River Authority – Thomas C. Ferguson Power Plant, have not yet been constructed. Therefore, these BACT limits have not been demonstrated.

The Sumas Energy 2 Generation Facility and Liberty Generating Station were never constructed and are not evaluated against the proposed project.

The limits for the Richmond County Combustion Turbine Facility do not have an associated testing requirement in the issued PSD permit. Therefore, these BACT limits have not been demonstrated.

The Southern California Public Power Authority – Magnolia Power Plant was permitted in a nonattainment area for PM_{10} and was issued state BACT limits established to meet LAER. Therefore, these limits are not evaluated against the proposed project.

The combustion turbines at the Caithness Bellport Energy Center are permitted to operate only at steady state loads of 75% or greater. To ensure optimal flexibility in responding to market demand for power, St. Joseph Energy has developed emission limits and conducted air dispersion modeling based on steady state operating loads as low as 47%. In addition, the Caithness Bellport Energy Center SO2 limits indicate access to natural gas with a sulfur content of 0.35 gr/100 scf, while St. Joseph Energy cannot assure access to natural gas with a sulfur content less than 0.75 gr/100 scf. Therefore, the limits for the Caithness Bellport Energy Center are not evaluated against this project.

The permit issued for the PG&E – Colusa Generating Station includes annual, daily, and hourly limits on PM_{10} emissions, but does not limit PM_{10} emissions on a lb/MMBtu basis. Based on emissions data presented in the permit application for the PG&E – Colusa Generating Station, PM_{10} emissions range from 0.008 lb/MMBtu at maximum load, to 0.011 lb/MMBtu at 50% load levels.

The Associated Electric Cooperative, Inc. – Chouteau Power Plant value is an outlier and is specific to the design of this facility. All other demonstrated limits for F-class turbines are not less than 0.0055 lb/MMBtu.

The limits in the Virginia Electric and Power - Warren County Facility are for G-class turbines, not F-class turbines like those for the proposed project.

The project site is based upon the development and construction, in stages, of two power blocks each rated at 600MW nominal output and capable of responding quickly to frequent changes in power demand for the local grid. The 600MW nominal power blocks were selected because they fit both the physical parameters of the available interconnection with the local grids and the assessment of the near term market demand.

The configuration of a 600MW nominal gas turbine combined cycle power block is a natural fit with “F” class combustion turbines. The desired capacity of 600MW’s can be provided at Summer ambient condition by combining two(2) “F” class combustion turbines (rated at just over 200MW at high ambient temperatures) combined with a single 200+ MW steam turbine and heat recovery steam generator with a modest amount of supplementary duct burner firing. This type of configuration represents the overwhelmingly most popular type planned and constructed in the North American market.

The “G” class combustion turbines differ from “F” in two important ways: a) the combustors fire at substantially higher temperatures, which fundamentally is the reason “G” machines have a somewhat higher thermal efficiency and b) the commercially available equipment is rated at 250MW nominal each unit. The larger 250MW unit rating does not fit the 600MW power block capacity. A “2on1” configuration would be too large at 750MW and a “1on1” too small at 400MW.

Also, the higher thermal efficiency "G" machines are primarily designed to operate more frequently at a steady base loaded condition and not be cycled up and down in MW load or on and off frequently. The "F" class machines are more thermally flexible and the power blocks more responsive to varying market demand and unit load cycling operation.

Based on the available interconnection with the local grid, the maximum load requirements established by near term market demand, and the need to respond quickly to frequent changes in power demand, use of "G" class combustion turbines are not suitable for this project and SJEC will utilize commercially proven F-class turbines.

St. Joseph Energy is proposing $PM/PM_{10}/PM_{2.5}$ emissions limits at 15 lb/hr and 0.0092 lb/MMBtu without duct burning and 18 lb/hr and 0.0078 MMBtu with duct burning based on vendor data. For a typical combustion turbine, the $PM/PM_{10}/PM_{2.5}$ emission rate in lb/MMBtu increases as turbine load decreases. Therefore, the proposed lb/hr emission rates are based on maximum load while the proposed lb/MMBtu emission rates are based on the minimum design load for that operating scenario. $PM/PM_{10}/PM_{2.5}$ emissions for CCCT include contributions from the combustion turbine, duct burner, and oxidation of sulfur in the fuel to sulfate particulate matter. Therefore, $PM/PM_{10}/PM_{2.5}$ potential to emit for the similar sized turbine can vary based on duct burner size, sulfur content guarantees for the available fuel, and the assumed sulfur to sulfate conversion rate. Therefore, the proposed emission rates are consistent with the recent BACT determinations in EPA's RACT/BACT/LAER clearinghouse such as the PG&E – Colusa Generating Station, given variations between duct burner sizes, natural gas sulfur content, and assumed fuel sulfur to sulfate conversion rates between these projects.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ emissions from the proposed combined cycle combustion turbines, identified as CCCT1 -CCCT4:

1. The PM, PM_{10} and $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as CCCT1 -CCCT4 shall not exceed 18 lb/hour and 0.0078 lb/MMBtu with duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

2. The PM, PM_{10} and $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as CCCT1 -CCCT4 shall not exceed 15 pounds per hour and 0.0092 lb/MMBtu without duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for the combined cycle combustion turbines (CCCT1-CCCT4).

1. The PM, PM_{10} and $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as CCCT1 -CCCT4 shall not exceed 18 lb/hour and 0.0078 lbs per MMBtu with duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

2. The PM, PM_{10} and $PM_{2.5}$ emissions from the combined cycle combustion turbines identified as CCCT1 -CCCT4 shall not exceed 15 pounds per hour and 0.0092 lbs per MMBtu without duct firing based on 3-hr average through the use of good combustion practices and fuel specification.

Sulfuric Acid (H_2SO_4) BACT – Combined Cycle Combustion Turbines CCCT1 - CCCT4

Step 1: Identify Potential Control Technologies

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

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 netural 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 turbines (CCCT1-CCCT4) 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 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 dry sorbent injection is not a technically feasible option for the combined cycle combustion turbines (CCCT1-CCCT4) 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 is 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 turbines (CCCT1-CCCT4) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of H_2SO_4 resulting from the operation of the combined cycle combustion turbines (CCCT1-CCCT4).

(1) Fuel Specifications

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed H_2SO_4 BACT determination along with the existing H_2SO_4 BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Combined Cycle Combustion Turbines (CCCT1 - CCCT4)**	**2,300 MMBtu/hr**	**H_2SO_4: 0.75 gr S/100 scf fuel sulfur**	**Fuel Specification**
FL-0304	FMPA - Cane Island Power Park	9/8/2008	Combustion Turbines	1,860 CT 600 DB	2 gr S/100 scf gas	Fuel Specification
FL-0263	FP&L - Turkey Point Fossil Plant	2/8/2005	Combustion Turbines	1,608 CT 495 DB	2 gr S/100 scf gas	Fuel Specification
TX-0546	Pattillo Branch Power Company, LLC - Electric Generating Plant	6/17/2009	Combustion Turbines	444 DB	2 gr S/100 scf gas	Fuel Specification
FL-9002	FP&L Company - Cape Canaveral Energy Center	7/23/2009	Combustion Turbines	2,586 CT 460 DB	2 gf S/100 scf gas	Fuel Specification

The proposed natural gas sulfur content limit of 0.75 gr S/100 scf is the most stringent limit for H_2SO_4 emissions. Note that H_2SO_4 emissions depend on the sulfur content of the natural gas available to the facility. The proposed facility will have access to natural gas from a single supplier for the region, and will not have the option to receive natural gas from any other source or require the supplier to provide lower sulfur content fuel. Since natural gas sulfur content is dependent on the supply available to that region, comparison of fuel sulfur content for natural gas from different regions, which the proposed site will not have access to, is not appropriate.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for H_2SO_4 emissions from the proposed combined cycle combustion turbines, identified as CCCT1 -CCCT4:

The H_2SO_4 emissions from the combined cycle combustion turbines identified as CCCT1 - CCCT4 shall not exceed 0.75 gr S/100 scf fuel sulfur through the use of fuel specification.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for H_2SO_4 for the combined cycle combustion turbines (CCCT1-CCCT4).

The H_2SO_4 emissions from the combined cycle combustion turbines identified as CCCT1 - CCCT4 shall be limited by a fuel sulfur limit of 0.75 gr S/100 scf fuel.

Carbon Monoxide (CO) BACT – Combined Cycle Combustion Turbines CCCT1 - CCCT4

Step 1: Identify Potential 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.

If add-on control technology is not feasible, an alternate method of control may be implemented.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, 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.

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 turbines at this source.

Recuperative Thermal Oxidizers
This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1,200^{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 turbines at this source.

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. Not included in RBLC for control of CO emissions from large combined cycle combustion turbines. 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 turbines at this source.

Catalytic Oxidizers

Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, 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 turbines at this source.

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 turbines at this source

Good Combustion Controls

Good combustion controls is a continued operation of the CCCT at the appropriate oxygen range and temperature to promote complete combustion and minimize CO formation. Because CO is essentially a by-product of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of CO emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. CO emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics.

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 turbines at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Oxidation Catalyst - 70-90% destruction efficiency

(2) Combustion Control

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination along with the existing CO BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Combined Cycle Combustion Turbines (CCCT1 - CCCT4)**	**2,300 MMBtu/hr**	**CO: 2.0 ppmvd @15% O_2, with duct burners based on 3-hr average**	**Oxidation Catalyst**
VA-0308	Virginia Electric and Power - Warren County Facility	12/21/2010	Combustion Turbines	2996 CT 500 DB	1.5 ppmvd @15% O_2, without duct burner, based on 1-hr average 2.4 ppmvd @15% O_2, with duct burner, based on 1-hr average	Oxidation Catalyst
CT-0151	Kleen Energy Systems, LLC	2/25/2008	Combustion Turbines	2136 CT 445 DB	0.9 ppmvd @15% O_2, without duct burner, based on 1-hr average 1.7 ppmvd @15% O_2, with duct burner, based on 1-hr average	Oxidation Catalyst
GA-0127	Georgia Power - McDonough	1/7/2008	Combustion Turbines	Unknown	1.8 ppmvd @15% O_2, based on 3-hr average	Oxidation Catalyst
GA-9001	Live Oaks Power Plant	4/8/2010	Combustion Turbines	1990 CT 359 DB	2.0 ppmvd @15% O_2, without duct burners based on 3-hr average 3.2 ppmvd @15% O_2, with duct burners based on a 3-hr average	Oxidation Catalyst
CA-9001	Calpine -	2/3/2010	Combustion	2038.6 CT	2.0 ppmvd	Oxidation

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
	Russell City Energy Center		Turbines	200DB	@15% O_2, based on 1-hr average	Catalyst
TX-0600	Lower Colorado River Authority Thomas C. Ferguson Power Plant	9/1/2011	Combustion Turbines	Unknown	4.0 ppmvd @15% O_2, based on 3-hr rolling at load > 60%, 6.0 ppmvd @15% O_2, based on 3-hr rolling at load < 60%	Oxidation Catalyst
VA-0308	Virginia Electric and Power - Warren County Facility	1/14/2008	Combustion Turbines	1717 CT 500 DB	2.5 ppmvd @15% O_2, with power augmentation and DB firing, based on 3-hr average	Oxidation Catalyst
AZ-0047	Dome Valley Energy Partners - Wellton Mohawk Generating Facility	12/1/2004	Combustion Turbines	Unknown	3.0 ppmvd @15% O_2, based on 3-hr average	Oxidation Catalyst
CA-9002	PG&E - Colusa Generating Station	9/29/2008	Combustion Turbines	1917.2 CT 688 DB	3.0 ppmvd @15% O_2, based on 3-hr average	Oxidation Catalyst
FL-0304	FMPA - Cane Island Power Park	9/8/2008	Combustion Turbines	1860 CT 600 DB	6.0 ppmvd @15% O_2 based on annual average 8.0 ppmvd @15% O_2 based on 24-hr average	Combustion Practices

As shown in the above table, the CO BACT emission limits range from a minimum of 0.9 ppmvd at 15% O_2 to greater than 6.0 ppmvd at 15% O_2, and the averaging periods range from a 1-hour average to a 30-day rolling average. The majority of the facilities with the most stringent CO BACT emission limits have installed oxidation catalysts for CO control; however, a recent permit identified in the table list good combustion practices as BACT for CO.

Based on a review of the emission limits achievable and recent BACT determinations for similar facilities, IDEM has determined that CO BACT for normal operation is a limit of 2.0 ppmvd at 15% O_2 on a 3-hour rolling average basis. The only facilities in the RBLC with more stringent emission limits are the Virginia Electric and Power Company – Warren County Facility, Kleen Energy Systems, and the Georgia Power McDonough Combined Cycle Generating Units. The permit for the Warren County facility provides a range of BACT limits that cover three different potential turbine manufacturers with two or three operating modes per manufacturer. Since receiving the original air permit, the Virginia Electric and Power Company has submitted a new application for the Warren County requesting revisions to the CO BACT limits in the current permit. Some of the modes are higher for CO than proposed for the SJEC CCCT facility, while others are lower. In aggregate, the limits are likely slightly lower than the SJEC CCCT facility, but

one limit is as high as 2.5 ppmvd. This substantial range of limits makes an accurate comparison with Warren County difficult. The permit for the McDonough Combined Cycle Generating Facility provides a BACT limit of 1.8 ppmvd at 15% O_2 on a 3-hour average basis during periods of operation with duct burners. This facility is under construction. This limit is slightly lower, but nearly equivalent to that identified as BACT for the SJEC CCCT facility. McDonough uses larger G-class turbines that are designed to operate at higher capacity factors than the SJEC units and thus are not directly comparable to the F-class units for the SJEC CCCT facility.

The “G” class combustion turbines differ from “F” in two important ways: a) the combustors fire at substantially higher temperatures; which fundamentally is the reason “G” machines have a somewhat higher thermal efficiency and b) the commercially available equipment is rated at 250MW nominal each unit. The larger 250MW unit rating does not fit the 600MW power block capacity. A “2on1” configuration would be too large at 750MW and a “1on1” too small at 400MW. Also, the higher thermal efficiency “G” machines are primarily designed to operate more frequently at a steady base loaded condition and not be cycled up and down in MW load or on and off frequently. The “F” class machines are more thermally flexible and the power blocks more responsive to varying market demand and unit load cycling operation.

Based on the available interconnection with the local grid, the maximum load requirements established by near term market demand, and the need to respond quickly to frequent changes in power demand, use of "G" class combustion turbines are not suitable for this project and SJEC will utilize commercially proven F-class turbines.

The permit for the Kleen Energy Systems facility in Middletown, Connecticut provides a BACT limit of 1.7 ppmvd at 15% O_2 on a 1-hour average basis during periods of operation with duct burners. The Kleen Energy Systems, LLC value is an outlier and is specific to the design of this facility. This limit is only slightly lower than that identified as BACT for the SJEC CCCT facility, and is reflective of the site-specific capabilities of this particular facility. Within the RBLC, all other demonstrated CO limits for F-class turbines are not less than 2.0 ppmv. Therefore the proposed limit of 2.0 ppmvd @15% O_2, with duct burners based on 3-hr average is consistent with the most stringent limit for this type of operation.

The proposed SJEC CCCT facility BACT limit of 2.0 ppmvd at 15% O_2 is consistent with other demonstrated permits limits reviewed in the RBLC database. Therefore, the proposed limit of 2.0 ppmvd at 15% O_2 on a 3-hour rolling average basis is appropriate for the proposed CCCTs.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for CO emissions from the proposed combined cycle combustion turbines, identified as CCCT1 -CCCT4:

(1) The CO emissions from the CCCT shall be controlled by catalytic oxidation

(2) The CO emissions shall not exceed 2.0ppmv @15% O2 based on a 3-hr average.

(3) The CO emissions from each of the turbines and the associated burners, excluding startup and shutdown periods, shall not exceed 407.5 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for CO for the combined cycle combustion turbines:

(1) The CO emissions from the CCCT shall be controlled by catalytic oxidation

(2) The CO emissions shall not exceed 2.0 ppmvd @15% O2 based on a 3-hour average.

Sulfur Dioxide (SO_2) BACT - Combined Cycle Combustion Turbines CCCT1 - CCCT4

Step 1: Identify Potential Control Technologies

Sulfur Dioxide (SO_2) emissions result from the oxidation of fuel-bound sulfur, with emissions dependent upon the sulfur content of the fuel. Sulfur Dioxide (SO_2) 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. Sulfur Dioxide (SO_2) emissions are not dependent upon combustion turbine properties such as size or burner design.

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. 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 netural 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 turbines (CCCT1-CCCT4) 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 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 SO_2 emissions for large combustion turbines. Technology has not been applied to natural gas combustion turbines due to very low SO_2 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 combined cycle combustion turbines (CCCT1-CCCT4) 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 SO_2 emissions. Fuel Specifications is included in RBLC for the control of SO_2 emissions from 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 turbines (CCCT1-CCCT4) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of SO_2 resulting from the operation of the combined cycle combustion turbines (CCCT1-CCCT4).

(1) Fuel Specifications

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed SO_2 BACT determination along with the existing SO_2 BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Combined Cycle Combustion Turbines (CCCT1 - CCCT4)**	**2,300 MMBtu/hr**	**SO_2: 0.75 gr S/100 scf fuel sulfur**	**Fuel Specification**
CA-9002	PG&E - Colusa Generating Station	9/29/2008	Combustion Turbines	1917.2CT 688 DB	0.3 gr S/100 cf gas	Fuel Specification
CA-9003	Sempra Energy Resources - Palomar Energy Project	Unknown	Combustion Turbines	Unknown	0.75 gr S/100 cf gas	Fuel Specification
FL-0304	FMPA - Cane Island Power Park	9/8/2008	Combustion Turbines	1860 CT 600 DB	2 gr S/100 cf gas	Fuel Specification
TX-0546	Pattillo Branch Power Company, LLC - Electric	6/17/2009	Combustion Turbines	444 DB	2 gf S/100 scf gas	Fuel Specification

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
	Generating Plant					
FL-9002	FP&L Company - Cape Canaveral Energy Center	7/23/2009	Combustion Turbines	2586 CT 460 DB	2 gf S/100 scf gas	Fuel Specification

The proposed CCCTs will be subject to NSPS KKKK. NSPS KKKK provides that either SO_2 emissions from any turbine must not exceed 0.90 lb/MWh of gross output, or fuels burned in the turbine must have sulfur content that is below the amount which would result in potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input. NSPS KKKK sets the floor of allowable SO_2 BACT limits. Based on review of the emission limits achievable, IDEM has determined that SO_2 BACT for normal operation is the use of fuels with a sulfur content no greater than 0.75 grains per 100 standard cubic feet. The lowest BACT limit in all of the permits reviewed is 0.3 grains per 100 standard cubic feet. The SO_2 emissions are based primarily on the sulfur content of the natural gas available in the pipeline. The natural gas used at the SJEC CCCT facility will have a sulfur content of 0.75 grains per 100 standard cubic feet. The proposed natural gas sulfur content limit of 0.75 gr S/100 scf is dependent on the sulfur content of the natural gas available to the facility.

The proposed facility will have access to natural gas from a single supplier for the region, and will not have the option to receive natural gas from any other source or require the supplier to provide lower sulfur content fuel. Therefore, the proposed BACT limit of the use of fuels with a sulfur content no greater than 0.75 grains per 100 standard cubic feet is appropriate.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for SO_2 emissions from the proposed combined cycle combustion turbines, identified as CCCT1 -CCCT4:

The SO_2 emissions from the combined cycle combustion turbines identified as CCCT1 -CCCT4 shall not exceed 0.75 gr S/100 scf fuel sulfur through the use of fuel specification.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for SO_2 for the combined cycle combustion turbines (CCCT1-CCCT4).

The SO_2 emissions from the combined cycle combustion turbines identified as CCCT1 -CCCT4 shall be limited by a fuel sulfur limit of 0.75 gr S/100 scf fuel.

Volatile Organic Compounds (VOCs) BACT – Combined Cycle Combustion Turbines CCCT1 - CCCT4

Emissions of volatile organic compounds (VOCs) 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.

If add-on control technology is not feasible, an alternate method of control may be implemented.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, 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 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.

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 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.

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. Not included in RBLC for control of CO emissions from large combustion turbines. 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 turbines at this source.

Catalytic Oxidizers

Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling VOC emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without 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 VOC emissions from 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 turbines at this source.

Flare

Although the VOC concentration is very low, the stream flow rate is very high. The low heating value of the stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NOx. Flares have not been utilized or demonstrated as a control device for 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 turbines at this source

Good Combustion Controls
Good combustion controls is a continued operation of the CCCT at the appropriate oxygen range and temperature to promote complete combustion and minimize VOC formation. Because VOC is essentially a by-product of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of VOC emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. VOC emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting VOC emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Controls is a technically feasible option for the combined cycle combustion turbines at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Oxidation Catalyst - 20-40% destruction efficiency

(2) Combustion Control

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination along with the existing VOC BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Combined Cycle Combustion Turbines (CCCT1 - CCCT4)**	**2,300 MMBtu/hr**	**1.0 ppmvd @15% O_2, without duct burners based on 3-hr average** **2.0 ppmvd @15% O_2, with duct burners based on 3-hr average**	**Oxidation Catalyst**
OK-0129	Associated Electric Cooperative, Inc. - Chouteau Power Plant	1/20/2009	Combustion Turbines	1882 CT 100 DB	0.3 ppmvd @15% O_2	Good Combustion Practices
VA-0308	Virginia Electric and Power - Warren County Facility	12/21/2010	Combustion Turbines	2996 CT 500 DB	0.7 ppmvd @15% O_2, without duct burners, based on 3-hr average,	Oxidation Catalyst

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
					1.6 ppmvd @15% O_2 with duct burners, based on 3-hr average	
CA-1144	Caithness Blythe II, LLC - Blythe Energy Project	4/25/2007	Combustion Turbines	Unknown	1 ppmvd @15% O_2, based on 1-hr average	Good Combustion Practices
ID-0018	Idaho Power Company Langley Gulch Power Plant	6/25/2010	Combustion Turbines	2134 CT 241.28 DB	2 ppmvd @15% O_2, based on 3-hr rolling, 11.5 ppmvd @15% O_2 based on 3-hr rolling average during low load events	Catalytic Oxidation
TX-0600	Lower Colorado River Authority Thomas C. Ferguson Power Plant	9/1/2011	Combustion Turbines	Unknown	2 ppmvd @15% O_2, based on 3-hr rolling	Catalytic Oxidation
FL-0303	FP&L - West County Energy Center	7/30/2008	Combustion Turbines	2333 CT 428 DB	1.2 ppmvd @15% O_2, based on 3-hr initial	Catalytic Oxidation
FL-0244	FP&L - Martin Plant	4/16/2003	Combustion Turbines	1600 CT 495 DB	1.3 ppmvd @15% O_2 without duct burners, 4 ppmvd at 15% O_2 with duct burners	Good Combustion Practices
AZ-0038	Gila Bend Power Generating Station	5/15/2002	Combustion Turbines	Unknown	2.8 ppmvd @15% O_2, based on 3-hr average	Good Combustion Practices
MN-0053	Minnesota Municipal Power Agency - Fairbault Energy Park	6/5/2007	Combustion Turbines	1758 CT 249 DB	1.5 ppmvd @15% O_2, without duct burners based on 3-hr average, 3 ppmvd at 15% O_2 with duct burners based on 3-hr average	Unknown
AZ-0043	Duke Energy Arlington Valley (AVEFII)	11/23/2003	Combustion Turbines	2333 CT (LHV) 428 DB (LHB)	1 ppmvd @15% O_2 without duct burners, based on 3-hr average 4 ppmvd @15% O_2 with duct burners, based on 3-hr average	Catalytic Oxidation

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
NJ-0043	Liberty Generating Station (State Requirement, not PSD)	3/28/2002	*Combustion Turbines	2964 CT	1 ppmvd @15% O_2	Catalytic Oxidation
FL-0285	Progress Energy Florida – Bartow Power Plant	1/26/2007	Combustion Turbines	2006 CT 500 DB	1.2 ppmvd @15% O_2 without duct burners, 1.5 ppmvd @15% O_2 with duct burners,	None required by permit
PA-0189	Connectiv Bethlehem (not PSD BACT)	1/16/2002	Combustion Turbines	Unknown	1.2 ppmvd @15% O_2	Unknown
FL-0263	FP&L – Turkey Point Fossil Plant	2/8/2005	Combustion Turbines	1608 CT (LHF) 495 DB (LHV)	1.3 ppmvd @15% O_2 without duct burners, based on 3-run average 1.9 ppmvd @15% O_2 with duct burners, based on 3-run average	Good Combustion Practices
FL-0245	FP&L – Manatee Plant Unit 3	4/15/2003	Combustion Turbines	1600 CT (LHV) 495 DB (LHV)	1.3 ppmvd @15% O_2 without duct burners 4 ppmvd @15% O_2 with duct burners	Good Combustion Practices
AR-0070	Genova Arkansas I, LLC	8/23/2002	Combustion Turbines	Unknown	1.4 ppmvd @15% O_2	Good Combustion Practices
LA-01157	Perryville Energy Partners, LLC – Perryville Energy Center	3/8/2002	Combustion Turbines	Unknown	1.4 ppmvd @15% O_2	Good Combustion Practices
NC-9001	Richmond County Combustion Turbine Facility	4/2/2009	Combustion Turbines	2225 CT 390 DB	1 ppmvd @15% O_2 without duct burners at 70-100% load 5 ppmvd @15% O_2 without duct burners at 60-70% load 3 ppmvd @15% O_2 with duct burners at 60-100% load	Good Combustion Practices

* Not yet constructed

The Caithness Blythe II, LLC project is in a state nonattainment area for ozone, requiring the source to obtain emission offsets for VOC. Therefore, this limit is not evaluated against the proposed project.

The limits for Connectiv Bethlehem were established to meet applicable requirements other than PSD-BACT requirements. Therefore, this limit is not evaluated against the proposed project.

The Liberty Generating Station was never constructed and is not evaluated against the proposed project.

The limits in the Virginia Electric and Power - Warren County Facility are for G-class turbines, not F-class turbines like those for the proposed project. Commercial operation is scheduled for late 2014 or early 2015. Therefore, BACT limits have not been demonstrated.

The limits for FP&L – West County Energy Center are for G-class turbines, not F-class turbines like those for the proposed project.

The “G” class combustion turbines differ from “F” in two important ways: a) the combustors fire at substantially higher temperatures; which fundamentally is the reason “G” machines have a somewhat higher thermal efficiency and b) the commercially available equipment is rated at 250MW nominal each unit. The larger 250MW unit rating does not fit the 600MW power block capacity. A “2on1” configuration would be too large at 750MW and a “1on1” too small at 400MW. Also, the higher thermal efficiency “G” machines are primarily designed to operate more frequently at a steady base loaded condition and not be cycled up and down in MW load or on and off frequently. The “F” class machines are more thermally flexible and the power blocks more responsive to varying market demand and unit load cycling operation.

Based on the available interconnection with the local grid, the maximum load requirements established by near term market demand, and the need to respond quickly to frequent changes in power demand, use of "G" class combustion turbines are not suitable for this project and SJEC will utilize commercially proven F-class turbines.

The Associated Electric Cooperative, Inc. – Chouteau Power Plant value is an outlier and is specific to the design of this facility. All other demonstrated limits for F-class turbines are not less than 1.0 ppmvd without duct burner firing. Therefore the proposed limit of 1.0 ppmvd @15% O_2, without duct burners and of 2.0 ppmvd @15% O_2, with duct burners based on 3-hr average is consistent with all other limits in the RBLC for this type of operation.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for VOC emissions from the proposed combined cycle combustion turbines, identified as CCCT1 -CCCT4:

(1) The VOC emissions from the CCCT shall be controlled by a catalytic oxidation.

(2) The VOC emissions shall not exceed 2.0 ppmvd @15% O_2, with duct burners based on 3-hr average.

(3) The VOC emissions shall not exceed 1.0 ppmvd @15% O_2, without duct burners based on 3-hr average.

(4) The VOCs emissions from each of the turbines and the associated burners, excluding startup and shutdown periods, shall not exceed 22.0 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for VOC for the combined cycle combustion turbines:

(1) The VOC emissions from the CCCTs shall be controlled by a catalytic oxidation

(2) The VOC emissions shall not exceed 2.0 ppmvd @15% O_2, with duct burners based on 3-hr average.

(3) The VOC emissions shall not exceed 1.0 ppmvd @15% O_2, without duct burners based on 3-hr average.

Nitrogen Oxide (NOx) BACT – Combined Cycle Combustion Turbines CCCT01 - CCCT04

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) Xonon Cool Combustion;

(e) Water/Steam Injection; and

(f) Low NOx Burners (LNB).

Add-on control technologies and combustion control approaches are discussed below.

Step 2: Eliminate Technically Infeasible Options

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. Temperatures 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 sootblower. Selective Catalytic Reduction (SCR) is included in RBLC for the control of NO_X emissions from large combustion turbines.
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 combined cycle combustion turbines at this source.

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 combined cycle combustion turbines at this source.

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 large combustion turbines. 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 combined cycle combustion turbines at this source.

Xonon Cool Combustion
Xonon Cool Combustion is a catalyst integrated into gas turbine combustors that limits the production of NO_X through temperature control also resulting in reduced emissions of CO and VOC. This control device is not included in RBLC for the control of NO_X emissions from large combustion turbines. This technology is not commercially available on large units; all commercial installations to date have been on small turbines in the range of 1-2 MW.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that Xonon Cool Combustion is not a technically feasible option for the combined cycle combustion turbines at this source.

Water/Steam Injection
Water/steam Injection acts as a heat sink, lowing combustion zone peak temperatures, resulting in a decrease in thermal NOx emissions. This result in a small efficiency penalty but an increase in power output and this control technology may increase CO and VOC emissions. The control technology is included in RBLC for the control of NO_X emissions from large combustion turbines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that Water/steam Injection is a technically feasible option for the combined cycle combustion turbines at this source.

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 includes 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 LNBs 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 is used, LNBs with staged combustion are subdivided into staged air burners and staged fuel burners.

Experience suggests that significant reductions 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 a low NOx burner is a technically feasible option for the combined cycle combustion turbines at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Selective Catalytic Reduction — (70-90% NOx Reduction)

(2) Selective Noncatalytic Reduction — (40-60% NOx Reduction)

(3) Low NOx Burner (LNB) — (40%-50% NOx Reduction)

(4) Water/Steam Injection — (30-50% 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 permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Combined Cycle Combustion Turbines (CCCT1 - CCCT4)**	**2,300 MMBtu/hr**	**NOx: 2.0 ppmvd @15% O_2, with duct burners based on 3-hr average**	**SCR and DLN Burners**
VA-0308	Virginia Electric and Power - Warren County Facility	12/21/2010	Combustion Turbines	2996 CT 500 DB	2.0 ppmvd @15% O_2, based on 1-hr average	DLN and SCR
FL-0303	FP&L - West County	7/30/2008	Combustion Turbines	2333 CT 428 DB	2.0 ppmvd @15% O_2, based	DLN and SCR

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
	Energy Center				on 24-hr average	
AZ-0047	Dome Valley Energy Partners - Wellton Mohawk Generating Facility	12/1/2004	Combustion Turbines	Unknown	2.0 ppmvd @15% O_2, based on 3-hr for 18 months and 1-hr average	DLN and SCR
WA-0315	Sumas Energy 2 Generation Facility	3/11/2004	*Combustion Turbines	334 MW per turbine	2.0 ppmvd @15% O_2, based on 3-hr average	DLN and SCR
ID-0012	Garnet Energy, Middleton Facility	10/19/2001	Combustion Turbines	1707 CT 390 DB	2.5 ppmvd @15% O_2, based on 12 month average	DLN and SCR
WA-0315	Wallula Power Plant	1/3/2003	Combustion Turbines	1300 MW	2.5 ppmvd @15% O_2, based on 3-hr average	SCR
GA-0102	Wansley Combined Cycle Energy Facility	1/15/2002	Combustion Turbines	167 MW	3 ppmvd @15% O_2	DLN and SCR
CA-1096	Vernon City Light and Power -	5/27/2003	Combustion Turbines	43 MW per turbine	2.0 ppmvd @15% O_2, based on 1-hr average	SCR

* Never constructed

The Sumas Energy 2 Generation Facility and Wallula Power Plant were never constructed and is not evaluated against the proposed project.

The proposed CCCTs will be subject to NSPS KKKK. NSPS KKKK provides a NO_X limit of 15 ppmvd at 15 percent O_2 for the CCCTs when burning natural gas. NSPS KKKK sets the floor of allowable NO_X BACT limits. The lowest BACT emission rate in all of the permits reviewed is 2 ppmvd at 15% O_2. No facilities identified in the permit search had a lower BACT emission rate. The entries vary in the determination of the most appropriate averaging period, ranging from a 1-hour average to a 30-day rolling average.

All of the facilities identified with the most stringent NO_X emission limits utilize SCR for control of NO_X emissions. Based on a review of the emission limits achievable and recent BACT determinations for similar facilities, the NO_X BACT for normal operation is a limit of 2 ppmvd at 15% O_2 on a 3-hour rolling average basis utilizing SCR. As shown in the above table, the proposed limit is consistent with the most stringent limit for NO_X at 2.0 ppmvd at 15% O_2.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for VOC emissions from the proposed combined cycle combustion turbines, identified as CCCT1 -CCCT4:

(1) The NOx emissions from the CCCT shall be controlled by a Selective Catalytic Reduction and DLN Burners.

(2) The NOx emissions shall not exceed 2.0ppmv @15% O_2 with duct burners based on a 3-hr average.

(3) The NOx emissions from each of the turbines and the associated burners, excluding startup and shutdown periods, shall not exceed 81.6 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for NOx for the combined cycle combustion turbines:

(1) The NOx emissions from the CCCTs shall be controlled by a Selective Catalytic Reduction and DLN Burners.

(2) The NOx emissions shall not exceed 2.0ppmv @15% O_2 with duct burners based on a 3-hr average.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT – Auxiliary Boilers B001- B002

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.

Step 2: Eliminate Technically Infeasible Options

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 and that cannot be economically accommodated. 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 Boilers (B001-B002) at this source.

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. Add-on control devices 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 electrostatic precipitator is not a technically feasible option for the Auxiliary Boilers (B001-B002) at this source.

Wet scrubbers:
A wet scrubber is an air pollution control device that removes PM 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 PM. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream. In general, collection efficiency decreases as the PM 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 PM 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. Another disadvantage is that they generate waste in the form of a sludge which requires treatment and/or disposal. 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. Add-on control devices 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 Boilers (B001-B002) at this source.

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. Add-on control devices 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 Boilers (B001-B002) at this source.

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, 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 Auxiliary Boilers (B001-B002) at this source.

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, 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 Boilers (B001-B002) at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of PM, PM_{10} and $PM_{2.5}$ resulting from the operation of the Auxiliary Boilers (B001-B002).

(1) Fuel Specifications

(2) Good Combustion Practices

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Auxiliary Boilers (B001 and B002)**	**80 MMBtu/hr**	**PM/PM10/PM2.5: 0.0075 lb/MMBtu and 0.6 lb/hr, each, based on 3-hr average**	**Good Combustion Practices and Fuel Specifications**
VA-0270	VCU EAST PLANT	3/31/2003	BOILER NATURAL GAS	150 MMBtu/hr	0.008 lb/MMBtu and 1.2 lb/hr	Good Combustion

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
						Practices
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	10/8/2009	AUXILIARY BOILER	150 MMBtu/hr	0.008 lb/MMBtu and 1.14 lb/hr	Unknown
NC-0101	FORSYTH ENERGY PLANT	9/29/2005	AUXILIARY BOILER	110.2 MMBtu/hr	0.074 lb/MMBtu and 0.82 lb/hr, based on 3-hr avg	GOOD COMBUSTION CONTROL AND NATURAL GAS ONLY
VA-0278	VCU EAST PLANT	3/31/2003	BOILER NATURAL GAS	150 MMBtu/hr	0.008 lb/MMBtu and 1.2 lb/hr	Unknown
OR-0046	TURNER ENERGY CENTER, LLC	1/6/2005	AUXILIARY BOILER	417,904 MMBtu/yr	none	Natural gas only
OR-0040	KLAMATH GENERATION, LLC	3/12/2003	*BOILER, AUXILIARY, NATURAL GAS	50,000 lb/hr	0.004 lb/MMBtu	Unknown
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	4/3/2002	Heaters (5)	50 MMBtu/hr	0.005 lb/MMBtu	Unknown
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	4/3/2002	Boiler No. 9	95 MMBtu/hr	0.0075 lb/MMBtu	Unknown
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	4/3/2002	Boiler No. 10	180 MMBtu/hr	0.0075 lb/MMBtu	Unknown
LA-0246	VALERO ST. CHARLES REFINERY	7/6/2011	EQT0323 - Boiler 401F	99 MMBtu/hr	0.74 lb/hr and 0.0075 lb/MMBtu	Proper design and operation, good combustion practices and gaseous fuels
OR-0048	PGE Carty Plant	12/24/2009	**NATURAL GAS-FIRED BOILER	91 MMBtu/hr	0.002 lb/MMBtu	Clean Fuel

Note: * Under construction
** Not yet constructed

The limits for the Williams Refining and Marketing, L.L.C. heaters are not applicable to this project, which includes installation of auxiliary boilers, not process heaters. The units for the Klamath Generation, LLC, and PGE Carty Plant have not yet been constructed, so these limits have not been demonstrated. Therefore, the proposed limit of 0.0075 lb/MMBtu is consistent with the most stringent limits for this type of operation.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ emissions from the proposed Auxiliary Boilers (B001-B002):

The PM, PM_{10} and $PM_{2.5}$ emissions from the Auxiliary Boilers, identified as B001-B002 shall be limited to less than 0.0075 lb/MMBtu and 0.6 lbs/hr, each, based on a 3-hr average period through the use of good combustion practices and fuel specification.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for the Auxiliary Boilers (B001-B002).

The PM, PM_{10} and $PM_{2.5}$ emissions from the Auxiliary Boilers, identified as B001-B002 shall not exceed 0.0075 lb/MMBtu and 0.6 lbs/hour, each, based on a 3-hr average period through the use of good combustion practices and fuel specification.

Carbon Monoxide (CO) BACT – Auxiliary Boilers B001 - B002

Step 1: Identify Potential 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) 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

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 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 Auxiliary Boilers at this source.

Recuperative Thermal Oxidizers
This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1.200^{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 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 Boilers at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, 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 Boilers at this source.

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 Boilers at this source

Good Combustion Controls
Good combustion controls is a continued operation of the CCCT at the appropriate oxygen range and temperature to promote complete combustion and minimize CO formation. Because CO is essentially a by-product of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of CO emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. CO emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics.

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 Boilers at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Oxidation Catalyst - (50-90% destruction efficiency)

(2) Combustion Control

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination along with the existing CO BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Auxiliary Boilers (B001 and B002)**	**80 MMBtu/hr**	**CO: 0.083 lb/MMBtu and 6.64 lb/hr,** each, **based on 3-hr average**	**Good Combustion Practices**
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	10/8/2009	AUXILIARY BOILER	150 MMBtu/h	12.6 lb/hr and 0.084 lb/MMBtu	None
NC-0101	FORSYTH ENERGY	9/29/2005	AUXILIARY BOILER	110.2 MMBtu/h	9.08 lb/hr and 0.082	LOW NO_X BURNERS &

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
	PLANT				lb/MMBtu, based on 3-hr avg	GOOD COMBUSTION CONTROL
WI-0204	UWGP - FUEL GRADE ETHANOL PLANT	8/14/2003	BOILER /OXIDIZER (DRYER / DISTILLATION), P10	140 MMBtu/h	18.4 lb/hr and 0.131 lb/MMBtu	None
LA-0184	TITANIUM DIOXIDE FACILITY	5/13/2003	UTILITY BOILERS D841-1X & D841-2X (135 MM BTU/H EA.)	135 MMBtu/h	12.229 lb/hr and 0.091 lb/MMBtu	GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION TECHNIQUES
VA-0270	VCU EAST PLANT	3/31/2003	BOILER NATURAL GAS	150 MMBtu/hr	0.099 lb/MMBtu and 14.9 lb/hr	GOOD COMBUSTION PRACTICE
VA-0278	VCU EAST PLANT	3/31/2003	BOILER NATURAL GAS (3)	150.6 MMBtu/hr	0.099 lb/MMBtu and 14.9 lb/hr	GOOD COMBUSTION PRACTICE
OR-0040	KLAMATH GENERATION, LLC	3/12/2003	*BOILER, AUXILIARY, NATURAL GAS	50,000 lb/hr	0.035 lb/MMBtu, based on 3-hr avg	Unknown
CO-0052	ROCKY MOUNTAIN ENERGY CENTER, LLC.	8/11/2002	NATURAL GAS FIRED BOILER (AUXILIARY BOILER)	129 MMBtu/hr	0.039 lb/MMBtu	GOOD COMBUSTION PRACTICES
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	4/3/2002	Boiler No. 9	95 MMBtu/hr	0.09 lb/MMBtu	Unknown
LA-0246	VALERO ST. CHARLES REFINDERY	7/6/2011	EQT0323 - Boiler 401F	99 MMBtu/Hr	0.092 lb/MMBtu and 9.15 lb/hr	Proper design and operation, good combustion practices and gaseous fuels

Note: *under construction.

The unit for Klamath Generation, LLC, has not yet been constructed, so this limit has not been demonstrated. The Rocky Mountain Energy Center, LLC value is an outlier and is specific to the design and operation of this facility. All other demonstrated limits for CO are not less than 0.082 lb/MMBtu. Therefore the proposed limit of 0.083 lb/MMBtu is consistent with all other limits in the RBLC for this type of operation.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for CO emissions from the proposed Auxiliary Boilers, identified as B001-B002:

The CO emissions from the Auxiliary Boilers (B001-B002) operation shall not exceed 0.083 lb/MMBtu and 6.64 lbs/hr, each, based on a 3 - hour average through Good Combustion Practices.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for CO for Auxiliary Boilers (B001-B002).

The CO emissions from the Auxiliary Boilers (B001-B002) operation shall not exceed 0.083 lb/MMBtu and 6.64 lbs/hr, each, based on a 3 - hour average through Good Combustion Practices.

Sulfur Dioxide (SO_2) BACT - Auxiliary Boilers B001 - B002

Step 1: Identify Potential Control Technologies

Sulfur Dioxide (SO_2) emissions result from the oxidation of fuel-bound sulfur, with emissions dependent upon the sulfur content of the fuel. Sulfur Dioxide (SO_2) 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. 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 netural salts.

FGD systems are not listed in the RBLC as BACT for the control of SO_2 emissions for auxiliary boilers. Technology has not been applied to natural gas auxiliary boiler due to very low SO_2 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 Boilers 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 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 SO_2 emissions for auxiliary boilers. Technology has not been applied to natural gas combustion turbines due to very low SO_2 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 Boilers 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 SO_2 emissions. Fuel Specifications is included in RBLC for the control of SO_2 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 Boilers at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The following measures have been identified for control of SO_2 resulting from the operation of the Auxiliary Boilers.

(1) Fuel Specifications

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed SO_2 BACT determination along with the existing SO_2 BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Auxiliary Boilers (B001 and B002)**	**80 MMBtu/hr**	**SO2: 0.0022 lb/MMBtu and 0.176 lb/hr,** each, **based on 3-hr average**	**Fuel Specifications**
VA-0270	VCU EAST PLANT	3/31/2003	BOILER NATURAL GAS	150 MMBtu/hr	0.299 lb/MMBtu	GOOD COMBUSTION PRACTICES.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
						LOW SULFUR FUELS.
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	8/17/2007	3 natural Gas-Fired Boilers	64.9 MMBtu/Hr, each	0.006 lb/MMBtu	None
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	8/17/2007	Boilers with ULNB	64.9 MMBtu/Hr, each	0.006 lb/MMBtu	None
IA-0062	EMERY GENERATING STATION	12/20/2002	Auxiliary Boilers	68 MMBtu/Hr, each	0.006 lb/MMBtu	Low Sulfur Fuel, Natural gas
OH-0251	CENTRAL SOYA COMPANY INC.	11/12/2007	Natural Gas Boiler	91.2 MMBtu/Hr, each	0.006 lb/MMBtu	None
AL-0231	NUCOR DECATUR LLC	6/12/2007	Vacuum Gegasser Boiler	95 MMBtu/Hr, each	0.006 lb/MMBtu	None
MN-0054	MANKATO ENERGY CENTER	12/4/2003	Auxiliary Boilers	70 MMBtu/Hr	0.001 lb/MMBtu	Low Sulfur Fuel
VA-0255	VA POWER - POSSUM POINT	11/18/2002	Auxiliary Boilers	99 MMBtu/Hr	0.001 lb/MMBtu	Low Sulfur Fuel and Good Combustion Practices
NV-0047	NELLIS AIR FORCE BASE	2/26/2008	Boiler/Heater	Unknown	0.0015 lb/MMBtu	Use of Pipeline-Quality natural gas
AZ-0049	LA PAZ GENERATING FACILITY	9/4/2003	Auxiliary Boilers	55.34 MMBtu/Hr	0.0025 lb/MMBtu	None
LA-0174	PORT HUDSON OPERATIONS	1/25/2002	Power Boilers No.2	65.5 MMBtu/Hr	0.004 lb/MMBtu	Firing Natural Gas
IN-0085	PSEG LAWRENCEBURG ENERGY FACILITY	6/7/2001	Auxiliary Boilers	124.6 MMBtu/Hr	0.006 lb/MMBtu	Low Sulfur Natural gas 9less than 0.8% by weight)
OH-0257	JACKSON COUNTY POWER, LLC	12/27/2001	Auxiliary Boilers	76 MMBtu/Hr	0.006 lb/MMBtu	LOW SULFUR FUEL, NATURAL GAS SULFUR LIMIT - 2 GR/100 SCF

The Mankato Energy Center - according to page 9 of 12 in the TSD to the Title V permit for this facility, the Permittee reported a manufacturer's SO2 emissions rate of 0.0012 lb/MMBtu for natural gas but this doesn't coincide with the 0.8 gr S/100scf, so the 0.0022409 lb/MMBtu value was used in place of 0.012 lb/MMBtu. (http://www.pca.state.mn.us/index.php/view-document.html?gid=1402). The Nellis Air Force Base SO2 limit is for 125 regulated and 142 exempt units, including boilers and other heaters, at this facility. Therefore, this limit it is not comparable to the auxiliary boiler proposed for SJEC. The VA Power - Possum Point, according to the Title V permit for this facility, has an approved fuel for the auxiliary boiler is guaranteed at 0.3 gr S/100 dscf. The natural gas supplier for SJEC cannot provide a sulfur content guarantee at this level. IDEM is aware that some vendors have guaranteed emission factors to control similar processes for other proposed auxiliary boilers. However, BACT limitations do not necessarily need to reflect the highest possible emission factors achievable by the technology on which the emission limitation is based. The permitting authority has discretion to base the emission limitation on an emission factor that is somewhat lower than the optimal level, which can be achieved by the emission unit consistently.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for SO_2 emissions from the proposed Auxiliary Boilers, identified as B001-B002:

The SO_2 emissions from the Auxiliary Boilers, identified as B001-B002 shall not exceed 0.0022 lb/MMBtu and 0.176 lbs/hr, each, based on a 3-hr average through the use of fuel specification.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for SO_2 for the Auxiliary Boilers, identified as B001-B002.

The SO_2 emissions from the Auxiliary Boilers, identified as B001-B002 shall not exceed 0.0022 lb/MMBtu and 0.176 lbs/hr, each, based on a 3-hr average through the use of fuel specification.

Volatile Organic Compounds (VOCs) BACT - Auxiliary Boilers B001 - B002

Step 1: Identify Potential Control Technologies

Emissions of Volatile Organic Compounds (VOCs) are generally controlled by oxidation. Oxidation technologies include regenerative thermal oxidation, catalytic oxidation, and flares.

(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

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 VOCs emissions. Upon passing through the flame, the waste gas containing VOCs is heated. The mixture continues to react as it flows through the combustion chamber.

The required level of VOCs destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of 1,200 to 2,000^{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.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a regenerative thermal oxidizer is a technically feasible option for the Auxiliary Boilers at this source.

Recuperative Thermal Oxidizers
This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1.200^{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 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 Boilers at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling VOCs 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 Boilers at this source.

Flare
Although the VOC concentration is very low, the stream flow rate is very high. The low heating value of the stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NO_x. Flares have not been utilized or demonstrated as a control device for VOCs from this type of high-volume process stream. In addition, the flare would have no additional control versus the thermal oxidizers.

Based on 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 Boilers at this source

Good Combustion Controls
Good combustion controls is a continued operation of the Boilers at the appropriate oxygen range and temperature to promote complete combustion and minimize VOC formation. Because VOC is essentially a by-product of incomplete or inefficient combustion, combustion control constitutes the primary mode of reduction of VOC emissions. This type of control is appropriate for any type of fuel combustion source. Combustion process controls involve combustion chamber designs and operating practices that improve the oxidation process and minimize incomplete combustion. VOC emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting VOC emissions include firing temperatures, residence time in the combustion zone and combustion chamber mixing characteristics.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good Combustion Controls is a technically feasible option for the Auxiliary Boilers at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Oxidation Catalyst - (20-40% destruction efficiency)

(2) Good Combustion Controls

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOCs BACT determination along with the existing VOCs BACT determinations for similar plants. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Auxiliary Boilers (B001 and B002)**	**80 MMBtu/hr**	**VOCs: 0.005 lb/MMBtu and 0.4 lb/hr, each, based on 3-hr average**	**Good Combustion Practices**
NC-0101	FORSYTH ENERGY PLANT	9/29/2005	AUXILIARY BOILER	110.2 MMBtu/hr	0.59 lb/hr and 0.005 MMBtu/hr, based on 3-hr avg	LOW NO_X BURNERS, GOOD COMBUSTION CONTROL AND NATURAL GAS ONLY
OR-0046	TURNER ENERGY CENTER, LLC	1/6/2005	Auxiliary Boilers	417,904 MMBtu/yr	0.0044 lb/MMBtu based on 3-hr block	Oxidation Catalyst
VA-0270	VCU EAST PLANT	3/31/2003	BOILER NATURAL GAS	150 MMBtu/hr	2.1 lb/hr and 0.014 MMBtu/hr	GOOD COMBUSTION PRACTICES.
VA-0270	VCU EAST PLANT	3/31/2003	BOILER NATURAL GAS	150.6 MMBtu/hr	2.1 lb/hr and 0.014 MMBtu/hr	GOOD COMBUSTION PRACTICES.
LA-0246	VALERO ST. CHARLES REFINDERY	7/6/2011	EQT0323 - Boiler 401F	99 MMBtu/hr	0.53 lb/hr and 0.005 MMBtu/hr	Proper design and operation, good combustion practices and gaseous fuels
IN-0085	PSEG LAWRENCEBURG ENERGY FACILITY	6/7/2001	Auxiliary Boilers	124.6 MMBtu/hr	0.0054 lb/MMBtu	Good Combustion Practices and Natural Gas only

The use of oxidation catalyst is economically infeasible as referenced in the cost analysis. The emission limits in Turner Energy Center, LLC which is 0.0044 lb/MMBtu has never been tested because the facility was never constructed and this was confirmed by the Oregon DEQ. Therefore, the proposed limit of 0.005 lb/MMBtu is consistent with the most stringent limits for this type of operation.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ emissions from the proposed Auxiliary Boilers (B001-B002):

The VOC emissions from the Auxiliary Boilers, identified as B001-B002 shall not exceed 0.005 lb/MMBtu and 0.4 lbs/hr, each, based on a 3-hr average period through the use of good combustion practices.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for VOC for the Auxiliary Boilers (B001-B002).

The VOC emissions from the Auxiliary Boilers, identified as B001-B002 shall not exceed 0.005 lb/MMBtu and 0.4 lbs/hr, each, based on a 3-hr average period through the use of good combustion practices.

Nitrogen Oxide (NOx) BACT - Auxiliary Boilers B001 - B002

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)

Add-on control technologies and combustion control approaches are discussed below.

Step 2: Eliminate Technically Infeasible Options

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 sootblower.

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 Boilers at this source.

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 Boilers at this source.

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 includes 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 is 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 Boilers at this source.

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 Boilers 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)

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 permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Auxiliary Boilers (B001 and B002)**	**80 MMBtu/hr**	**NOx: 0.032 lb/MMBtu and 2.56 pounds per hour, each, based on 3-hr average**	**Low NOx Burner with Flue Gas Recirculation**
VA-0270	VCU EAST PLANT	3/31/2003	BOILER NATURAL GAS	150 MMBtu/hr	0.1 lb/MMBtu	GOOD COMBUSTION PRACTICES. LOW NO_X COMBUSTION AND FGR. CEM SYSTEM.
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	10/8/2009	AUXILIARY BOILER	150 MMBtu/hr	0.14 lb/MMBtu and 21 lb/hr	UNKNOWN
OK-0126	SUNOCO INC TULSA REFINERY	5/27/2008	Process Heater	53.7 MMBtu/hr	0.03 lb/MMBtu	Ultra Low NOx Burner
CA-1148	CELITE	6/11/2007	HEATER-OTHER PROCESS	50 MMBtu/hr	0.089 lb/MMBtu	Ultra Low NOx Burner
NC-0101	FORSYTH ENERGY PLANT	9/29/2005	AUXILIARY BOILER	110.2 MMBtu/hr	0.137 lb/MMBtu and 15.13 lb/hr, based on 3-hr avg	LOW NO_X BURNERS, GOOD COMBUSTION CONTROL
OR-0046	TURNER ENERGY CENTER, LLC	1/6/2005	AUXILIARY BOILER	417,904 MMBtu/yr	0.011 lb/MMBtu, based on 3-hr block	SELECTIVE CATALYTIC REDUCTION
ID-0015	J R SIMPLOT COMPANY - DON SIDING PLANT	4/5/2004	BOILER, 64 MMBTU/H	110.2 MMBtu/hr	0.045 lb/MMBtu and 2.88 lb/hr	Low NOx Burner
LA-0183	TITANIUM DIOXIDE FACILITY	11/14/2003	BOILERS, UTILITY, D841-1X & D841-2X	135 MMBtu/hr	0.074 lb/MMBtu and 10 lb/hr	Low NOx Burner
WI-0204	UWGP - FUEL GRADE ETHANOL	8/14/2003	BOILER /OXIDIZER (DRYER / DISTILLATION), P10	140 MMBtu/hr	0.095 lb/MMBtu and	BOILER / BURNER DESIGN

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
	PLANT				10 lb/hr	
VA-0270	VCU EAST PLANT	3/31/2003	BOILER NATURAL GAS (3)	150.6 MMBtu/hr	15.6 lb/hr and 0.104 MMBtu/hr	LOW NO_X BURNERS, FGR, AND GOOD OPERATING PROCEDURES
CO-0052	ROCKY MOUNTAIN ENERGY CENTER, LLC.	8/11/2002	NATURAL GAS FIRED BOILER (AUXILIARY BOILER)	129 MMBtu/hr	0.038 MMBtu/hr	OPERATION IS LIMITED TO 1,900 H/YR. LOW NO_X COMBUSTION SYSTEM.
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	4/3/2002	Heaters (5)	50 MMBtu/hr	0.03 lb/MMBtu	None
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	4/3/2002	Boiler No.9	95 MMBtu/hr	0.084 lb/MMBtu	None
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	4/3/2002	CCR STABILIZATION REBOILER	54 MMBtu/hr	0.06 lb/MMBtu	None
LA-0246	VALERO ST. CHARLES REFINDERY	7/6/2011	EQT0323 - Boiler 401F	99 MMBtu/hr	0.084 lb/MMBtu	Ultra LNB and/or CSR
OR-0048	PGE Carty Plant	12/24/2009	NATURAL GAS-FIRED BOILER	91 MMBtu/hr	0.04 lb/MMBtu	LOW NO_X BURNERS
IN-0085	PSEG LAWRENCEBURG ENERGY FACILITY	6/7/2001	*Auxiliary Boiler	124.6 MMBtu/hr	4.5 lb/hr and 0.049 lb/MMBtu	Low NOx Burners, Natural Gas Only

Note: * Not yet constructed.

The use of oxidation catalyst is economically infeasible as referenced in the cost analysis. The emission units at Turner Energy Center, LLC which are limited to 0.011 lb/MMBtu have never been tested because the facility was never constructed and this was confirmed by the Oregon DEQ. The limits for the Williams Refining and Marketing, L.L.C. and Sunoco Inc Tulsa Refinery process heaters are not applicable to this project, which includes installation of auxiliary boilers, not process heaters. Therefore, the proposed limit of 0.032 lb/MMBtu is consistent with the most stringent limits for this type of operation.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for VOC emissions from the proposed Auxiliary Boilers, identified as B001-B002:

(1) The NOx emissions from the Auxiliary Boilers, identified as B001-B002 shall be controlled by a Low NOx Burner with Flue Gas Recirculation.

(2) The NOx emissions shall be limited to less than 0.032 lb/MMBtu based on a 3-hr average period.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for NOx for the Auxiliary Boilers, identified as B001-B002:

(1) The NOx emissions from the Auxiliary Boilers, identified as B001-B002 shall be controlled by Low NOx Burners with Flue Gas Recirculation.

(2) The NOx emissions shall not exceed 0.032 lb/MMBtu and 2.56 pounds per hour, each, based on a 3-hr average period.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT – Firewater Pumps

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) Catalyzed Diesel Particulate Filter (CDPF);

(2) Good Combustion Practices; and

(3) Usage Limitation.

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

Catalyzed Diesel Particulate Filter (CDPF)
The particulate matter emissions in exhaust gas is trapped by a ceramic filter and oxidized using a metallic catalyst or a base. The operating temperature ranges between 480 - 570°F. The exhaust gas temperature must be high enough over an extended period of time to allow for filter regeneration. The type of control is not included in RBLC for the control of PM emissions from fire pump and emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Catalyzed Diesel Particulate Filter is not an economically feasible option for the Firewater Pump Engine at this source.

Good Combustion Practices
The 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 pyrolize 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. This type of emission control is included in RBLC for the control of particulate emissions from fire pump and emergency engines.

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 Firewater Pump Engine at this source.

Usage Limitation
Usage limitation involves accepting a limit on the maximum hours of operation on the units, which results in lower emissions. This is included in RBLC for the control of particulate emissions from fire pump and emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Usage Limitation is a technically feasible option for the Firewater Pump Engine at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

1. Good Combustion Practices.

2. Usage Limitation.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control and usage limitation shall be used to reduce the particulate emissions from the fire pump engines at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for emergency engines. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Firewater Pump Engines**	**371 brake horsepower**	**PM, PM_{10} and $PM_{2.5}$: 0.15 g/bhp-hr**	**Combustion Design Controls and Usage Limits**
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009	Fire Pump	525 HP	0.15 g/hp-hr	Engine Design and Operation. 15 ppm Sulfur Fuel
MI-0390	KARN WEADOCK GENERATING COMPLEX	12/29/2009	Emergency Generator	2000 KW	0.2 g/hp-hr	Engine Design and Operation. 15 ppm Sulfur Fuel
MI-0393	KARN WEADOCK GENERATING COMPLEX	12/29/2009	Fire Booster Pump	40 KW	0.4 G/KW-H	Engine Design and Operation. 15 ppm Sulfur Fuel
MI-0395	KARN WEADOCK GENERATING COMPLEX	12/29/2009	Fire Pump	305 KW	0.2 g/hp-hr	Engine Design and Operation. 15 ppm Sulfur Fuel

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
ID-0018	LANGLEY GULCH POWER PLANT	6/25/2010	Emergency Generator Engine	750 KW	0.2 G/KW-H	Tier 2 Engine-Based on Good Combustion Practices
ID-0018	LANGLEY GULCH POWER PLANT	6/25/2010	Fire Pump Engine	235 KW	0.2 G/KW-H	Tier 2 Engine-Based on Good Combustion Practices
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	12/23/2010	Emergency Generators	2682 HP	0.2 G/KW-H	None
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	12/23/2010	Emergency Generators	600 HP	0.15 g/hp-hr	None
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	12/23/2010	Emergency Generators	250 KW	0.2 G/KW-H	Use inherently clean ultra low sulfur distillate (ULSD) fuel oil and GCP & demonstrate Compliance in accordance with the procedure given in 40 CFR 60, Subpart IIII
FL-0324	PALM BEACH RENEWABLE ENERGY PARK	12/23/2010	Emergency diesel Firewater Pump engines	250 HP	0.15 g/hp-hr	Demonstrate Compliance in accordance with the procedure given in 40 CFR 60, Subpart IIII

As shown in the above table, a proposed limit of 0.15 g/bhp-hr, which is equivalent to 0.20 g/kW-hr, is consistent with the most stringent limits contained in the RBLC.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Fire Pump Engines:

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Firewater Pump Engines shall not exceed 0.15 g/hp-hr through the use of combustion design control and usage limitation.

(2) The Fire Pumps shall not exceed 500 hours per year of, each.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for the Fire Pump Engines.

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Firewater Pump Engines shall not exceed 0.15 g/hp-hr through the use of combustion design control and usage limitation.

(2) The Fire Pump shall not exceed 500 hours per year, each.

Carbon Monoxide (CO) BACT – Firewater Pumps

Step 1: Identify Potential Control Technologies

Emissions of carbon monoxide (CO) are generally controlled by oxidation. Oxidation technologies include:

(a) Regenerative thermal oxidation;

(b) Recuperative thermal oxidation;

(c) Catalytic oxidation;

(d) Combustion Design Controls; and

(e) Flares

(f) Usage Limitations

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, 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.

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.

This control is not included in RBLC for the control of CO emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

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 Firewater Pump Engines at this source.

Recuperative Thermal Oxidizers
This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1.200^{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.

This control is not included in RBLC for the control of CO emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

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 Firewater Pump Engines at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, 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 not included in RBLC for the control of CO emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is not a technically feasible option for Firewater Pump Engines at this source.

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 Firewater Pump Engines at this source.

Combustion Design Controls
CO emissions are caused through incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form where fuel will partially combust, resulting in 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. This type of control is included in RBLC for the control of CO emissions from fire pump & emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Good Combustion Controls is a technically feasible option for the Firewater Pump Engines at this source.

Usage Limitation
Usage limitation involves accepting a limit on the maximum hours of operation on the units, which results in lower emissions. This is included in RBLC for the control of CO emissions from fire pump and emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Usage Limitation is a technically feasible option for the Firewater Pump Engine at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control and usage limitation shall be used to reduce the CO emissions from the firewater pump engines at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination along with the existing CO BACT determinations for emergency engines. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579	**St. Joseph Energy Center - *proposed***	**Proposed**	**Firewater Pump Engines**	**371 brake horsepower**	**CO: 2.6 g/bhp-hr**	**Combustion Design Controls and Usage Limits**

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Proposed Limit						
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009	Fire Pump	525 HP	2.6 g/hp-hr	Engine design and Operation. 15 ppm Sulfur fuel
MI-0390	KARN WEADOCK GENERATING COMPLEX	12/29/2009	Emergency Generators	2000 KW	3.5 G/KW-H	Engine design and Operation. 15 ppm Sulfur fuel
MI-0391	KARN WEADOCK GENERATING COMPLEX	12/29/2009	Fire Booster Pump	40 KW	5 G/KW-H	Engine design and Operation. 15 ppm Sulfur fuel
MI-0392	KARN WEADOCK GENERATING COMPLEX	12/29/2009	Flue gas Desulfurization Quench Pump	305 KW	3.5 G/KW-H	Engine design and Operation. 15 ppm Sulfur fuel
NV-0049	HARRAH'S OPERATING COMPANY, INC.	8/20/2009	Large Internal Combustion Engines	1,232 HP	0.006 lb/HP-H	The unit is equipped with a Turborcharger
NV-0050	HARRAH'S OPERATING COMPANY, INC.	8/20/2009	Small Internal Combustion Engines	536 HP	0.007 lb/HP-H	The unit is equipped with a Turborcharger
NV-0052	MGM MIRAGE	11/30/2009	Small Internal Combustion Engines	350 HP	0.007 lb/HP-H	Turborcharger and Good Combustion Practices
LA-0229	SHINTECH PLAQUEMINE PLANT 2	7/10/2008	Emergency IC Engines	< 600 HP	0.007 lb/HP-H	Follow Manufacture's Specifications

As shown in the above table, a proposed limit of 2.6 g/bhp-hr, which is equivalent to 3.5 g/kW-hr and 0.006 lb/bhp-hr, is consistent with the most stringent limits contained in the RBLC.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for CO emissions from the proposed Fire Pump Engines:

(1) The CO emissions from the Firewater Pump Engines shall not exceed 2.6 g/hp-hr through the use of combustion design controls and usage limitation.

(2) The Fire Pumps shall not exceed 500 hours per year, each.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for CO emissions for the Fire Pump Engines.

(1) The CO emissions from the Firewater Pump Engines shall not exceed 2.6 g/hp-hr through the use of combustion design control and usage limitation.

(2) The Fire Pumps shall not exceed 500 hours per year of, each.

Sulfur Dioxide (SO_2) BACT - Firewater Pumps

Step 1: Identify Potential Control Technologies

Sulfur Dioxide (SO_2) emissions result from the oxidation of fuel-bound sulfur, with emissions dependent upon the sulfur content of the fuel. Sulfur Dioxide (SO_2) emissions are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

(a) Fuel Specification; and

(b) Good Combustion Practices.

(c) Usage Limitation.

Add-on control measures are generally based upon exposure of sulfur dioxide molecules to reagents that react with sulfur dioxide to form a sulfate molecule that can then be captured as a particulate. Sulfur dioxide control systems vary in reagent utilized to react with sulfur dioxide, the manner in which the reagent is exposed to sulfur dioxide, and the manner in which sulfate molecules are captured.

Step 2: Eliminate Technically Infeasible Options

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 SO_2 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 Firewater pumps at this source.

Good Combustion Practices
Good combustion practices as well as operation and maintenance of the fire pumps to keep them in good working order per the manufacturer's specifications will minimize SO_2 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 Firewater Pumps at this source.

Usage Limitation
Usage limitation involves accepting a limit on the maximum hours of operation on the units, which results in lower emissions. This is included in RBLC for the control of SO_2 emissions from fire pump and emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Usage Limitation is a technically feasible option for the Firewater Pump Engine at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of ultra low sulfur distillate (ULSD) (Fuel Specification and Good combustion practices) and usage limitation shall be used to reduce the SO_2 emissions from the firewater pump engines at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed SO_2 BACT determination along with the existing SO_2 BACT determinations for emergency pumps. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Firewater Pump Engines**	**371 brake horsepower**	**SO_2: 0.0015% sulfur diesel fuel and 0.043 lbs/hr**	**ULSD and Usage Limits**
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	12/28/2004	Fire Water Pump	265 HP	0.1 lb/hr	Low Sulfur Fuel
OK-0129	CHOUTEAU POWER PLANT	1/23/2009	Emergency Fire Pump	267 HP	0.11 lb/hr	Low Sulfur Fuel
OH-0281	RUMPKE SANITARY LANDFILL, INC	6/10/2004	Portable Engines	0.58 MMBtu/hr	0.17 lb/hr	None
LA-0122	MANSFIELD MILL	8/14/2001	Diesel Generator	130 HP	0.26 lb/hr	Preventive Maintenance
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	12/28/2004	Backup Generators	500 KW	0.27 lb/hr	Low Sulfur Fuel
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	3/21/2003	Backup Generators, Diesel	749 BHP	0.3 lb/hr (<0.05% S by wt)	Use of low sulfur diesel fuel
LA-0122	MANSFIELD MILL	8/14/2001	Diesel Engines	152 HP	0.31 lb/hr	Preventive Maintenance
WI-0227	PORT WASHINGTON GENERATING STATION	10/13/2004	Diesel Engines Generator	0.58 MMBtu/hr	0.38 lb/hr (0.05% wt S)	Low sulfur diesel fuel
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	8/14/2003	Emergency diesel-fired generator	600 KW	0.4 lb/hr	Low sulfur fuel combustion control
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	3/21/2003	Fire Water Pump	265 BHP	0.5 lb/hr (<0.05% S by wt)	Use of very low sulfur diesel fuel

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
WI-0228	WPS - WESTON PLANT	10/19/2004	Diesel Booster Pump	265 BHP	0.54 lb/hr (0.003 WT %)	Fuel Sulfur Content Limit Good Combustion practices

SO_2 emissions depend entirely on the sulfur content of the fuel. Use of ultra-low sulfur diesel fuel (< 0.0015% S) is the most stringent limit for fuel sulfur content in the RBLC.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for SO_2 emissions from the proposed Firewater Pump Engines:

(1) The SO_2 emissions from the Firewater Pump Engines shall not exceed 0.0015 % S and 0.043 lb/hr through the use of ultra low sulfur distillate (ULSD) and usage limitation.

(2) The Fire Pumps shall not exceed 500 hours per year, each.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for SO_2 emissions for the Fire Pump Engines.

(1) The SO_2 emissions from the Firewater Pump Engines shall not exceed 0.0015 % S and 0.043 lb/hr, each through the use of ultra low sulfur distillate (ULSD) and usage limitation.

(2) The Fire Pumps shall not exceed 500 hours per year, each.

Volatile Organic Compounds (VOCs) BACT - Firewater Pumps

Step 1: Identify Potential Control Technologies

Emissions of volatile organic compounds (VOC) are generally controlled by oxidation. Oxidation technologies include:

(a) Regenerative thermal oxidation;

(b) Recuperative thermal oxidation;

(c) Catalytic oxidation;

(d) Combustion Design Controls; and

(e) Flares.

(f) Usage Limitation

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, 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 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.

This control is not included in RBLC for the control of VOC emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

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 Firewater Pump Engines at this source.

Recuperative Thermal Oxidizers
This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1.200^{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 VOC from properly operated natural gas combustion units without the use of a catalyst.

This control is not included in RBLC for the control of VOC emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

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 Firewater Pump Engines at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling VOC emissions. A catalyst is an

element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without 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 not included in RBLC for the control of VOC emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is not a technically feasible option for Firewater Pump Engines at this source.

Flare
Although the VOC concentration is very low, the stream flow rate is very high. The low heating value of the stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NOx. Flares have not been utilized or demonstrated as a control device for 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 Firewater Pump Engines at this source.

Combustion Design Controls
VOC emissions are caused through incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form where fuel will partially combust, resulting in VOC and unburned hydrocarbons that exit with the exhaust. VOC 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. This type of control is included in RBLC for the control of VOC emissions from fire pump & emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Good Combustion Controls is a technically feasible option for the Firewater Pump Engines at this source.

Usage Limitation
Usage limitation involves accepting a limit on the maximum hours of operation on the units, which results in lower emissions. This is included in RBLC for the control of VOC emissions from fire pump and emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Usage Limitation is a technically feasible option for the Firewater Pump Engine at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control and usage limitation shall be used to reduce the VOC emissions from the firewater pump engines at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination along with the existing VOC BACT determinations for emergency engines. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	**Facility**	**Issued Date**	**Process Description**	**Rating (TPH)**	**Limitation**	**Control Method**
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Firewater Pump Engines**	**371 brake horsepower**	**VOC: 0.16 lbs/hr**	**Combustion Design Controls and Usage Limits**
LA-0194	SABINE PASS LNG TERMINAL	11/24/2004	Fire Water Pump Diesel Engines	660 HP	0.07 lb/hr	Good Combustion Practices
LA-0195	SABINE PASS LNG TERMINAL	11/24/2004	Standby Generator Diesel Engines	2,220 HP	Unknown	Complying with 40 CFR 60 Subpart IIII
LA-0196	SABINE PASS LNG TERMINAL	11/24/2004	Fire Water Booster Pump Diesel Engines	300 HP	0.1 lb/hr	Good Engine Design & Proper operating Practices
NC-0101	FORSYTH ENERGY PLANT	9/29/2005	IC Engine, Emergency Generators	11.4 MMBtu/hr	1.04 lb/hr	None
NJ-0043	LIBERTY GENERATING STATION	3/28/2002	Emergency Generators	14.1 MMBtu/hr	1.4 lb/hr	None
NJ-0044	LIBERTY GENERATING STATION	3/29/2002	Diesel Fire Pump	3.5 MMBtu/hr	1.2 lb/hr	None
WI-0228	WPS - WESTON PLANT	10/19/2004	Diesel Booster Pump	265 HP	0.7 lb/hr	Combustion practices, ultra low Sulfur (0.003 WT %) Diesel Fuel Oil
WI-0229	WPS - WESTON PLANT	10/19/2004	Main Fire Pump (Diesel Engine)	460 HP	1.14 lb/hr	Combustion Practices, ultra low Sulfur (0.003 WT %) Diesel Fuel Oil
WV-0023	MAIDSVILLE	3/2/2004	Emergency Generators	1,801 HP	1.12 lb/hr	Good Combustion Practices
WV-0023	MAIDSVILLE	3/2/2004	IC Engines, Fire Water Pump	85 HP	0.64 lb/hr	Good Combustion Practices

The Sabine Pass LNG Terminal Firewater Pump Diesel Engines have NOx emissions equivalent to 8.4 g/hp-hr, which are higher than the Tier 3 emissions standards of 3.0 g/hp-hr and therefore cannot be used at the proposed facility. As shown in the above table, a proposed limit of 0.16 lb/hr is consistent with the other limits contained in the RBLC.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for VOC emissions from the proposed Firewater Pump Engines:

(1) The VOC emissions from the Firewater Pump Engines shall not exceed 0.16 lb/hr through the use of Combustion Design Controls and usage limitation.

(2) The Fire Pumps shall not exceed 500 hours per year, each.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for VOC emissions for the Fire Pump Engines.

(1) The VOC emissions from the Firewater Pump Engines shall not exceed 0.16 pounds per hour, each through the use of Combustion Design Controls and usage limitation.

(2) The Fire Pumps shall not exceed 500 hours per year, each.

Nitrogen Oxide (NOx) BACT - Firewater Pumps

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) Combustion Design Controls

(d) Usage Limitations

Add-on control technologies and combustion control approaches are discussed below.

Step 2: Eliminate Technically Infeasible Options

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 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 sootblower.

This control is not included in RBLC for the control of NOx emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective catalytic reduction (SCR) is not a technically feasible option for the Firewater Pump Engines at this source.

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 NOx 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.

This control is not included in RBLC for the control of NOx emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective non-catalytic reduction (SNCR) is not a technically feasible option for the Firewater Pump Engines at this source.

Combustion Design Controls
NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. These effects can be minimized through air-to-fuel ratio control, ignition timing reduction, and exhaust gas recirculation. This type of control is included in RBLC for the control of NO_X emissions from fire pump & emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Good Combustion Controls is a technically feasible option for the Firewater Pump Engines at this source.

Usage Limitation
Usage limitation involves accepting a limit on the maximum hours of operation on the units, which results in lower emissions. This is included in RBLC for the control of NOx emissions from fire pump and emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Usage Limitation is a technically feasible option for the Firewater Pump Engine at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

1. Good Combustion Controls.

2. Usage Limitation.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control and usage limitation shall be used to reduce the NOx emissions from the firewater pump engines at this source.

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 emergency pumps. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Firewater Pump Engines**	**371 brake horsepower**	**NOx + NMNC: 3.0 g/bhp-hr**	**Combustion Design Controls and Usage Limits**
FL-0322	SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY	12/23/2010	Emergency Diesel Fire Pump	600 HP	3 g/hp-hr	None
LA-0194	SABINE PASS LNG TERMINAL	11/24/2004	Firewater Pump Diesel	660 HP	12.2 lb/hr (8.4 g/hp-hr)	Good Engine Design and Proper operating Practices
LA-0195	SABINE PASS LNG TERMINAL	11/24/2004	Standby Generator Diesel Engines	2,220 HP	None	Complying with 40 CFR 60 Subpart IIII
LA-0196	SABINE PASS LNG TERMINAL	11/24/2004	Firewater Booster Pump Diesel Engines	300 HP	3.44 lb/hr (5.2 g/hp-hr)	Good Engine Design and Proper operating Practices
NV-0049	HARRAH'S OPERATING	8/20/2009	Large Internal combustion	1,232 HP	0.024 lb/hp-hr	The unit is equipped with a

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
	COMPANY, INC.		Engines			Turborcharger
NV-0050	MGM MIRAGE	11/30/2009	Emergency Generators	2,206 HP	0.0131 lb/hb-hr	Turborcharger After Cooling and lean Burn Technology
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	2/10/2009	Emergency Generators	2000 KW	None	Good Combustion Practices. EPA Certification Per NSPS IIII
ID-0018	POWER COUNTY ADVANCED ENERGY CENTER	2/10/2009	Emergency Generators	500 KW	None	Good Combustion Practices. EPA Certification Per NSPS IIII
NJ-0043	LIBERTY GENERATING STATION	3/28/2002	Emergency Generators	14.4 MMBtu/hr	26.2 lb/hr (5.9 g/hp-hr)	None
NJ-0044	LIBERTY GENERATING STATION	3/29/2002	Diesel Fire Pump	3.5 MMBtu/hr	15.5 lb/hr (14 g/hp-hr)	None

As shown in the above table, a proposed limit of 3.0 g/bhp-hr, which is equivalent to 0.0066 lb/hp-hr, is consistent with the most stringent limits contained in the RBLC.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for NOx emissions from the proposed Fire Pump Engines:

(1) The NOx emissions from the Firewater Pump Engines shall not exceed 3.0 g/bhp-hr for NOx + NMHC through the use of Combustion Design Controls and usage limitation.

(2) The Fire Pumps shall not exceed 500 hours per year of non-emergency operation, each.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for NOx emissions for the Fire Pump Engines.

(1) The NOx emissions from the Firewater Pump Engines shall not exceed 3.0 g/bhp-hr for NOx + NMHC through the use of Combustion Design Controls and usage limitation.

(2) The Fire Pumps shall not exceed 500 hours per year, each.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT –Emergency Diesel Generators

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) Catalyzed Diesel Particulate Filter (CDPF);

(2) Good Combustion Practices; and

(3) Usage Limitation.

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

Catalyzed Diesel Particulate Filter (CDPF)
The particulate matter emissions in exhaust gas is trapped by a ceramic filter and oxidized using a metallic catalyst or a base. The operating temperature ranges between 480 - 570°F. The exhaust gas temperature must be high enough over an extended period of time to allow for filter regeneration. The type of control is not included in RBLC for the control of PM emissions from fire pump and emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Catalyzed Diesel Particulate Filter is not an economically feasible option for the Emergency Diesel Generators at this source.

Good Combustion Practices
The 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 pyrolize 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. This type of emission control is included in RBLC for the control of particulate emissions from fire pump and emergency engines.

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 Emergency Diesel Generators at this source.

Usage Limitation
Usage limitation involves accepting a limit on the maximum hours of operation on the units, which results in lower emissions. This is included in RBLC for the control of particulate emissions from firewater pump and emergency diesel engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Usage Limitation is a technically feasible option for the Emergency Diesel Generators at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control and usage limitation shall be used to reduce the particulate emissions from the Emergency Diesel Generators at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for emergency engines. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Emergency Diesel Generators EG01 & EG02**	**1,006 horsepower, each**	**PM, PM_{10} and $PM_{2.5}$: 0.15 g/bhp-hr**	**Combustion Design Controls and Usage Limits**
			Emergency Generator EG03	**2,012 horsepower**		
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009	Emergency Generator	2000 KW	0.2 G/KW-H	Engine Design and Operation. 15 ppm Sulfur Fuel
ID-0018	LANGLEY GULCH POWER PLANT	6/25/2010	Emergency Generator Engine	750 KW	0.2 G/KW-H	Tier 2 Engine-Based on Good Combustion Practices
FL-0310	SHADY HILLS GENERATING STATION	1/12/2009	Emergency generators	2.5 MW	0.4 g/hp-hr	Firing ULSO with max. Sulfur content of 0.0015% by WT and Max. Hours of operation of 500 hour/yr
MN-0054	MANKATO ENERGY CENTER	12/4/2003	Large IC	1850 HP	0.07 g/b-hp-hr	Good Combustion
MN-0054	MANKATO ENERGY CENTER	12/4/2003	Small IC	290 HP	0.07 g/b-hp-hr	Good Combustion
MN-0071	FAIRBAULT ENERGY PARK	6/5/2007	Emergency Generator	1750 KW	0.0004 lb/hp-hr	None
MN-0071	FAIRBAULT ENERGY PARK	6/5/2007	Emergency Generator	1750 KW	0.0007 lb/hp-hr	None
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	8/14/2003	Emergency diesel fired engines Generator	600 KW	0.72 lb/hr (0.41 g/hp-hr)	Low sulfur fuel, combustion control
OH-0266	UNIVERSITY OF CINCINNATI	8/15/2002	Diesel fired engines	19.17 MMBtu/hr	0.23 lb/hr (0.036 g/hp-hr)	None
OK-0129	CHOUTEAU POWER PLANT	1/23/2009	Emergency Diesel Generator	2200 HP	0.72 lb/hr (0.15 g/hp-hr)	None
WV-0023	MAIDSVILLE	3/2/2004	Emergency Generator	1801 HP	1.13 lb/hr (0.28 g/hp-hr)	Good Combustion Practices

The Mankato Energy Center Smal IC Engine limit does not apply as the proposed emission units are significantly larger. Also, the Mankato Energy Center Large IC Engine, and the University of Cincinnati emission units have NOx emissions of 12.7 g/hp-hr and 7.1 g/hp-hr, respectively, which are higher than the Tier 2 emissions standards and therefore cannot be used at the proposed facility. As shown in the above table, a proposed limit of 0.15 g/bhp-hr, which is equivalent to 0.00033 lb/hp-hr and 0.20 g/kW-hr, is consistent with the other limits contained in the RBLC.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**

The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ from the proposed Fire Pump Engines:

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Emergency Generators, Identified as EG01, EG02 and EG03 shall not exceed 0.15 g/hp-hr, each through the use of combustion design control and usage limitation.

(2) The Emergency Diesel Generators shall not exceed 500 hours per year, each.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for PM, PM_{10} and $PM_{2.5}$ for the Emergency Generators.

(1) The PM, PM_{10} and $PM_{2.5}$ emissions from the Emergency Diesel Generators, Identified as EG01, EG02 and EG03 shall not exceed 0.15 g/hp-hr, each through the use of combustion design control and usage limitation.

(2) The Emergency Diesel Generators shall not exceed 500 hours per year, each.

Carbon Monoxide (CO) BACT –Emergency Diesel Generators

Step 1: Identify Potential Control Technologies

Emissions of carbon monoxide (CO) are generally controlled by oxidation. Oxidation technologies include:

(a) Regenerative thermal oxidation;

(b) Recuperative thermal oxidizer

(c) Catalytic oxidation;

(d) Combustion Design Controls; and

(e) Flares.

(f) Usage Limitations

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers

The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, 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.

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.

This control is not included in RBLC for the control of CO emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

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 Emergency Diesel Generators at this source.

Recuperative Thermal Oxidizers
This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1.200^{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.

This control is not included in RBLC for the control of CO emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

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 Emergency Diesel Generators at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, 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 not included in RBLC for the control of CO emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is not a technically feasible option for Emergency Diesel Generators at this source.

Combustion Design Controls
CO emissions are caused through incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form where fuel will partially combust, resulting in 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. This type of control is included in RBLC for the control of CO emissions from fire pump & emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Good Combustion Controls is a technically feasible option for the Emergency Diesel Generators at this source

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 Emergency Diesel Generators at this source.

Usage Limitation
Usage limitation involves accepting a limit on the maximum hours of operation on the units, which results in lower emissions. This is included in RBLC for the control of CO emissions from fire pump and emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Usage Limitation is a technically feasible option for the Emergency Diesel Generators at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control and usage limitation shall be used to reduce the CO emissions from the Emergency Diesel Generators at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed CO BACT determination along with the existing CO BACT determinations for emergency engines. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Emergency Diesel Generators EG01 & EG02**	**1,006 horsepower, each**	**CO: 2.6 g/bhp-hr**	**Combustion Design Controls and Usage Limits**
			Emergency Generator EG03	**2,012 horsepower**		
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009	Emergency Generators	2000 KW	3.5 G/KW-H	Engine design and Operation. 15 ppm Sulfur fuel
AK-0060	SNAKE RIVER POWER PLANT	11/5/2004	Diesel Electric Generator	5211 KW	10.5 lb/hr (0.68 g/hp-hr)	Good Combustion Practices
MN-0071	FAIRBAULT ENERGY PARK	6/5/2007	Emergency Generators	1750 KW	0.0055 lb/hp-hr	None
FL-0310	SHADY HILLS GENERATING STATION	1/12/2009	Emergency Generators	2.5 MW	8.5 g/hp-hr	EPA Certification
ID-0018	LANGLEY GULCH POWER PLANT	6/25/2010	Emergency Generators Engine	750 KW	3.5 g/KW-hr	Tier 2 Engine Based, Good Combustion Practices (GCP)
MN-0054	MANKATO ENERGY CENTER	12/4/2003	IC Engine, Large	1850 HP	1 g/b-hp-hr	Good Combustion
MN-0054	MANKATO ENERGY CENTER	12/4/2003	IC Engine, Small	290 HP	0.25 g/b-hp-hr	Good Combustion
AR-0051	DUKE ENERGY-JACKSON FACILITY	4/1/2002	Generator Diesel Fired	671 HP	8.5 g/hp-hr	Good Operating Practice
WV-0023	MAIDSVILLE	3/2/2004	Emergency Generator	1801 HP	8.85 lb/hr (2.3 g/hp-hr)	Good Combustion Practices

The Mankato Energy Center Small IC Engine limit does not apply as the proposed units are significantly larger. Also, the Mankato Energy Center Large IC Engine, and the Snake River Power Plant units have NOx emissions of 12.7 g/hp-hr and 8.7 g/hp-hr, respectively, which are higher than the Tier 2 emissions standards and therefore cannot be used at the proposed facility. As shown in the above table, a proposed limit of 2.6 g/bhp-hr, which is equivalent to 3.5 g/kW-hr and 0.006 lb/bhp-hr, is consistent with all other limits contained in the RBLC.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for CO emissions from the proposed Emergency Diesel Generators, Identified as EG01, EG02 and EG03:

(1) The CO emissions from the Emergency Diesel Generators, Identified as EG01, EG02 and EG03 shall not exceed 2.6 g/hp-hr, each through the use of combustion design controls and usage limitation.

(2) The Emergency Diesel Generators shall not exceed 500 hours per year, each.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for CO emissions for the Emergency Generators.

(1) The CO emissions from the Emergency Diesel Generators, Identified as EG01, EG02 and EG03 shall not exceed 2.6 g/hp-hr, each through the use of combustion design controls and usage limitation.

(2) The Emergency Diesel Generators shall not exceed 500 hours per year, each.

Sulfur Dioxide (SO_2) BACT - Emergency Diesel Generators

Step 1: Identify Potential Control Technologies

Sulfur Dioxide (SO_2) emissions result from the oxidation of fuel-bound sulfur, with emissions dependent upon the sulfur content of the fuel. Sulfur Dioxide (SO_2) emissions are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

(a) Fuel Specification; and

(b) Good Combustion Practices.

(c) Usage Limitation.

Add-on control measures are generally based upon exposure of sulfur dioxide molecules to reagents that react with sulfur dioxide to form a sulfate molecule that can then be captured as a particulate. Sulfur dioxide control systems vary in reagent utilized to react with sulfur dioxide, the manner in which the reagent is exposed to sulfur dioxide, and the manner in which sulfate molecules are captured.

Step 2: Eliminate Technically Infeasible Options

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 SO_2 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 Emergency Diesel Generators at this source.

Good Combustion Practices
Good combustion practices as well as operation and maintenance of the Emergency Generators to keep them in good working order per the manufacturer's specifications will minimize SO_2 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 Emergency Diesel Generators at this source.

Usage Limitation
Usage limitation involves accepting a limit on the maximum hours of operation on the units, which results in lower emissions. This is included in RBLC for the control of SO2 emissions from fire pump and emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Usage Limitation is a technically feasible option for the Emergency Diesel Generators at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of ultra low sulfur distillate (ULSD) (Fuel Specification and Good combustion practices) and usage limitation shall be used to reduce the SO_2 emissions from the Emergency Diesel Generators at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed SO_2 BACT determination along with the existing SO_2 BACT determinations for emergency pumps. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Emergency Diesel Generators EG01 & EG02**	**1,006 horsepower, each**	**SO_2: 0.012 lb/hr**	**ULSD and Usage Limits**
			Emergency Generator EG03	**2,012 horsepower**	**SO_2: 0.024 lb/hr**	

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
CO-0055	LAMAR LIGHT & POWER POWER PLANT	2/3/2006	Fire Water Pump	1500 HP	0.06 lb/hr	Low Sulfur Fuel. Less than 0.05 by weight
NJ-0036	AES RED OAK LLC	10/24/2001	Emergency Generator	49 MMBtu/hr	2.45 lb/hr	Low Sulfur Fuel
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	8/14/2003	Emergency Generator	600 KW	0.4 lb/hr	Low Sulfur Fuel, Combustion Control
OH-0275	PSI ENERGY-MADISON STATION	8/24/2004	Emergency Generator	172.1 MMBtu/hr	8.61 lb/hr	Sulfur limited to 0.05% by Weight. Operation Limited to 499 Hours/yr
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	3/21/2009	IC Engine, Backup Generator Diesel	749 BHP	0.3 lb/hr	Use of Low Sulfur Fuel (<0.05% by Wt)
OK-0129	CHOUTEAU POWER PLANT	1/23/2009	Emergency Generator	2200 HP	0.89 lb/hr	Low Sulfur Diesel 0.05 % S

As shown in the above table, a proposed limit of 0.012 lb/hour for Emergency Generators, identified as EG01 & EG02 and 0.02 lbs/hr for Emergency Generator, identified as EG03, are consistent with the most stringent limits contained in the RBLC.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for SO_2 emissions from the proposed Emergency Generators, Identified as EG01, EG02 and EG03:

(1) The SO_2 emissions from the Emergency Diesel Generators, Identified as EG01 and EG02 shall be limited to less than 0.012 lb/hr through the use of ultra low sulfur distillate (ULSD) and usage limitation.

(2) The SO_2 emissions from the Emergency Diesel Generator, Identified as EG03 shall be limited to less than 0.024 lb/hr through the use of ultra low sulfur distillate (ULSD) and usage limitation.

(3) The Emergency Diesel Generators shall not exceed 500 hours per year, each.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for SO_2 emissions for the Emergency Generators.

(1) The SO_2 emissions from the Emergency Diesel Generators, Identified as EG01 and EG02 shall not exceed 0.012 lb/hr through the use of ultra low sulfur distillate (ULSD) and usage limitation.

(2) The SO_2 emissions from the Emergency Diesel Generator, Identified as EG03 shall not exceed 0.024 lb/hr through the use of ultra low sulfur distillate (ULSD) and usage limitation.

(3) The Emergency Diesel Generators shall not exceed 500 hours per year, each.

Volatile Organic Compounds (VOCs) BACT - Emergency Diesel Generators

Step 1: Identify Potential Control Technologies

Emissions of volatile organic compounds (VOC) are generally controlled by oxidation. Oxidation technologies include:

(a) Regenerative thermal oxidation;

(b) Recuperative thermal oxidation;

(c) Catalytic oxidation;

(d) Combustion Design Controls; and

(e) Flares

(f) Usage Limitation.

Step 2: Eliminate Technically Infeasible Options

Regenerative Thermal Oxidizers
The thermal oxidizer has a high temperature combustion chamber that is maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. This technology is typically applied for destruction of organic vapors, 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 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.

This control is not included in RBLC for the control of VOC emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

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 Emergency Diesel Generators at this source.

Recuperative Thermal Oxidizers
This control technology oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion. The operating temperature ranges from 1,100 - 1.200^{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 VOC from properly operated natural gas combustion units without the use of a catalyst.

This control is not included in RBLC for the control of VOC emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

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 Emergency Diesel Generators at this source.

Catalytic Oxidizers
Catalytic oxidation is also a widely used control technology to control pollutants where the waste gas is passed through a flame area and then through a catalyst bed for complete combustion of the waste in the gas. This technology is typically applied for destruction of organic vapors, nevertheless it is considered as a technology for controlling VOC emissions. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without 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 not included in RBLC for the control of VOC emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is not a technically feasible option for Emergency Diesel Generators at this source.

Combustion Design Controls
VOC emissions are caused through incomplete combustion. When fuel and air are not well mixed in the combustion zone, low oxygen regions form where fuel will partially combust, resulting in VOC and unburned hydrocarbons that exit with the exhaust. VOC 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. This type of control is included in RBLC for the control of VOC emissions from fire pump & emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Good Combustion Controls is a technically feasible option for the Emergency Diesel Generators at this source.

Flare
Although the VOC concentration is very low, the stream flow rate is very high. The low heating value of the stream is too low for flaring. As there are insufficient organics in this vent stream to support combustion, use of a flare would require a significant addition of supplementary fuel. Therefore, a secondary impact of the use of flare for this stream would be the creation of additional emissions from burning supplemental fuel, including NOx. Flares have not been utilized or demonstrated as a control device for 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 Emergency Diesel Generators at this source.

Usage Limitation
Usage limitation involves accepting a limit on the maximum hours of operation on the units, which results in lower emissions. This is included in RBLC for the control of VOC emissions from fire pump and emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Usage Limitation is a technically feasible option for the Emergency Diesel Generators at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control and usage limitation shall be used to reduce the VOC emissions from the Emergency Generators at this source.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination along with the existing VOC BACT determinations for emergency engines. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Emergency Diesel Generators EG01 & EG02**	**1,006 horsepower, each**	**VOC: 1.04 lbs/hr, each**	**Combustion Design Controls and Usage Limits**
			Emergency Generator EG03	**2,012 horsepower**	**VOC: 1.04 lbs/hr**	
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHENS	3/21/2009	IC Engine, Backup Generator Diesel	749 BHP	1.7 lb/hr	Good Engine Design

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
	ENERGY					
OK-0129	CHOUTEAU POWER PLANT	1/23/2009	Emergency Generator	2200 HP	1.55 lb/hr	Good Combustion Practice
WV-0023	MAIDSVILLE	3/2/2004	Emergency Generator	1801 HP	1.21 lb/hr	Good Combustion Practice
SC-0064	SCE&G - JASPER COUNTY GENERATIN G FACILITY	5/23/2002	Emergency Generator	2000 KW	1.7 lb/hr	None
OH-0254	DUKE ENERGY WASHINGT ON COUNTY LLC	8/14/2003	Emergency Generator	600 KW	1.76 lb/hr	Low Sulfur Fuel, Combustion Control
OH-0266	UNIVERSIT Y OF CINCINNATI	8/15/2002	Diesel fired engines	19.17 MMBtu/hr	1.04 lb/hr	None
OH-0275	PSI ENERGY-MADISON STATION	8/24/2004	Emergency Generator	17.21 MMBtu/hr	1.55 lb/hr	None

As shown in the above table, a proposed limit of 1.04 lb/hr is consistent with the most stringent limits contained in the RBLC.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for VOC emissions from the proposed Emergency Generators, Identified as EG01, EG02 and EG03:

(1) The VOC emissions from the Emergency Diesel Generators, Identified as EG01 and EG02 shall be limited to less than 1.04 lb/hr, each, through the use of Combustion Design Controls and usage limitation.

(2) The VOC emissions from the Emergency Diesel Generator, Identified as EG03 shall be limited to less than 1.04 lb/hr, each, through the use of Combustion Design Controls and usage limitation.

(3) The Emergency Diesel Generators shall not exceed 500 hours per year, each.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for VOC emissions for the Emergency Diesel Generators.

(1) The VOC emissions from the Emergency Diesel Generators, Identified as EG01 and EG02 shall not exceed 1.04 lbs/hr, each, through the use of Combustion Design Controls and usage limitation.

(2) The VOC emissions from the Emergency Diesel Generator, Identified as EG03 shall not exceed 1.04 lbs/hr, each, through the use of Combustion Design Controls and usage limitation.

(3) The Emergency Diesel Generators shall not exceed 500 hours per year, each.

Nitrogen Oxide (NOx) BACT - Emergency Diesel Generators

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) Combustion Design Controls

(d) Usage Limitations

Add-on control technologies and combustion control approaches are discussed below.

Step 2: Eliminate Technically Infeasible Options

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 sootblower.

This control is not included in RBLC for the control of NOx emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective catalytic reduction (SCR) is not a technically feasible option for the Emergency Diesel Generators at this source.

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.

This control is not included in RBLC for the control of NOx emissions from fire pump & emergency engines. EPA determined in the development of NSPS IIII that add-on controls are economically infeasible for emergency ICE.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that selective non-catalytic reduction (SNCR) is not a technically feasible option for the Emergency Diesel Generators at this source.

Combustion Design Controls
NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. These effects can be minimized through air-to-fuel ratio control, ignition timing reduction, and exhaust gas recirculation. This type of control is included in RBLC for the control of NO_X emissions from fire pump & emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Good Combustion Controls is a technically feasible option for the Emergency Diesel Generators at this source.

Usage Limitation
Usage limitation involves accepting a limit on the maximum hours of operation on the units, which results in lower emissions. This is included in RBLC for the control of NOx emissions from fire pump and emergency engines.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Usage Limitation is a technically feasible option for the Emergency Diesel Generators at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of combustion design control and usage limitation shall be used to reduce the NOx emissions from the Emergency Generators at this source.

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 emergency pumps. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	**Facility**	**Issued Date**	**Process Description**	**Rating (TPH)**	**Limitation**	**Control Method**
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Emergency Diesel Generators EG01 & EG02**	**1,006 horsepower, each**	**NOx + NMNC: 4.8 g/bhp-hr**	**Combustion Design Controls and Usage Limits**
			Emergency Generator EG03	**2,012 horsepower**		
AR-0051	DUKE ENERGY-JACKSON FACILITY	4/1/2002	Generator Diesel Fired	671 HP	14 g/b-hp-hr	Good Combustion Practice
FL-0310	SHADY HILLS GENERATING STATION	1/12/2009	Emergency Generator	2.5 MW	6.9 g/hp-hr	Purchased model is at least as stringent as the BACT values under EPA Certification
MN-0054	MANKATO ENERGY CENTER	12/4/2003	IC Engines Large Fuel Oil	1850 HP	12.7 g/b-hp-hr	Good Combustion Practice
MN-0054	MANKATO ENERGY CENTER	12/4/2003	IC Engines Small Fuel Oil	290 HP	5.7 g/b-hp-hr	Good Combustion Practice
MN-0071	FAIRBAULT ENERGY PARK	6/5/2007	Emergency Generator	1750 KW	0.024 lb/hp-hr	None
OK-0072	REDBUD POWER PLT	5/6/2002	Emergency Generator	1818 HP	0.024 lb/b-hp-hr	None
OK-0129	CHOUTEAU POWER PLANT	1/23/2009	Emergency Generator	2200 HP	23.15 lb/hr (4.8 g/hp-hr)	None
WV-0023	MAIDSVILLE	3/2/2004	Emergency Generator	1801 HP	20.9 lb/hr (5.3 g/hp-hr)	Good Combustion Practice
SC-0064	SCE&G - JASPER COUNTY GENERATING FACILITY	5/23/2002	Emergency Generator, Diesel Fuel	2000 KW	59.5 lb/hr (10.1 g/hp-hr)	None
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	8/14/2003	Emergency Generator	600 KW	12.4 lb/hr (7.0 g/hp-hr)	Low Sulfur Fuel, Combustion Control
OH-0266	UNIVERSITY OF CINCINNATI	8/15/2002	Diesel fired engines	19.17 MMBtu/hr	40.92 lb/hr (6.4 g/hp-hr)	None
OH-0275	PSI ENERGY-MADISON STATION	8/24/2004	Emergency Generator	172.1 MMBtu/hr	55.07 lb/hr (10.2 g/hp-hr)	None

As shown in the above table, a proposed limit of 4.8 g/bhp-hr NOx + NMHC, which is equivalent to 0.011 lb/bhp-hr, is consistent with the most stringent limits contained in the RBLC.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for NOx emissions from the proposed Emergency Generators, Identified as EG01, EG02 and EG03:

(1) The NOx emissions from the Emergency Diesel Generators shall be limited to less than 4.8 g/bhp-hr for NOx + NMHC through the use of Combustion Design Controls and usage limitation.

(2) The Emergency Generators shall not exceed 500 hours per year, each.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for NOx emissions for the Emergency Generators.

(1) The NOx emissions from the Emergency Diesel Generators shall not exceed 4.8 g/bhp-hr for NOx + NMHC through the use of Combustion Design Controls and usage limitation.

(2) The Emergency Diesel Generators shall not exceed 500 hours per year, each.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) BACT – Cooling Tower CT01 - CT02

Step 1: Identify Potential Control Technologies

Emissions of Particulate matter (PM, PM_{10} and $PM_{2.5}$) from cooling towers are generally controlled by:

(1) Drift (Mist) eliminator system.

(2) Minimizing TSD

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control option is whether it is both available and applicable to reducing the $PM/PM_{10}/PM_{2.5}$ emissions from the Cooling Towers.

Drift Eliminator System
Cooling towers are a source of particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions from the small amount of water mist that is entrained with the cooling air as “drift”. The cooling water contains small amounts of dissolved solids which become particulate ($PM/PM_{10}/PM_{2.5}$) emissions once the water mist evaporates. To reduce the drift from cooling towers, drift eliminators are typically incorporated into the tower design to remove as many droplets as practical from the air stream before exiting the tower.

Particulate matter emissions occur from cooling towers when suspended solids contained in water used in the cooling tower becomes airborne as the water is circulated and cooled. Drift eliminators contain packing which is used to limit the amount of this particulate matter which becomes airborne during the cooling process. As mist passes through the packing, the particles in the air contact and adhere to the surface of the packing. As condensed water flows down this packing, these particles are removed.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a drift eliminator system is technically feasible option for the Cooling Towers at this source.

Minimizing TSD
Minimizing dissolved solids in cooling water to reduce PM emissions. This system is included in RBLC for the control of PM emissions from cooling towers.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Minimizing TSD is a technically feasible option for the Cooling Towers at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Drift (Mist) eliminator system.

(2) Minimizing TSD

The most effective method for control of particulate emissions resulting from operation of the cooling towers at this source is the use of high efficiency drift eliminators designed to 0.0005% maximum drift to maintain a drift loss as well as the maintenance of the equipment in good working order and operation per manufacturer's specifications. The source has chosen the drift eliminator to control particulate matter from their Cooling Towers.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed PM, PM_{10} and $PM_{2.5}$ BACT determination along with the existing PM, PM_{10} and $PM_{2.5}$ BACT determinations for cooling towers. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Cooling Towers (CT01 and CT02)**	**170,000 gpm**	**0.0005%**	**Drift Eliminator**
AR-0070	GENOVA ARKANSAS I, LLC	8/23/2002	Cooling Towers	11 mmg/hr	0.001%	Drift Eliminator
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	4/3/2002	Cooling Towers	56 mmg/hr	0.005%	None
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	2/10/2009	Cooling Towers	121,000 gal/m	0.0005%	Drift/Mist Eliminator
ID-0017	POWER COUNTY ADVANCED ENERGY CENTER	2/10/2009	Cooling Towers	985 gal/m	0.001%	Drift/Mist Eliminator
GA-0141	WARREN COUNTY BIOMASS ENERGY FACILITY	12/1/2010	Cooling Towers	None	0.0005%	Drift Eliminator

BACT ID or Permit #	Facility	Issued Date	Process Description	Rating (TPH)	Limitation	Control Method
GA-0142	OSCEOLA STEEL CO.	12/29/2010	Cooling Towers	None	0.0005%	Drift Eliminator
LA-0248	DIRECT REDUCTION IRON PLANT	1/27/2011	Cooling Towers	26,857 gpm	0.0005%	less than 1000mg/l TSD concentration in cooling water and drift eliminator
LA-0248	DIRECT REDUCTION IRON PLANT	1/27/2011	Cooling Towers	17,611 gpm	0.0005%	less than 1000mg/l TSD concentration in cooling water and drift eliminator
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	8/16/2011	Cooling Towers	12,000 gal/min	0.001%	High efficiency Mist Eliminator
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	8/16/2011	Cooling Towers	115,847 gal/min	0.0005%	High efficiency Mist Eliminator

USEPA's RACT/BACT/LAER Clearinghouse shows BACT determinations specifying the use of drift/mist eliminators for controlling PM, PM_{10} and $PM_{2.5}$ emissions, with drift rates ranging from 0.003% – 0.0005%. A design drift rate of 0.0005% appears in the most recent permit determinations and it represents the best performing of all cooling towers in the RBLC and the highest efficiency mist eliminators available in the cooling tower design.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for PM, PM_{10} and $PM_{2.5}$ emissions from the proposed Cooling Tower (CT01-CT02):

Therefore, a 0.0005% drift (mist) eliminator system is proposed as BACT for PM, PM_{10} and $PM_{2.5}$ emissions from the Cooling Towers, identified as CT01 and CT02.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM, OAQ has approved the proposed PM, PM_{10} and $PM_{2.5}$ BACT for the Cooling Towers, identified as CT01 and CT02.

The PM, PM_{10} and $PM_{2.5}$ emissions from the Cooling Towers, identified as CT01 and CT02 shall be controlled by High efficiency drift eliminators designed with a drift loss rate of less than 0.0005%.

Volatile Organic Compounds (VOCs) BACT – Turbine Lube Oil Demister Vent DM01 – DM06

Step 1: Identify Potential Control Technologies

Emissions of Volatile Organic Compounds (VOCs) are generally controlled by oxidation. Oxidation technologies include regenerative thermal oxidation, catalytic oxidation, and flares.

(a) Catalytic oxidation;

(b) Regenerative thermal oxidation;

(c) Flares.

If add-on control technology is not feasible, an alternate method of control may be implemented.

Step 2: Eliminate Technically Infeasible Options

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 VOCs 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.

Catalyst can be deactivated by certain catalyst poisons or other fouling contaminants such as silicone, sulfur, heavy hydrocarbons, and particulates. The air flow from the lubrication oil vents and oil mist loading are sufficiently low to prohibit the use of any add-on controls to control VOC emissions from the lube oil vents.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is not a technically feasible option for Turbine Lube Oil Demister Vents at this source.

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 VOCs emissions. Upon passing through the flame, the waste gas containing VOCs is heated. The mixture continues to react as it flows through the combustion chamber.

The required level of VOCs destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of about 1,600^{o}F with a waste stream inlet flow rate of 10,000-100,000 scfm range. And a waste stream inlet pollutant concentration as low as 100 ppmv or less. 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.

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. The air flow from the lubrication oil vents and oil mist loading are sufficiently low to prohibit the use of any add-on controls to control VOC emissions from the lube oil vents.

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 Turbine Lube Oil Demister Vents at this source.

Flare
A flare is not technically feasible because the exhaust stream concentration must be high enough to sustain combustion, requiring a VOC inlet concentration of greater than 13,000 ppm, which is not feasible with this operation. They require a high heating value waste gas (in excess of 300 BTU/scf) or supplemental fuel. Flares will not be considered as BACT for this operation, and no additional analysis will be conducted.

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 Turbine Lube Oil Demister Vents at this source

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the VOC emissions resulting from the Turbine Lube Oil Demister Vents.

Step 4: Evaluate the Most Effective Controls and Document the Results

No BACT determinations for VOC emissions from Lubrication Oil Demister Vents were located in the RBLC data base. Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the VOC emissions resulting from Turbine Lube Oil Demister Vents.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for VOC emissions from the proposed Turbine Lube Oil Demister Vents:

The VOC emissions from the Turbine Lube Oil Demister Vents identified as DM01 – DM06 shall be the use of good design and operating practices.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for VOC emissions for the Turbine Lube Oil Demister Vents.

The VOC emissions from the Turbine Lube Oil Demister Vents identified as DM01 – DM06 shall be the use of good design and operating practices.

PM_{10} and $PM_{2.5}$ BACT – Turbine Lube Oil Demister Vent DM01 – DM06

Step 1: Identify Potential Control Technologies

The organic 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. Generally, organic PM (PM_{10} and $PM_{2.5}$) emissions are controlled through one of the following mechanisms:

(1) Mechanical Collectors (such as Cyclones or Multiclones);

(2) Wet Scrubbers;

(3) Electrostatic Precipitators (ESP); and

(4) Fabric Filter Dust Collectors (Baghouses).

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Step 2: Eliminate Technically Infeasible Options

Add - on - Controls
The organic PM (PM_{10} and $PM_{2.5}$) emissions from this source result only from the small amount of turbine lube oil used. This emissions level is so low that it would not be feasible for any add-on controls such as cyclones, baghouses, ESPs or wet scrubbers to effectively further reduce emissions. For this reason, the above-listed add-on particulate controls are not considered feasible in this BACT analysis. There is no evidence that any of these add-on controls have ever been used to control organic PM emissions from lube oil demister vents.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of add-on controls is not a technically feasible option for the Turbine Lube Oil Demister Vents at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the organic PM emissions resulting from the Turbine Lube Oil Demister Vents.

Step 4: Evaluate the Most Effective Controls and Document the Results

No BACT determinations for organic PM (PM_{10} and $PM_{2.5}$) emissions from Lubrication Oil Demister Vents were located in the RBLC data base. Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the organic PM (PM_{10} and $PM_{2.5}$) emissions resulting from Turbine Lube Oil Demister Vents.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for organic PM emissions from the proposed Turbine Lube Oil Demister Vents:

The organic PM, PM_{10} and $PM_{2.5}$ emissions from the Turbine Lube Oil Demister Vents identified as DM01 – DM06 shall be the use of good design and operating practices.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for organic PM (PM_{10} and $PM_{2.5}$) emissions for the Turbine Lube Oil Demister Vents.

The organic PM, PM_{10} and $PM_{2.5}$ emissions from the Turbine Lube Oil Demister Vents identified as DM01 – DM06 shall be the use of good design and operating practices.

Volatile Organic Compounds (VOCs) BACT - Storage Tanks

(a) Six (6) Turbine Lube Oil storage tanks, identified as TK01 - TK06, permitted in 2012, with a nominal capacity of 6,800 gallons each.

(b) Two (2) Emergency Generator ULSD Tanks, identified as TK07 and TK08, permitted in 2012, with a nominal capacity of 550 gallons, each.

(c) Two (2) Fire Pump Engine ULSD Tanks, identified as TK09 and TK10, permitted in 2012, with a nominal capacity of 70 gallons, each.

(d) One (1) Vehicle Diesel Tank, identified as TK12, permitted in 2012, with a nominal capacity of 650 gallons.

(e) One (1) Emergency Generator ULSD Tank, identified as TK50, permitted in 2012, with a nominal capacity of 300 gallons.

The VOC emissions from the above diesel storage Tanks are less than 0.01 tons per year, each.

Step 1: Identify Potential Control Technologies

Emissions of Volatile Organic Compounds (VOCs) are generally controlled by oxidation. Oxidation technologies include regenerative thermal oxidation, catalytic oxidation, and flares.

(a) Catalytic oxidation;

(b) Regenerative thermal oxidation;

If add-on control technology is not feasible, an alternate method of control may be implemented.

Step 2: Eliminate Technically Infeasible Options

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 VOCs 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.

Catalyst can be deactivated by certain catalyst poisons or other fouling contaminants such as silicone, sulfur, heavy hydrocarbons, and particulates. The air flow from the storage tanks is sufficiently low to prohibit the use of any add-on controls to control VOC emissions.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a catalytic oxidizer is not a technically feasible option for Storage Tanks at this source.

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 VOCs emissions. Upon passing through the flame, the waste gas containing VOCs is heated. The mixture continues to react as it flows through the combustion chamber.

The required level of VOCs destruction of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Most thermal units are designed to provide no more than 1 second of residence time to the waste gas with typical temperatures of about 1,600^{o}F with a waste stream inlet flow rate of 10,000-100,000 scfm range. And a waste stream inlet pollutant concentration as low as 100 ppmv or less. 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.

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. The air flow from the storage tanks is sufficiently low to prohibit the use of any add-on controls to control VOC emissions.

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 Storage Tanks at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the VOC emissions resulting from the Storage Tanks.

Step 4: Evaluate the Most Effective Controls and Document the Results

No BACT determinations for VOC emissions from Storage Tanks were located in the RBLC data base. Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that there is no viable technology for controlling the VOC emissions resulting from Storage Tanks.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for VOC emissions from the proposed Storage Tanks:

The VOC emissions from the Storage Tanks, identified as TK01, TK02, TK03, TK04, TK05, TK06, TK07, TK08, TK09, TK10, TK12 and TK50 shall be the use of good design and operating practices.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for VOC emissions for the Storage Tanks.

The VOC emissions from the Turbine Lube Oil storage tanks, identified as TK01 - TK06, and Diesel Storage Tanks, identified as TK07, TK08, TK09, TK10, TK12 and TK50 shall be the use of good design and operating practices.

Volatile Organic Compounds (VOCs) BACT - Gasoline Storage Tank

(a) One (1) Vehicle Gasoline dispensing Tank, identified as TK11, permitted in 2012, with a nominal capacity of 650 gallons, equipped with submerged fill and stage 1 vapor balance.

Step 1: Identify Potential Control Technologies

Emissions of Volatile Organic Compounds (VOCs) are generally controlled by oxidation. Oxidation technologies include regenerative thermal oxidation, catalytic oxidation, and flares.

(a) Catalytic oxidation;

(b) Regenerative thermal oxidation;

(c) Flares.

If add-on control technology is not feasible, an alternate method of control may be implemented.

Step 2: Eliminate Technically Infeasible Options

Add - on - Controls
The VOC emissions from this source are so low that it would not be feasible for any add-on controls such as Catalytic oxidation, Regenerative thermal oxidation and Flares to effectively further reduce emissions. For this reason, the above-listed add-on VOCs controls are not considered feasible in this BACT analysis. There is no evidence that any of these add-on controls have ever been used to control VOC emissions from the gasoline dispensing tanks.

The only add on control technologies used in practice for reducing VOC emission from the gasoline dispensing are the use of a submerged fill pipes when filling storage tanks, Stage I vapor control, Stage II vapor control and equipping vehicles with on-board vapor recovery system (ORVR).

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of submerged fill pipes and Stage I vapor control shall be used to reduce the VOC emissions from the Vehicle Gasoline Dispensing Tank at this source..

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table lists the proposed VOC BACT determination along with the existing VOC BACT determinations for gasoline dispensing operation. All data in the table is based on the information obtained from the permit application submitted by St. Joseph Energy Center, LLC, the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), and electronic versions of permits available at the websites of other permitting agencies.

BACT ID or Permit #	Facility	Issued Date	Process Description	Limitation (Tons/year)	Control Method
Draft Permit No. 141-31003-00579 Proposed Limit	**St. Joseph Energy Center - *proposed***	**Proposed**	**Gasoline Dispensing Operation (TK11)**	**0.11**	**Submerged fill pipes and Stage I vapor control**
SPM 031-26051-00026	Honda Manufacturing of Indiana, LLC – Greensburg, IN	5/12/2008	Gasoline Dispensing Operation	0.81	Submerged fill Stage I vapor control for filling the storage tanks. Use of on-board vapor recovery (ORVR) on a minimum of 95% of vehicles manufactured
T031-23360-00026	Honda Manufacturing of Indiana, LLC – Greensburg, IN	10/19/2006	Gasoline Dispensing Operation	No limit	Submerged fill Stage I vapor control Use of on-board vapor recovery or Stage II vapor control on vehicles manufactured
AL-0191	Hyundai Motor Manufacturing - Montgomery Co, AL	3/23/04	Gasoline Dispensing Operation	No limit identified	Submerged fill pipes, Stage 1 vapor control on large gasoline tanks
AL-0192	Honda Mfg. of Alabama LLC - Talladega Co., AL	10/18/02	Storage tanks	No emission rate limits. BACT is control.	Submerged fill Stage 1 vapor control

Based on the RBLC entries in the above table, the most stringent PSD BACT for gasoline dispensing is still the same using Submerged fill and Stage I vapor control for filling the storage tanks.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**

The following has been proposed as BACT for VOC emissions from the proposed Storage Tanks:

The VOC emissions from the Vehicle Gasoline Dispensing Operation, identified as TK11 shall be controlled by submerged fill pipes and Stage I vapor control

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for VOC emissions for the Gasoline Dispensing Operation.

The VOC emissions from the Vehicle Gasoline Dispensing Operation, identified as TK11 shall be the use of submerged fill pipes and Stage I vapor control.

GHGs BACT – Combined Cycle Combustion Turbines CCCT1 - CCCT4

Step 1: Identify Potential Control Technologies

The 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 gas-fired units. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions (CO2e).

(1) Carbon Capture and Storage (CCS); and

(2) High Thermal Efficiency Design.

Step 2: Eliminate Technically Infeasible Options

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 turbines at this source.

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 turbines at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only feasible, applicable and available control technologies identified is:

(1) High Thermal Efficiency Design

Step 4: Evaluate the Most Effective Controls and Document the Results

The mass emissions limit is based on the maximum rated heat input capacity of the combustion turbines and HRSG duct burners needed to produce the power generation demand that the CCCT Facility is designed to serve. The source propose to comply with the mass based emission limit via continuous fuel usage monitoring and records of the calculated heat input and mass GHG emissions.

The heat rate BACT limit of 7,646 Btu/kW-hr (HHV) is determined by applying a "reasonable margin of compliance" of 12.8 percent to the design net base heat rate of the CCCT blocks. A margin of compliance of 12.8 percent over the design base heat rate is consistent with the GHG BACT analyses performed for the Russell City Energy Center project, a proposed 600 MW natural gas fired combined-cycle power plant proposed to be located in Hayward, California, and the Cricket Valley Energy Center project, a nominal 1,000 MW natural gas fire combined cycle power plant to be located in Dover, New York. The margin of compliance accounts for the following degradation factors:

(1) Design margin to reflect that the current baseline performance values are preliminary estimates absent equipment supplier commercial guarantees and the equipment as constructed and installed may not fully achieve the assumptions that went into the design calculations,

(2) A reasonable performance degradation margin to reflect normal wear and tear over the life of the combustions turbines, heat recovery steam generator, and steam turbine generator, and

(3) A reasonable degradation margin based on normal wear and tear over the life of the auxiliary plant equipment (e.g., cooling towers).

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for GHG emissions from the proposed combined cycle combustion turbines:

(1) The CO_2 emissions shall be limited to less than 7,646 Btu/kW-hr (HHV-net) for each CCCT block (ISO conditions, without duct firing or inlet evaporative cooling, and not accounting for transformer losses).

(2) The total CO_2 emissions from all four CCCT blocks shall be limited to less than 4,885,000 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

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 turbines:

(1) The net heat rate shall not exceed 7,646 Btu/kW-hr (HHV-net) for each CCCT block (ISO conditions, baseload operation without duct firing or inlet evaporative cooling, and not accounting for transformer losses).

(2) The total CO_{2e} emissions from all four CCCT blocks shall not exceed 4,736,936 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

GHGs BACT – Auxiliary Boilers B001 - B002

Step 1: Identify Potential Control Technologies

The 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 gas-fired units. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

(1) Operating and Maintenance (O&M) Practices;

(2) Efficient Burner Design;

(3) Improved Combustion Measures: Combustion Tuning;

(4) Improved Combustion Measures: Optimization & Digital Control System;

(5) Air Preheat & Economizers;

(6) Turbulators for Firetube Boilers;

(7) Boiler Insulation;

(8) Minimization of Air Infiltration;

(9) Boiler Blowdown Heat Exchange;

(10) Condensation Return System;

(11) Minimization of Gas-side heat Transfer Surface Deposits;

(12) Steam Line Maintenance;

(13) Alternative Fuels-Biomass/Co-firing; and

(14) Fuel Switching.

Step 2: Eliminate Technically Infeasible Options

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.

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.

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.

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.

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 NO_X. 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.

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 economic 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.

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.

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.

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.

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.

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.

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 stream line maintenance is a technically feasible option for the Auxiliary Boilers at this source.

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 fuels 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.

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

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. 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. As part of the O&M practices, the air handling systems for each boiler will be periodically inspected for leaks and combustion tuning of boilers will be conducted on an as-needed basis to address any decreases in boiler efficiency over time.

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.

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**
The following has been proposed as BACT for GHG emissions from the proposed auxiliary boilers:

(1) Operating and Maintenance (O&M) Practices;

(2) Combustion Turning;

(3) The boiler will be equipped with oxygen trim controls and oxygen analyzers;

(4) The boiler will be equipped with an economizer;

(5) Energy efficient refractory will be installed;

(6) The boiler will be equipped with a condensate return system (recovery);

(7) Steam and hot lines will be insulated;

(8) Boiler designed for 80% thermal efficiency (HHV); and

(9) The total CO_{2e} emissions from the two auxiliary boilers shall not exceed 81,996 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

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 Auxiliary Boilers:

(1) Operating and Maintenance (O&M) Practices;

(2) Combustion Turning;

(3) The boiler will be equipped with oxygen trim controls and oxygen analyzers;

(4) The boiler will be equipped with an economizer;

(5) Energy efficient refractory will be installed;

(6) The boiler will be equipped with a condensate return system (recovery);

(7) Steam and hot lines will be insulated;

(8) Boiler designed for 80% thermal efficiency (HHV); and

(9) The total CO_{2e} emissions from the two auxiliary boilers shall not exceed 81,996 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

GHGs BACT – Emergency Generators

Step 1: Identify Potential Control Technologies

The 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

Good Engineering Design and Fuel Efficient Design

The source will install engines meeting the latest efficiency and pollutant performance standards specified in NSPS Part 60 Subpart IIII and NESHAP Part 63 Subpart ZZZZ. These Diesel engines are built with automatic control of the air to fuel ratio that ensures that they operate when needed and meet the applicable standards.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good engineering design and Fuel efficient design is a technically feasible option for the Emergency 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 the 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

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

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**

The following has been proposed as BACT for GHG emissions from the proposed Emergency generators engines: the selection and use of good engineering design and fuel efficient design.

This project includes two (2) diesel-fired 750 KW and one (1) diesel-fired 1,500 KW standby emergency generators. These engines are required for safety reasons. Each engine is expected to operate less than 500 hours per year each. That use is associated with assuring their readiness in an emergency. These emergency diesel engines will have the potential to emit greenhouse gases (CO_2, CH_4, and N_2O) because they will combust a hydrocarbon fuel. However, because their normal use is limited to routine maintenance, inspection and testing, their total emissions are very small (less than 600 tons CO_2e/yr, each).

The following has been proposed as BACT for GHG emissions from the proposed Emergency Diesel Generators:

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

(2) The total CO_{2e} emissions from all the three (3) emergency diesel generators shall be limited to less than 1,200 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

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 Emergency Diesel Generators:

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

(2) The total CO_{2e} emissions from all the three (3) emergency diesel generators shall not exceed 1,186 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

GHGs BACT – Firewater Pumps

Step 1: Identify Potential Control Technologies

The 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

Good Engineering Design and Fuel Efficient Design

The source will install engines meeting the latest efficiency and pollutant performance standards specified in NSPS Part 60 Subpart IIII and NESHAP Part 63 Subpart ZZZZ. These Diesel engines are built with automatic control of the air to fuel ratio that ensures that they operate when needed and meet the applicable standards.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Good engineering design and Fuel efficient design is a technically feasible option for the Firewater pumps 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 the 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 Firewater pumps at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only feasible, applicable and available control technology identified to reduce greenhouse gases from the firewater pump diesel engines is to utilize good engineering design and fuel efficient design.

Step 4: Evaluate the Most Effective Controls and Document the Results

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**

The following has been proposed as BACT for GHG emissions from the proposed Firewater pump diesel engines: the selection and use of good engineering design and fuel efficient design.

This project includes two (2) diesel-fired 371 hp standby fire water pumps. These engines are required for safety reasons. Each engine is expected to operate less than 500 hours per year each. That use is associated with assuring their readiness in an emergency. These emergency diesel engines will have the potential to emit greenhouse gases (CO_2, CH_4, and N_2O) because they will combust a hydrocarbon fuel. However, because their normal use is limited to routine

maintenance, inspection and testing, their total emissions are very small (less than 100 tons CO_2e/yr, each).

The following has been proposed as BACT for GHG emissions from the proposed Firewater Pump Engines:

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

(2) The total CO_{2e} emissions from all the two (2) firewater pump engines shall be limited to less than 180 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

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 Firewater Pump Engines:

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

(2) The total CO_{2e} emissions from all the two (2) firewater pump engines shall not exceed 172 tons of CO_2e per twelve (12) consecutive month period with compliance determined at the end of the month.

GHGs BACT – Circuit Breakers SF_6

Step 1: Identify Potential Control Technologies

GHG control possibilities identified and addressed in this BACT analysis for these small potential sources are:

(1) Alternative Technology.
(2) Alternative Dielectric Material.

Step 2: Eliminate Technically Infeasible Options

Alternative Technology
The use of fully enclosed circuit breakers with leak detection (low pressure alarm) is state-of-the-art for circuit breakers and is proposed by SJEC. A low pressure alarm is installed on each breaker to alert operators of a loss of SF_6 gas. Operators will investigate the cause of any alarm and take corrective measures to stop the leak if one exists.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of alternative technology is a technically feasible option for the Circuit Breaker at this source.

Alternative Dielectric Material
There is no practical alternative to the use of SF_6 as the insulator and arc quenching substance in SJEC's circuit breakers. The unique performance qualities of SF_6 breakers is further supported by the most recent report released by the EPA SF_6 Partnership, which states: "no clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties." Research and development efforts have focused on finding substitutes for SF_6 that have comparable insulating

and arc quenching properties in high-voltage applications. While some progress has reportedly been made in medium- or low-voltage applications, most studies have concluded, "that there is no replacement gas immediately available to use as an SF_6 substitute" for high-voltage applications. Therefore, the use of a breaker that doesn't contain SF_6 is judged as not feasible for this application.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of Alternative Dielectric Material is not a technically feasible option for the Circuit Breaker at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) The use of totally enclosed and pressurized circuit breakers with a density alarm for leak detection.

Step 4: Evaluate the Most Effective Controls and Document the Results

Proposal: **St. Joseph Energy Center, LLC** – **New Carlisle, Indiana**

The following has been proposed as BACT for GHGs from the proposed Electric Circuit Breaker:

(1) The use of totally enclosed and pressurized circuit breakers with a design leak rate of 0.5% and a density alarm for leak detection.

(2) The total SF_6 emissions from all the circuit breakers shall be limited to less than 0.0009 tons of SF_6 per twelve (12) consecutive month period with compliance determined at the end of the month.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Prevention of Significant Deterioration (PSD), IDEM has established the following as BACT for GHGs for Electrical Circuit Breaker.

(1) The use of totally enclosed pressure system with a design leak rate of 0.5% and a density alarm for leak detection.

(2) The total SF_6 emissions from all the circuit breakers shall not exceed 0.0009 tons of SF_6 per twelve (12) consecutive month period with compliance determined at the end of the month.

Best Available Control Technology during Startup and Shutdown for the Combustion Turbines, identified as CCCT1-CCCT4.

(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 consecutive CEMS data points in compliance with the primary BACT limits.

(b) Steady-state operating condition shall be defined as the period of time that the combustion turbine is operating in dry low NOx (premix) mode and in compliance with the primary BACT limit.

(c) A shutdown is defined as operation beginning when the combustion turbine exits dry low-NOx (premix) mode and ending with termination of continuous fuel flow to each turbine.

(d) A startup/shutdown cycle is a pair of subsequent shutdown and startup events (i.e., one startup followed by one shutdown represents one startup/shutdown cycle).

(e) Unit Offline is represented by the Unit on-line Time being 0.

(f) 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.

(g) An event is defined as:

(1) exactly one (1) startup or exactly one (1) shutdown

For CO and NO_X, the source determined the worst-case operating scenario that results in the highest modeled impacts to be a cold start of the CCCTs. The modeled cold start emission rates are based on startup emission totals provided by the turbine vendor. Therefore, the source proposes to use the cold start emission totals, per CCCT as a short-term limit during startup/shutdown events, as follows:

CO - 2,125 lb/event

NOx - 443 lb/event

(h) The NO_X emissions from the combined cycle combustion turbines stacks shall not exceed 81.6 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.

(i) The CO emissions from the combined cycle combustion turbines stacks shall not exceed 407.5 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.

(j) The VOC emissions from the combined cycle combustion turbines stacks shall not exceed 22.0 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.

Air Quality Analysis

St Joseph Energy Center, LLC

New Carlisle, Indiana (St. Joseph County)

Tracking and Plant ID: 141-31003-00579

Proposed Project

St Joseph Energy Center, LLC (SJE) first submitted their PSD modeling in October 2011. SJE proposes to construct and operate a 1,200 megawatt (MW) combined cycle combustion turbine (CCCT) electric generating facility in St Joseph County, in New Carlisle, Indiana.

Trinity Consultants (Trinity) was the consultant who prepared the modeling portion of the permit application for SJE. This technical support document provides the air quality analysis review of the submitted modeling by Trinity for SJE but revised by the Indiana Department of Environmental Management (IDEM).

Analysis Summary

Based on the potential emissions after controls, a PSD air quality analysis was triggered for SO_2, PM_{10}, $PM_{2.5,}$ CO, NO_2, and sulfuric acid mist. The significant impact analysis for CO, SO_2, PM_{10}, and annual NO_2 determined that modeling concentrations did not exceed the significant impact levels. A refined analysis was required for the 1-hour NO_2 and $PM_{2.5}$ standards. No NAAQS violations were modeled for NO_2. NAAQS violations did occur for the 24-hour $PM_{2.5}$ but SJE was below significance whenever the violations occurred. SJE was below the 24-hour PM_{10} as well as both annual and 24-hour $PM_{2.5}$ PSD increment. Pre-construction monitoring requirements are not necessary since existing monitoring is available. Hazardous Air Pollutants were below the 25 ton per year total and 10 ton per year individual pollutant thresholds. An additional impact analysis was conducted and showed no significant impact.

Air Quality Impact Objectives

The purpose of the air quality impact analysis in the permit application is to accomplish the following objectives. Each objective is individually addressed in this document in each section outlined below.

A. Establish which pollutants require an air quality analysis based on PSD significant emission rates.

B. Provide analyses of actual stack heights with respect to Good Engineering Practice (GEP), the meteorological data used, a description of the model used in the analysis, and the receptor grid utilized for the analyses.

C. Determine the significant impact level, the area impacted by the source's emissions, and background air quality levels.

D. Demonstrate that the source will not cause or contribute to a violation of the National Ambient Air Quality Standard (NAAQS) or PSD increment if the applicant exceeds significant impact levels.

E. Perform a qualitative analysis of the source's impact on general growth, soils, vegetation, and visibility in the impact area with emphasis on any Class I areas. The nearest Class I area is Kentucky's Mammoth Cave National Park.

F. Analysis of Secondary Ozone formation

G. Analysis of Secondary $PM_{2.5}$ formation

H. Summarize the Air Quality Analysis

Section A - Pollutants Analyzed for Air Quality Impact

Applicability

The PSD requirements, 326 IAC 2-2, apply in attainment and unclassifiable areas and require an air quality impact analysis of each regulated pollutant emitted in significant amounts by a major stationary source or modification. Significant emission levels for each pollutant are defined in 326 IAC 2-2-1 and in the Code of Federal Regulations (CFR) 52.21(b) (23) (i).

Proposed Project Emissions

PM_{10}, $PM_{2.5}$, NO_2, SO_2, Sulfuric Acid Mist and CO are the pollutants that will be emitted from SJE and are summarized below in Table 1. PM_{10}, $PM_{2.5}$, NO_2, SO_2, and CO potential emissions after controls exceed the PSD Significant Emission Rates and therefore require an air quality analysis. Sulfuric acid mist also exceeds the PSD Significant Emission Rate but does not require an air quality impact analysis under current PSD regulations.

TABLE 1
Significant Emission Rates for PSD

POLLUTANT	**SOURCE EMISSION RATE** (Facility totals in tons/year)	**SIGNIFICANT EMISSION RATE** (tons/year)	**PRELIMINARY AQ ANALYSIS REQUIRED**
PM_{10}	343.4	15	Yes
$PM_{2.5}$	339.3	10	Yes
NO_2	291.7	40	Yes
SO_2	93.0	40	Yes
CO	554.5	100	Yes
Sulfuric Acid Mist[1]	71.8	7	No[1]

[1] Sulfuric Acid Mist has no monitoring threshold or National Ambient Air Quality Standard. No AQ analysis is required for Sulfuric Acid Mist under the PSD regulations.

Section B – Good Engineering Practice (GEP), Met Data, Model Used, Receptor Grid and Terrain

Stack Height Compliance with Good Engineering Practice (GEP)

Stacks should comply with GEP requirements established in 326 IAC 1-7-4. If stacks are lower than GEP, excessive ambient concentrations due to aerodynamic downwash may occur. Dispersion modeling credit for stacks taller than 65 meters (213 feet) is limited to GEP for the purpose of establishing emission limitations. The GEP stack height takes into account the distance and dimensions of nearby structures, which affects the downwind wake of the stack. The downwind wake is considered to extend five times the lesser of the structure's height or width. A GEP stack height is determined for each nearby structure by the following formula:

$$Hg = H + 1.5L$$

Where: Hg is the GEP stack height
H is the structure height
L is the structure's lesser dimension (height or width)

New Stacks

Since all of the new stack heights for SJE are below GEP stack height, the effect of aerodynamic downwash is accounted for in the air quality analysis for the project.

Meteorological Data

The National Weather Service (NWS) 1-minute Automated Surface Observation Station (ASOS) meteorological data used in the air quality analysis consisted of 2006 through 2010 surface data from South Bend, Indiana and upper air measurements taken at Lincoln, Illinois. The meteorological data was preprocessed using the latest versions of AERMINUTE, AERSURFACE, and AERMET.

Model Description

The Office of Air Quality (OAQ) used AERMOD version 12060 in their air quality analysis review to determine maximum off-property concentrations or impacts for each pollutant. All regulatory default options were utilized in the U.S. EPA approved model, as listed in the 40 Code of Federal Register Part 51, Appendix W “Guideline on Air Quality Models”.

Receptor Grid

OAQ modeling used the same receptor grids generated by Trinity. The receptor grid is outlined below:

- 100 meter spacing along the facility’s property boundary,
- 100 meter spacing from the property boundary to 3000 meters,
- 500 meters spacing from 3000 meters to 10000 meters.
- 1000 meters spacing from 10000 meters to 20000 meters
- 2500 meters spacing from 20000 meters to 50000 meters

Treatment of Terrain

Receptor terrain elevation inputs were interpolated from NED (National Elevation Dataset) data obtained from the USGS. NED terrain data was preprocessed using AERMAP.

Section C - Significant Impact Level/Area (SIA) and Background Air Quality Levels

A significant impact analysis was conducted to determine if the source would exceed the PSD significant impact levels (concentrations). Depending on pollutant and averaging times, either 16 or 25 different operating scenarios were modeled and the highest impacts were considered. A complete discussion of the different operating scenarios can be found in their application. If the source's concentrations exceed these significant impact levels, further air quality analysis is required. Refined modeling for CO, SO_2 , PM_{10},and annual NO_2 was not required because the results did not exceed significant impact levels. The $PM_{2.5}$ and 1-hour NO_2 exceeded their significant impact levels and required refined modeling. Significant impact levels are defined by the following time periods in Table 2 below, with all maximum-modeled concentrations from the worst case operating scenarios. A Tier II 80% conversion of NO to NO_2 was assumed based on the March 01, 2011, Tyler Fox memorandum.

TABLE 2
Significant Impact Analysis[3]

POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED IMPACTS (ug/m^3)	SIGNIFICANT IMPACT LEVEL (ug/m^3)	REFINED AQ ANALYSIS REQUIRED
NO_2	Annual[1]	0.97	1	No
NO_2	1-hour[2]	105.9	7.55	Yes
PM_{10}	Annual[1]	0.49	1	No
PM_{10}	24-hour[1]	4.8	5	No
$PM_{2.5}$	Annual[2]	0.47	0.3	Yes
$PM_{2.5}$	24-hour[2]	4.7	1.2	Yes
SO_2	3-hour[1]	2.9	25	No
SO_2	24-hour[1]	1.2	5	No
SO_2	Annual[1]	0.11	1	No
SO_2	1-hour[2]	5.0	7.80	No
CO	1-hour[1]	627	2000	No
CO	8-hour[1]	129	500	No

[1]First highest values per EPA NSR manual October 1990.
[2] In accordance with recent U.S. EPA guidance, the highest modeled concentration may be averaged over the five years modeled for comparison with the 1-hour NO_2, 1-hour SO_2, 24-hour $PM_{2.5}$, and the annual $PM_{2.5}$ SIL. See the March 01, 2011 and the March 23, 2010 memorandums
[3]Impacts are from SJE only.

Pre-construction Monitoring Analysis

Applicability

The PSD rule, 326 IAC 2-2-4, requires an air quality analysis of the new source or the major modification to determine if the pre-construction monitoring threshold is triggered. In most cases, monitoring data taken from a similar geographic location can satisfy this requirement if the pre-construction monitoring threshold has been exceeded. Also, post construction monitoring could be required if the air quality in that area could be adversely impacted by applicant's emissions.

Modeling Results

The modeling results were compared to the PSD preconstruction monitoring thresholds. The results are shown in the table below.

TABLE 3
Preconstruction Monitoring Analysis

POLLUTANT	TIME AVERAGING PERIOD	MAXIMUM MODELED IMPACTS (ug/m^3)	DEMINIMIS LEVEL (ug/m^3)	ABOVE DE MINIMIS LEVEL
NO_2	Annual[1]	0.97	14	No
PM_{10}	24-hour[1]	4.8	10	No
$PM_{2.5}$	24-hour[2]	4.7	4	Yes
SO_2	24-hour[1]	1.2	13	No
CO	8-hour	129	575	No

[1]First highest values per EPA NSR manual October 1990. Maximum modeled impacts are from SJE only.
[2] In accordance with recent U.S. EPA guidance, the highest modeled concentration may be averaged over the five years. See the March 01, 2011 and the March 23, 2010 memorandums from EPA.

NO_2, CO, PM_{10}, and SO_2 did not trigger the preconstruction monitoring threshold level. SJE can satisfy the preconstruction monitoring requirement for $PM_{2.5}$ since there is existing air quality monitoring data representative of the area within St. Joseph County.

Background Concentrations

Applicability

EPA's "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (EPA-450/4-87-007) Section 2.4.1 is cited for approval of the monitoring sites chosen for this area.

Background Monitors

Background data was taken from representative monitoring stations for SJE. The background design value was used for $PM_{2.5}$. It was agreed between SJE and OAQ that this approach be taken in place of the preconstruction monitoring requirement.

TABLE 4
Existing Monitoring Data Used For Background Concentrations *

Pollutant	Location	Monitoring Site	Averaging Period	Concentration (ug/m^3)
$PM_{2.5}$	Shields Drive, South Bend, IN	18-141-0015	24-hour	28.0
$PM_{2.5}$	Shields Drive, South Bend, IN	18-141-0015	Annual	11.0
NO_2	Shields Drive, South Bend, IN	18-141-0015	1-hour	69.6

* $PM_{2.5}$ and NO_2 used the design value.

Section D - NAAQS and PSD Increment

NAAQS Compliance Analysis and Results

OAQ supplied emission inventories of all point sources in Indiana within a 50-kilometer radius of SJE. The NAAQS inventories are generated from EMITS **(**Emission Inventory Tracking System) in accordance with 326 IAC 2-6. The PSD increment inventories include sources that affect the increment and are compiled from permits issued by OAQ. The Michigan Department of Environmental Quality supplied emission inventories for Michigan.

OAQ modeling results are shown in Table 5. All maximum-modeled concentrations were compared to the respective NAAQS limit. All maximum-modeled concentrations during the five years were below the NAAQS limit except for the 24-hour $PM_{2.5}$ and a culpability analysis was required and is shown in Table 6. Results were based on the worst operating scenario determined in SIA modeling.

TABLE 5[1]
NAAQS Analysis

Pollutant	Year	Time-Averaging Period	Maximum Concentration (ug/m^3)	Background Concentration (ug/m^3)	Total (ug/m^3)	NAAQS Limit (ug/m^3)	NAAQS Violation
NO_2	2006-2010	1-hour	110.0[2]	69.6	**179.6**	189	No
$PM_{2.5}$	2006-2010	24-hour	30.4[2]	28.0	**58.4**	35	Yes
$PM_{2.5}$	2006-2010	Annual	0.86	11.0	**11.9**	15	No

[1] Any differences between the maximum concentration numbers in Tables 5 and 6 are due to different sources used for the NAAQS and the increment inventories.
[2] In accordance with recent U.S. EPA guidance, the highest modeled concentration may be averaged over the five years. See the March 23, 2010, memorandum from EPA.

Table 6
Culpability Analysis

Highest Predicted 24-hour $PM_{2.5}$ Concentration from Cumulative Analysis for SJE ($\mu g/m^3$)						
Maximum Modeled Concentration SJE + Inventory Sources	Background Design Value South Bend, IN	Concentration (modeled + background)	Contribution from Modeled Nearby Sources	Contribution from SJE at peak	Is the Total Concentration ≥ NAAQS of 35 $\mu g/m^3$?	Is the SJE contribution ≥ SIL of 1.2 $\mu g/m^3$?
29.0	28.0	**57.0**	29.0	**0.0**	yes	**no**

Every 24-hour modeled exceedence was examined to determine SJE's impact on that day at that receptor. A table of these values can be found in the Appendix. Even though the modeled impact plus background was over the NAAQS, SJE was never above the significant impact level, and often had 0.0 ug/m^3 impact. Therefore, SJE does not cause or contribute to a violation of the NAAQS.

Analysis and Results of Source Impact on the PSD Increment

Applicability

Maximum allowable increases (PSD increments) are established by 326 IAC 2-2 for $PM_{2.5}$. This rule also limits a source to no more than 80 percent of available PSD increment to allow for future growth.

Source Impact

Since the impacts for 24-hr PM_{10} and 24-hour and annual $PM_{2.5}$ modeled above significant impact levels, a PSD increment analysis for SJE and surrounding sources was required.
Results of the increment modeling are summarized in Table 7 below.

TABLE 7[1]
Increment Analysis

Pollutant	Year	Time-Averaging Period	Maximum Concentration (ug/m^3)	PSD Increment (ug/m^3)	Percent Impact on the PSD Increment	Increment Violation
$PM_{2.5}$	2006-2010	24-hour[2]	3.16	9	35%	NO
$PM_{2.5}$	2006-2010	Annual	0.47	4	12%	NO
PM_{10}	2006-2010	24-hour[2]	3.25	30	11%	NO

[1] Any differences between the maximum concentration numbers in Tables 5 and 6 are due to different sources used for the NAAQS and the increment inventories.
[2] in accordance with the Federal Register dated October 20, 2010; the high 2nd high is used.

The results of the increment analysis show all pollutants for all averaging periods were below 80% of the available increment. No further analysis is required.

Part E – Qualitative Analysis

Additional Impact Analysis

All PSD permit applicants must prepare an additional impact analysis for each pollutant subject to regulation under the Act. This analysis assesses the impacts on growth, soils and vegetation, endangered species, and visibility caused by any increase in emissions of any regulated pollutant from the source. The SJE modeling submittal provided an additional impact analysis performed by Trinity.

Economic Growth

The purpose of the growth analysis is to quantify project associated growth and estimate the air quality impacts from this growth either quantitatively or qualitatively.

Many of the permanent SJE employees will be drawn from the local area. Since the area is predominately rural, it is not expected the growth impacts will cause a violation of the NAAQs or the PSD increment.

Soils and Vegetation Analysis

Soil types included a variety of loamy soils. Due to the agricultural nature of the land, crops in the St. Joseph County area consist mainly of corn and soybeans. (2007 Agricultural Census for St. Joseph County). The maximum modeled concentrations for SJE are well below the threshold limits necessary to have adverse impacts on the surrounding vegetation. Livestock in St. Joseph County consist mainly of hogs, cattle and dairy (2007 Agricultural Census for St. Joseph County) and will not be adversely impacted from the facility. Trees in the area are mainly hardwoods. These are hardy trees and no significant adverse impacts are expected due to modeled concentrations.

Federal and State Endangered Species Analysis

Federal and state endangered species are listed by the U.S. Fish and Wildlife Service; Division of Endangered Species for Indiana, and includes 5 amphibians, 27 birds, 10 fishes, 7 mammals, 15 mollusks, and 15 reptiles. Of the federal and state endangered species on the list, 5 reptiles, 3 mollusks, 1 fish, 1 insect, 18 birds, 3 amphibians and 7 mammals have habitat within St. Joseph County. The mollusks, fish, amphibians, and certain species of birds and mammals are found along rivers and lakes while the other species of birds and mammals are found in forested areas. The facility is not expected to have any additional adverse effects on the habitats of the species than what has already occurred from the industrial, farming, and residential activities in the area.

Federal and state endangered plants are listed by the U.S. Fish and Wildlife Service, Division of Endangered Species for Indiana. At this time 27 state endangered plant species (including the Goose-foot Corn-salad and Running Serviceberry) are found in St. Joseph County. The endangered plants do not thrive in industrialized and residential areas. The facility is not expected to adversely affect any plant on the endangered species list.

Visibility Analysis

Visibility analysis was performed for impacts on local visibility. The VISCREEN model is designed as a screening model to determine the visual impact using parameters from a single source's plume. It is used basically to determine whether or not a plume is visible as an object itself. The visibility impairment analysis considers the impacts that occur within the impact area of the source as defined by the user distances. The user distances are determined by the nearest interstate or airport. EPA has defined

these locations in guidance to the state.

The PM_{10} and NOx emissions limits were used to run a local visibility Level 1 and a Level 2 analysis. VISCREEN Version 1.01 was used to determine if the color difference parameter (Delta-E) or the plume (green) contrast limits were exceeded. The Delta-E was developed to specify the perceived magnitude of color and brightness changes and is used as the primary basis for determining the perceptibility of plume visual impacts. The plume constant can be defined at any wavelength as the relative difference in the intensity (called spectral radiance) between the viewed object and its background. This is used to determine how the human eye responds differently to different wavelengths of light. The Delta-E of 2.0 and the plume contrast of 0.05 were not exceeded at the nearest interstate or airport location.

A Level 1 analysis was performed and showed that there might be a potential adverse visual impact. A Level 2 analysis was performed using the year with the highest percentage of hours that might affect the nearest point of interest, in this case the nearby interstate.

TABLE 8
Level 2 Visibility Analysis

Background	Theta (degrees)	Azimuth (degrees)	Distance (km)	Alpha (degrees)	Delta E Critical	Delta E Plume	Contrast Critical	Contrast Plume
Sky	10	84	5.1	84	5.07	0.859	0.08	0.014
Sky	140	84	5.1	84	2.00	0.366	0.08	-0.010
Terrain	10	84	5.1	84	3.33	5.025*	0.08	0.035
Terrain	140	84	5.1	84	2.00	0.805	0.08	0.018

* This Class II location is above suggested critical value for Class I areas

A forward-scatter analysis is performed on the closest point of the I-90 highway. The range of sun angles over the critical sun elevation (10 degrees) that can occur was calculated using the winter and summer solstices. The 10 degree sun elevation is bounded by the sun angles 67.4 degrees (ENE) at summer solstice and 134.3 degrees (SE) at winter solstice for sunrise conditions. Thus, any observer at any angle between 247.4 degrees (67 + 180), and 314.3 degrees (134.3 + 180) could observe the plume at the critical sun elevation. At the closest location to the facility, I-90 is located at an angle of 344 degrees from the facility. Since I-90 does not fall between the sun angle boundaries, this condition will never occur.

For sunset conditions, the 10 degree sun elevation is bounded by the sun angles 225.7 (Winter Solstice) and 247.4 degrees. (Summer Solstice) Thus any observer at any angle between 45.7 (225.7 - 180) and 67.4 degrees (247.4 - 180) could observe the plume at the critical sun elevation. 344 degrees does not lie within that range, so this condition will not occur.

In a backward scatter analysis, the range of sun angle over which the critical sun elevation (140 degrees) can occur was calculated using the summer solstice since the sun does not reach 140 during the winter solstice. The 140 degree elevation is bounded by the sun angles 93 and 267 degrees. Thus, any observer at any angle between 93 and 267 degrees could observe the source with a sun elevation at 140 degrees. Since I-90 sits at 344 degrees, there will be no adverse impacts on visibility at this location.

Thus, it is concluded that there will be no visibility impacts at the closest location on I-90 from the facility.

The Federal Class I areas include national parks and national wilderness areas and are considered environments for which minimal air quality degradation is allowed. The nearest Class 1 area to SJE is Mammoth Cave National Park which is 490 km from the plant. Pursuant to a new federal

guidance document (Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase 1 Report – Revised November 2010), the SJE facility would not be required to conduct a Class 1 area analysis since the combined emissions of visibility impairing pollutants are less the screening threshold. The visual impact is equal to Q / D, the total emissions divided by distance for sources more than 50 km from a Class 1 area. If the number is less than 10, then a visibility analysis is not required.

The primary visibility impairment pollutants are PM_{10}, SO_2, H_2SO_4, and NO_x. The proposed potential emissions of these pollutants from SJE are Q = 291.7 + 93.0 + 343.5 + 71.9 TPY = 800 TPY. The distance to the nearest Class 1 area is D = 490 km. The source impact is Q / D = 800 / 490 = 1.6. 1.6 is less than 10, so this project will not affect visibility in the nearest Class 1 area.

Additional Analysis Conclusions

Finally, the results of the additional impact analysis conclude the operation of the facility will have no significant impact on economic growth, soils, vegetation, or visibility in the immediate vicinity or on any Class I area.

Part F - Secondary Ozone Formation Analysis

Because of the well established relationship between nitrogen oxides (NO_x), volatile organic compounds (VOCs), and the regional transport formation of ozone, U.S. EPA recently finalized the Cross State Air Pollution Rule (CSAPR) to assist states to meet the ozone NAAQS. This rule included extensive modeling to support the emissions reductions necessary in each state to achieve the ozone NAAQS in the eastern U.S. The source category responsible for these reductions is Electric Generating Units (EGUs).

U.S. EPA used a regional model, Comprehensive Air Quality Model with extensions (CAMx), and the Air Quality Assessment Tool (AQAT) to determine levels of reduction from EGUs necessary to achieve the NAAQS at every site. The documentation includes extensive tables showing impacts at all ozone monitors in the eastern U.S. and emission reduction levels necessary to achieve those results. To examine the possible impact of SJE, results from the modeling U.S. EPA conducted to establish the final 2014 budgets in CSAPR were used for this analysis. The CSAPR website is located at http://www.epa.gov/crossstaterule/techinfo.html.

Information regarding the NO_x emission reductions necessary to achieve the future year modeled design values can be found in the "EmissionsSummaries.xlsx" spreadsheet under the Emissions Inventory Final Rule TSD section at EPA's CSAPR website for technical information http://www.epa.gov/crossstaterule/techinfo.html. The spreadsheet shows the base case annual NO_x emissions for Indiana by 2014 at 431,342 tons and remedy control scenario annual NO_x emissions by 2014 at 424,250 tons. Indiana's total NO_x emission reduction between these scenarios is 7,092 tons. All surrounding states make similar significant reductions. SJE emissions will be 292 tons per year of NOx.

8-Hour Ozone Modeling Results

The nearest ozone monitors to SJE are the Granger, Potato Creek State Park and South Bend ozone monitors in St. Joseph County. Both Granger and South Bend's current design values for 2009-2011 are 64 parts per billion (ppb), and Potato Creek's design value is 61 ppb all well below the 8-hour NAAQS of 75 ppb. The maximum 8-hour ozone modeled concentrations for St. Joseph County are 71.9 ppb for the 2014 base case and 71.6 ppb for the 2014 control scenario. This is a reduction of 0.3 ppb as a result of NO_x emission reductions from CSAPR. In order for this modeled 8-hour concentration reduction from CSAPR to occur, Indiana's 2014 NO_x emissions were reduced by 7,092 tons of NO_x. The St. Joseph County monitoring sites are not necessarily impacted by every EGU in Indiana, but in the surrounding

states, thousands of tons of annual NO_x emission reductions have also occurred by 2014, many of which would impact these sites. Therefore, to estimate the impact of SJE on modeled concentrations, the ratio of SJE NO_x emissions to Indiana's NO_x emission reductions from CSAPR was calculated. This ratio was then compared to the modeled ozone impact from the difference between the CSAPR base case and remedy control modeling results.

1) 292 tons St. Joseph Energy NO_x emissions / 7,092 tons of Indiana's NO_x emissions reduced through CSAPR rulemaking = 0.0412 or 4.12%

2) 0.3 ppb maximum 8-hour modeled CSAPR results for St. Joseph County * 4.12% = 0.01235 ppb of St. Joseph Energy ozone impact

3) 0.01235 ppb of St. Joseph Energy / 71.6 ppb at St. Joseph County ozone monitor from 2014 CSAPR Remedy Maximum modeled results = 0.01725% of the 2014 modeled Remedy results.

Tables are located in CSAPR_AQModeling.pdf, Appendix B, pages B-10 and B-12, for 8-hour ozone design values that show the projected base case 2014 ozone concentrations at surrounding monitoring sites versus control strategy ozone concentrations. 2014 Base represents modeled results taken from the anticipated 2014 emissions and 2014 Remedy represents the 2014 Base emissions with emission reductions from CSAPR factored into the modeling. Table 9 below shows the CSAPR modeling results for nearby ozone monitors and the impact that St. Joseph Energy would have on ozone concentrations in the area.

Table 9
EPA's Cross-State Air Pollution Rule - 8-Hour Ozone Modeling Results

Monitor ID	County	2014 Base (ppb)	2014 Remedy (ppb)	2014 Base-Remedy (ppb)	Anticipated Source Impact (ppb)	Source Impact on 2014 Base-Remedy Results (%)
181411007	St. Joseph	71.9	71.6	0.3	0.0124	0.0173%
181410010	St. Joseph	68.5	68.3	0.2	0.0082	0.0121%
181410015	St. Joseph	69.2	69.0	0.2	0.0082	0.0119%

Summary of Ozone Results

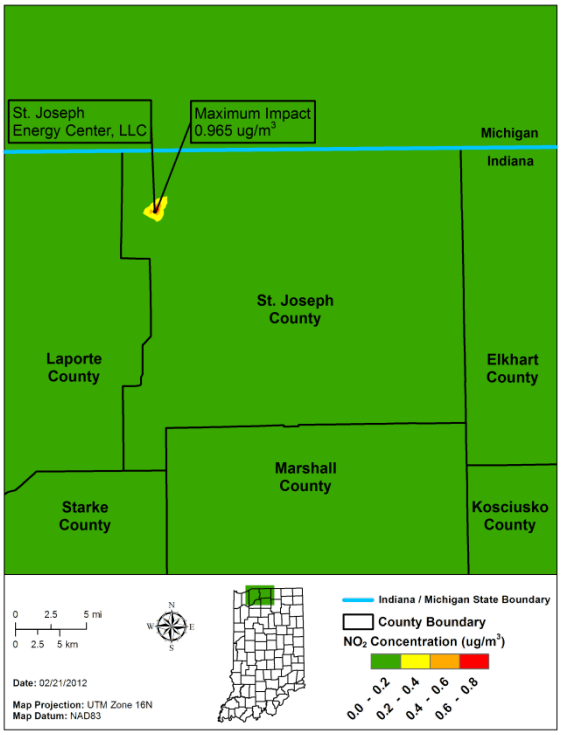
St. Joseph Energy's NO_x emissions were compared with U.S. EPA CSAPR modeling for 8-hour ozone to determine what impacts on ozone may occur as a result of ozone formation. When the St. Joseph Energy emissions were compared with the amount of NOx emission reductions realized from CSAPR and compared with CSAPR modeling results for 8-hour ozone, the impacts from St. Joseph Energy on the three ozone monitors in St. Joseph County are anticipated to be minimal and not have a significant impact on the attainment status of those counties.

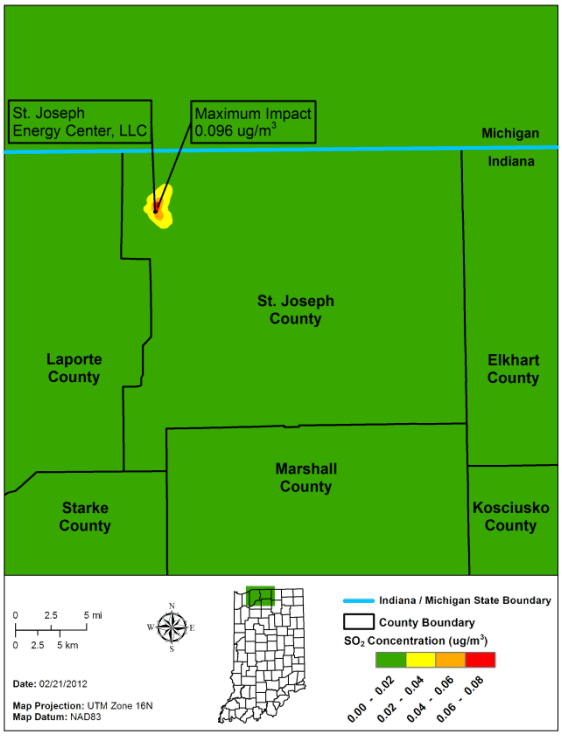
Part G - Secondary $PM_{2.5}$ formation Analysis

In addition to direct emissions of $PM_{2.5}$, other pollutants, chiefly NO_x and SO_2, can lead to formation of $PM_{2.5}$ further downwind. The photochemical reactions that transform these pollutants into particulate nitrates and sulfates, which become the major species of $PM_{2.5}$, take place over hours or days. Potentials to emit after controls for St. Joseph Energy are 292 TPY NO_x and 93 TPY SO_2.

The modeling for SO_2 and annual NO_2 shows that receptor concentrations are below Significant Impact

Levels (SIL) for their respective NAAQS and further diminish within the modeling domain of 50 km



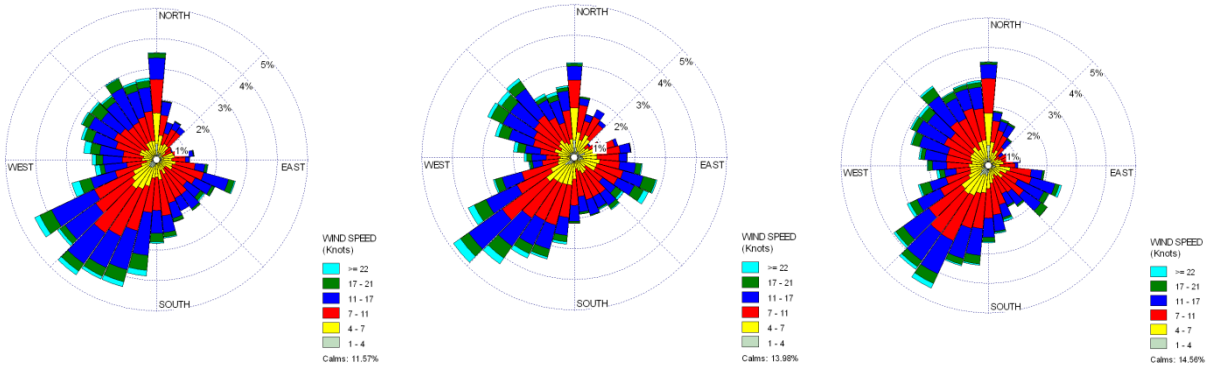


Since the NO_x and SO_2 standards are extremely restrictive, being below the SILs would likely prevent the pollutants from impacting secondary formation significantly enough to result in a violation of the $PM_{2.5}$ standards.

However, it is possible that some transformation into nitrates and sulfates from this source may occur and be transported downwind. No peer-reviewed regulatory model presently exists to examine the photochemical impacts of an individual source of SO_2 or NO_x. All photochemical models are regional scale and a source of this size would not show any measurable impact. Therefore, other available information from emissions inventories, meteorological analyses, and other modeling projects can be used to estimate the impact from this source.

The wind rose shows the general directions that emissions from this source would impact.

South Bend 2008 **South Bend 2009** **South Bend 2010**



Design values from 2008 – 2010 at all $PM_{2.5}$ monitors in Indiana meet the annual and 24-hour NAAQS.

<u>Secondary $PM_{2.5}$ Weight of Evidence Analysis based on EPA's CSAPR Modeling</u>

Because of the well established relationship between NO_x, SO_2, and the regional transport and formation of $PM_{2.5}$, and to assist states to meet the $PM_{2.5}$ NAAQS, U.S. EPA recently finalized the Cross State Air Pollution Rule (CSAPR). This rule included extensive modeling to support the emissions reductions necessary in each state to achieve the $PM_{2.5}$ NAAQS in the eastern U.S. The source category responsible for these reductions is Electric Generating Units (EGUs).

U.S. EPA used a regional model, Comprehensive Air Quality Model with extensions (CAMx), and the Air Quality Assessment Tool (AQAT) to determine levels of reduction from EGUs necessary to achieve the NAAQS at every site. The documentation includes extensive tables showing impacts at all $PM_{2.5}$ monitoring sites in the eastern U.S. and emission reduction levels necessary to achieve those results. To examine the possible impact of SJE, results from the modeling U.S. EPA conducted to establish the final 2014 budgets in CSAPR and were used for this analysis. The CSAPR website is located at http://www.epa.gov/crossstaterule/techinfo.html.

Information regarding SO_2 and NO_x emission reductions necessary to achieve the future year modeled design values can be found in the "EmissionsSummaries.xlsx" spreadsheet under the <u>Emissions Inventory Final Rule TSD</u> section at EPA's CSPAR website for technical information : http://www.epa.gov/crossstaterule/techinfo.html. The spreadsheet shows the base case annual SO_2 and NO_x emissions for Indiana by 2014 and remedy control scenario annual SO_2 and NO_x emissions by 2014. Indiana's total SO_2 and NO_x emission reductions between these scenarios are 539,832 tons. All surrounding states make similar significant reductions.

Table 10
<u>EPA's Cross-State Air Pollution Rule Emission Summary for Indiana</u>

	Pollutant	2014 Base (tons)	2014 Remedy (tons)	EGU Reduction (tons)
Indiana	SO_2	863,923	331,183	532,740
Indiana	NO_x	431,342	424,250	7,092
TOTAL				539,832

Annual $PM_{2.5}$ Modeling Results

The maximum annual $PM_{2.5}$ modeled concentrations for St. Joseph County are 12.23 µg/m^3 for the 2014 base case and 11.37 µg/m^3 for the 2014 remedy (emission control scenario) results. This is a reduction of 0.86 µg/m^3. In order for this modeled annual concentration reduction from CSAPR to occur, Indiana's 2014 SO_2 emissions from EGUs were reduced by 532,740 tons and 2014 NO_x emissions were reduced by 7,092 for a total of 539,832 tons of SO_2 and NO_x. This particular monitoring site is not necessarily impacted by every EGU in Indiana, but in the surrounding states, hundreds of thousands of tons of annual SO_2 emission reductions have also occurred by 2014, many of which would impact this site. Therefore, to estimate the impact of St. Joseph Energy on modeled concentrations, the ratio of St. Joseph Energy SO_2 and NO_x emissions to Indiana's SO_2 and NO_x emission reductions from CSAPR was calculated. This ratio was then compared to the modeled annual $PM_{2.5}$ impact from the difference between the CSAPR base case and remedy control annual $PM_{2.5}$ modeling results.

1) 385 tons St. Joseph Energy SO_2 and NO_x emissions / 539,832 tons of SO_2 and NO_x emissions reduced through CSAPR rulemaking.= 0.000713 or 0.0713%

2) 0.86 µg/m^3 modeled annual $PM_{2.5}$ CSAPR results * 0.0713% St. Joseph SO_2/NOx emission ratio = 0.00061 µg/m^3 of St. Joseph Energy annual $PM_{2.5}$ impact

3) 0.00061 µg/m^3 of St. Joseph Energy/11.37 µg/m^3 of 2014 CSAPR Remedy Maximum modeled results = 0.005% of the 2014 modeled Remedy results.

Tables showing projected base case 2014 $PM_{2.5}$ concentrations at existing monitoring sites versus control strategy $PM_{2.5}$ concentrations are located in CSAPR_AQModeling.pdf, Appendix B, pages B-41 and B-42 for annual design values and pages B-70 to B-72 for 24-hour design values. 2014 Base represents anticipated 2014 emissions, 2014 Remedy represents the 2014 Base emissions with emission reductions from CSAPR factored into the modeling. Table 11 below shows the CSAPR annual PM2.5 modeled concentrations at the three St. Joseph County ozone monitors and SJE anticipated source impacts at each monitor.

Table 11
EPA's Cross-State Air Pollution Rule - Annual $PM_{2.5}$ Modeling Results

Monitor ID	County	2014 Base	2014 Remedy	2014 Base-Remedy (µg/m^3)	Anticipated Source Impact (µg/m^3)	Source Impact of 2014 Remedy (%)
181410014	St. Joseph	12.21	11.29	0.92	0.00066	0.006%
181410008	St. Joseph	12.23	11.37	0.86	0.00061	0.005%
181410004	St. Joseph	11.81	10.90	0.91	0.00065	0.006%

24-Hour $PM_{2.5}$ Modeling Results

The same emissions and impact analysis methodology used for the annual $PM_{2.5}$ impacts was used to determine the 24-hour $PM_{2.5}$ impacts from St. Joseph Energy. The maximum 24-hour modeled concentrations for St. Joseph County are 30.4 µg/m^3 for the 2014 base case and 28.3 µg/m^3 for the 2014 control scenario. This is a reduction of modeled concentration of 2.1 µg/m^3. To estimate the 24-hour impact of St. Joseph Energy on modeled concentrations, the ratio of St. Joseph Energy SO_2 and NO_x emissions and the CSAPR SO_2 and NO_x emission reductions was calculated. This ratio was then compared to the modeled 24-hour $PM_{2.5}$ impact from the difference between the CSAPR base case and

remedy control 24-hour $PM_{2.5}$ modeling results.

1) 385 tons St. Joseph Energy SO_2 and NO_x emissions / 539,832 tons of SO_2 and NO_x emissions reduced through CSAPR rulemaking.= 0.000713 or 0.0713%

2) 2.1 µg/m^3 modeled 24-hour $PM_{2.5}$ CSAPR results * 0.0713% St. Joseph SO_2/NOx emission ratio = 0.0015 µg/m^3 of St. Joseph Energy 24-hour $PM_{2.5}$ impact

3) 0.0015 µg/m^3 of St. Joseph Energy / 28.3 µg/m^3 of the 2014 CSAPR Remedy Maximum modeled 24-hour results = 0.005% of the 2014 modeled Remedy results.

Modeling results below in Table 12 show 2014 Base and Remedy modeled 24-hour concentrations and the anticipated St. Joseph Energy impacts, based on the emissions comparison and estimated impacts.

Table 12
EPA's Cross-State Air Pollution Rule - 24-Hour $PM_{2.5}$ Modeling Results

Monitor ID	County	2014 Base	2014 Remedy	2014 Base-Remedy (µg/m^3)	Anticipated Source Impact (µg/m^3)	Source Impact of 2014 Remedy (%)
181410014	St. Joseph	30.4	28.3	2.1	0.00150	0.005%
181410008	St. Joseph	28.8	28.3	0.5	0.00036	0.001%
181410004	St. Joseph	27.8	27.9	-0.1	-0.00007	0.000%

Summary Annual and 24-Hour $PM_{2.5}$

St. Joseph Energy SO_2 and NO_x emissions were compared with U.S. EPA CSAPR modeling for annual and 24-hour $PM_{2.5}$ to determine what impacts of $PM_{2.5}$ may occur as a result of secondary $PM_{2.5}$ formation. When the St. Joseph Energy emissions were compared with the amount of SO_2 and NO_x emission reductions realized from CSAPR and compared with CSAPR modeling results for annual and 24-hour, the impacts from St. Joseph Energy on nearby $PM_{2.5}$ monitors are anticipated to be minimal and not have an effect on the attainment status of any $PM_{2.5}$ monitors in the area.

Part H - Summary of Air Quality Analysis

Trinity Consultants prepared the modeling portion of the PSD application. St. Joseph County is designated as attainment for all criteria pollutants except the new 1-hour SO_2 standard which is unclassified. PM_{10}, NO_2, SO_2, CO, $PM_{2.5}$, and sulfuric acid mist emission rates associated with the proposed facility exceeded the respective significant emission rates. Modeling results taken from AERMOD model showed that CO, SO_2, PM_{10}, and annual NO_2 impacts were less than significance levels. Refined modeling showed that the NO_2 and $PM_{2.5}$ increments were maintained. NAAQS modeling showed that the 1-hour NO_2, 24-hour and annual $PM_{2.5}$ standards were not exceeded. $PM_{2.5}$ modeling showed some exceedences of the $PM_{2.5}$ 24-hour standard, but SJE contributed 0.0 ug/m^3 to most of them, and did not contribute significantly to any of them. SJE did not trigger the preconstruction monitoring threshold level but can satisfy the preconstruction monitoring requirement since there is existing air quality monitoring data representative of the area. SJE was below the PM_{10} and $PM_{2.5}$ increment modeling. The nearest Class I area is Mammoth Cave National Park in Kentucky 490 kilometers away from the source. An additional impact analysis was required but the operation of the proposed facility will have no significant impact.

Appendix

Table 13
Culpability Analysis For SJE

X	Y	AVERAGE CONC	AVE	RANK	SJE Impact	Total Impact	SJE Cause ?
545550	4616150	29.0	24-HR	1ST	0.0	29.0	No
545650	4616150	28.5	24-HR	1ST	0.0	28.5	No
545550	4616150	27.7	24-HR	2ND	0.0	27.7	No
545450	4616150	27.6	24-HR	1ST	0.0	27.6	No
545650	4616150	26.1	24-HR	2ND	0.0	26.1	No
545550	4616150	26.0	24-HR	3RD	0.0	26.0	No
545550	4616050	24.7	24-HR	1ST	0.0	24.7	No
545650	4616150	24.1	24-HR	3RD	0.0	24.1	No
545350	4616150	22.6	24-HR	1ST	0.0	22.6	No
545650	4616150	22.6	24-HR	4TH	0.0	22.6	No
545450	4616150	22.4	24-HR	2ND	0.0	22.4	No
545650	4616250	22.2	24-HR	1ST	0.0	22.2	No
545550	4616150	21.9	24-HR	4TH	0.0	21.9	No
545550	4616050	21.4	24-HR	2ND	0.0	21.4	No
545350	4616250	21.0	24-HR	1ST	0.0	21.0	No
545450	4616150	20.9	24-HR	3RD	0.0	20.9	No
545550	4616150	20.5	24-HR	5TH	0.0	20.5	No
545550	4616250	20.3	24-HR	1ST	0.0	20.3	No
545650	4616150	20.0	24-HR	5TH	0.0	20.0	No
545250	4616250	19.9	24-HR	1ST	0.0	19.9	No
545450	4616250	19.5	24-HR	1ST	0.0	19.5	No
545650	4616250	19.3	24-HR	2ND	0.0	19.3	No
545550	4616050	19.2	24-HR	3RD	0.0	19.2	No
545650	4616150	18.9	24-HR	6TH	0.0	18.9	No
545450	4616050	18.6	24-HR	1ST	0.0	18.6	No
545550	4616150	18.3	24-HR	6TH	0.0	18.3	No
545450	4616250	18.2	24-HR	2ND	0.0	18.2	No
545550	4616050	18.1	24-HR	4TH	0.0	18.1	No
545450	4616150	17.9	24-HR	4TH	0.0	17.9	No
545650	4616250	17.9	24-HR	3RD	0.0	17.9	No
545250	4616150	17.8	24-HR	1ST	0.0	17.8	No
545350	4616150	17.8	24-HR	2ND	0.0	17.8	No
545350	4616250	17.7	24-HR	2ND	0.0	17.7	No
545650	4616150	17.6	24-HR	7TH	0.0	17.6	No
545150	4616250	17.5	24-HR	1ST	0.0	17.5	No
545550	4616250	17.4	24-HR	2ND	0.0	17.4	No
545550	4616150	17.2	24-HR	7TH	0.0	17.2	No
545550	4616350	17.0	24-HR	1ST	0.0	17.0	No

545650	4616150	16.8	24-HR	8TH	0.0	16.8	No
545450	4616250	16.7	24-HR	3RD	0.0	16.7	No
545450	4616150	16.4	24-HR	5TH	0.0	16.4	No
545550	4616150	16.4	24-HR	8TH	0.0	16.4	No
545250	4616250	16.3	24-HR	2ND	0.0	16.3	No
545550	4616050	16.3	24-HR	5TH	0.0	16.3	No
545450	4616050	16.2	24-HR	2ND	0.0	16.2	No
545550	4616250	16.1	24-HR	3RD	0.0	16.1	No
545150	4616350	16.1	24-HR	1ST	0.0	16.1	No
545650	4616150	16.1	24-HR	9TH	0.0	16.1	No
545350	4616250	16.0	24-HR	3RD	0.0	16.0	No
545550	4616150	16.0	24-HR	9TH	0.0	16.0	No
545350	4616150	15.9	24-HR	3RD	0.0	15.9	No
545650	4616150	15.7	24-HR	10TH	0.0	15.7	No
545450	4616150	15.6	24-HR	6TH	0.0	15.6	No
545250	4616350	15.5	24-HR	1ST	0.0	15.5	No
545550	4616250	15.3	24-HR	4TH	0.0	15.3	No
545450	4616250	15.3	24-HR	4TH	0.0	15.3	No
545650	4616150	15.2	24-HR	11TH	0.0	15.2	No
545550	4616050	15.2	24-HR	6TH	0.0	15.2	No
545050	4616350	15.0	24-HR	1ST	0.0	15.0	No
545350	4616050	15.0	24-HR	1ST	0.0	15.0	No
545250	4616250	14.9	24-HR	3RD	0.0	14.9	No
545350	4616250	14.9	24-HR	4TH	0.0	14.9	No
545450	4616350	14.9	24-HR	1ST	0.0	14.9	No
545550	4616150	14.8	24-HR	10TH	0.0	14.8	No
545650	4616250	14.8	24-HR	4TH	0.1	14.8	No
545450	4616050	14.7	24-HR	3RD	0.0	14.7	No
545650	4616150	14.6	24-HR	12TH	0.0	14.6	No
545050	4616250	14.6	24-HR	1ST	0.0	14.6	No
545550	4616250	14.5	24-HR	5TH	0.0	14.5	No
545450	4616150	14.4	24-HR	7TH	0.0	14.4	No
545150	4616250	14.4	24-HR	2ND	0.0	14.4	No
545450	4616250	14.4	24-HR	5TH	0.0	14.4	No
545550	4616350	14.3	24-HR	2ND	0.0	14.3	No
545350	4616350	14.3	24-HR	1ST	0.0	14.3	No
544950	4616350	14.2	24-HR	1ST	0.0	14.2	No
545150	4616150	14.0	24-HR	1ST	0.0	14.0	No
545650	4616250	14.0	24-HR	5TH	0.0	14.0	No
545550	4616250	14.0	24-HR	6TH	0.0	14.0	No
545550	4616150	13.9	24-HR	11TH	0.0	13.9	No
545450	4616150	13.7	24-HR	8TH	0.0	13.7	No
545350	4616150	13.7	24-HR	4TH	0.0	13.7	No

545350	4616050	13.6	24-HR	2ND	0.0	13.6	No
545450	4616350	13.6	24-HR	2ND	0.0	13.6	No
545650	4616150	13.5	24-HR	13TH	0.0	13.5	No
545550	4616050	13.5	24-HR	7TH	0.0	13.5	No
545250	4616250	13.5	24-HR	4TH	0.0	13.5	No
545550	4616150	13.4	24-HR	12TH	0.0	13.4	No
545350	4616250	13.4	24-HR	5TH	0.0	13.4	No
545250	4616150	13.3	24-HR	2ND	0.0	13.3	No
545650	4616150	13.2	24-HR	14TH	0.0	13.2	No
545650	4616250	13.2	24-HR	6TH	0.0	13.2	No
545550	4616250	13.2	24-HR	7TH	0.0	13.2	No
545450	4616150	13.0	24-HR	9TH	0.0	13.0	No
545650	4616150	13.0	24-HR	15TH	0.0	13.0	No
545350	4616150	12.9	24-HR	5TH	0.0	12.9	No
545650	4616250	12.9	24-HR	7TH	0.0	12.9	No
545550	4616350	12.9	24-HR	3RD	0.0	12.9	No
545450	4616350	12.9	24-HR	3RD	0.0	12.9	No
544950	4616450	12.8	24-HR	1ST	0.0	12.8	No
545450	4616250	12.8	24-HR	6TH	0.0	12.8	No
545350	4616350	12.8	24-HR	2ND	0.0	12.8	No
545550	4616150	12.7	24-HR	13TH	0.0	12.7	No
545250	4616350	12.7	24-HR	2ND	0.0	12.7	No
545050	4616450	12.7	24-HR	1ST	0.0	12.7	No
545450	4616150	12.7	24-HR	10TH	0.0	12.7	No
545250	4616050	12.6	24-HR	1ST	0.0	12.6	No
544850	4616350	12.5	24-HR	1ST	0.0	12.5	No
545550	4616050	12.5	24-HR	8TH	0.0	12.5	No
545150	4616250	12.5	24-HR	3RD	0.0	12.5	No
544950	4616250	12.5	24-HR	1ST	0.0	12.5	No
545550	4616250	12.5	24-HR	8TH	0.0	12.5	No
545650	4616250	12.4	24-HR	8TH	0.0	12.4	No
545650	4616150	12.4	24-HR	16TH	0.0	12.4	No
545450	4616050	12.4	24-HR	4TH	0.0	12.4	No
544850	4616450	12.3	24-HR	1ST	0.0	12.3	No
545250	4616150	12.3	24-HR	3RD	0.0	12.3	No
545550	4616150	12.3	24-HR	14TH	0.0	12.3	No
545050	4616250	12.2	24-HR	2ND	0.0	12.2	No
545150	4616350	12.2	24-HR	2ND	0.0	12.2	No
545450	4616150	12.2	24-HR	11TH	0.0	12.2	No
545650	4616150	12.2	24-HR	17TH	0.0	12.2	No
545250	4616250	12.1	24-HR	5TH	0.0	12.1	No
545350	4616250	12.1	24-HR	6TH	0.0	12.1	No
545250	4616350	12.0	24-HR	3RD	0.0	12.0	No

545350	4616050	12.0	24-HR	3RD	0.0	12.0	No
545450	4616250	11.9	24-HR	7TH	0.0	11.9	No
545150	4616250	11.9	24-HR	4TH	0.0	11.9	No
545450	4616050	11.9	24-HR	5TH	0.0	11.9	No
545350	4616150	11.8	24-HR	6TH	0.0	11.8	No
545350	4616350	11.8	24-HR	3RD	0.0	11.8	No
545450	4616350	11.7	24-HR	4TH	0.0	11.7	No
545650	4616150	11.7	24-HR	18TH	0.0	11.7	No
545550	4616350	11.6	24-HR	4TH	0.0	11.6	No
544750	4616450	11.6	24-HR	1ST	0.0	11.6	No
545150	4616450	11.6	24-HR	1ST	0.0	11.6	No
545650	4616250	11.6	24-HR	9TH	0.0	11.6	No
545350	4616450	11.5	24-HR	1ST	0.0	11.5	No
545450	4616150	11.5	24-HR	12TH	0.0	11.5	No
545550	4616150	11.5	24-HR	15TH	0.0	11.5	No
545450	4616250	11.4	24-HR	8TH	0.0	11.4	No
545550	4616050	11.4	24-HR	9TH	0.0	11.4	No
545350	4616150	11.4	24-HR	7TH	0.0	11.4	No
545450	4616050	11.3	24-HR	6TH	0.0	11.3	No
545350	4616250	11.3	24-HR	7TH	0.0	11.3	No
545550	4616250	11.3	24-HR	9TH	0.0	11.3	No
545550	4616150	11.3	24-HR	16TH	0.0	11.3	No
545050	4616350	11.2	24-HR	2ND	0.0	11.2	No
545250	4616450	11.2	24-HR	1ST	0.0	11.2	No
545150	4616350	11.2	24-HR	3RD	0.0	11.2	No
545350	4616350	11.2	24-HR	4TH	0.0	11.2	No
545250	4616050	11.2	24-HR	2ND	0.0	11.2	No
545050	4616150	11.1	24-HR	1ST	0.0	11.1	No
545650	4616250	11.0	24-HR	10TH	0.0	11.0	No
545550	4616150	11.0	24-HR	17TH	0.0	11.0	No
545050	4616250	11.0	24-HR	3RD	0.0	11.0	No
545350	4616250	10.9	24-HR	8TH	0.0	10.9	No
545550	4616250	10.9	24-HR	10TH	0.0	10.9	No
545450	4616250	10.9	24-HR	9TH	0.0	10.9	No
545250	4616150	10.9	24-HR	4TH	0.0	10.9	No
545450	4616050	10.9	24-HR	7TH	0.0	10.9	No
545550	4616350	10.9	24-HR	5TH	0.0	10.9	No
545250	4616250	10.9	24-HR	6TH	0.0	10.9	No
544650	4616450	10.9	24-HR	1ST	0.0	10.9	No
544950	4615850	10.9	24-HR	1ST	0.0	10.9	No
545350	4616150	10.9	24-HR	8TH	0.0	10.9	No
545450	4616350	10.8	24-HR	5TH	0.0	10.8	No
545650	4616150	10.8	24-HR	19TH	0.0	10.8	No

545350	4616450	10.8	24-HR	2ND	0.0	10.8	No
545550	4616150	10.8	24-HR	18TH	0.0	10.8	No
545550	4616050	10.7	24-HR	10TH	0.0	10.7	No
545150	4616150	10.7	24-HR	2ND	0.0	10.7	No
544850	4616550	10.7	24-HR	1ST	0.0	10.7	No
544750	4616550	10.7	24-HR	1ST	0.0	10.7	No
544750	4616350	10.7	24-HR	1ST	0.0	10.7	No
545050	4616350	10.7	24-HR	3RD	0.0	10.7	No
544950	4616350	10.7	24-HR	2ND	0.0	10.7	No
545350	4616350	10.6	24-HR	5TH	0.0	10.6	No
545650	4616250	10.6	24-HR	11TH	0.0	10.6	No
544850	4616250	10.6	24-HR	1ST	0.0	10.6	No
545450	4616150	10.6	24-HR	13TH	0.0	10.6	No
545350	4616150	10.6	24-HR	9TH	0.0	10.6	No
545150	4616050	10.6	24-HR	1ST	0.0	10.6	No
545150	4616250	10.5	24-HR	5TH	0.0	10.5	No
545650	4616150	10.5	24-HR	20TH	0.0	10.5	No
545550	4616250	10.5	24-HR	11TH	0.0	10.5	No
544950	4616550	10.5	24-HR	1ST	0.0	10.5	No
545150	4616350	10.5	24-HR	4TH	0.0	10.5	No
545550	4616150	10.5	24-HR	19TH	0.0	10.5	No
544950	4615750	10.4	24-HR	1ST	0.0	10.4	No
545250	4616250	10.4	24-HR	7TH	0.0	10.4	No
545350	4616250	10.4	24-HR	9TH	0.0	10.4	No
545650	4616250	10.3	24-HR	12TH	0.0	10.3	No
545350	4616050	10.3	24-HR	4TH	0.0	10.3	No
544650	4616550	10.3	24-HR	1ST	0.0	10.3	No
545550	4616050	10.3	24-HR	11TH	0.0	10.3	No
545250	4616350	10.3	24-HR	4TH	0.0	10.3	No
545450	4616150	10.3	24-HR	14TH	0.0	10.3	No
544950	4615950	10.3	24-HR	1ST	0.0	10.3	No
545450	4616250	10.3	24-HR	10TH	0.0	10.3	No
545350	4616150	10.3	24-HR	10TH	0.0	10.3	No
545650	4616150	10.3	24-HR	21ST	0.0	10.3	No
545450	4616350	10.1	24-HR	6TH	0.0	10.1	No
544950	4616350	10.1	24-HR	3RD	0.0	10.1	No
545550	4616350	10.1	24-HR	6TH	0.0	10.1	No
545650	4616250	10.0	24-HR	13TH	0.1	10.0	No
545550	4616050	10.0	24-HR	12TH	0.0	10.0	No
545250	4616150	10.0	24-HR	5TH	0.0	10.0	No
545650	4616150	10.0	24-HR	22ND	0.0	10.0	No
545350	4616450	10.0	24-HR	3RD	0.0	10.0	No
544950	4616250	10.0	24-HR	2ND	0.0	10.0	No

545450	4616250	9.9	24-HR	11TH	0.0	9.9	No
545350	4616250	9.9	24-HR	10TH	0.0	9.9	No
545350	4616150	9.8	24-HR	11TH	0.0	9.8	No
545550	4616050	9.8	24-HR	13TH	0.0	9.8	No
545350	4616350	9.8	24-HR	6TH	0.0	9.8	No
544850	4615750	9.8	24-HR	1ST	0.0	9.8	No
544550	4616550	9.8	24-HR	1ST	0.0	9.8	No
545650	4616250	9.8	24-HR	14TH	0.0	9.8	No
545250	4616350	9.8	24-HR	5TH	0.0	9.8	No
545450	4616250	9.8	24-HR	12TH	0.0	9.8	No
544550	4616450	9.8	24-HR	1ST	0.0	9.8	No
545250	4616250	9.7	24-HR	8TH	0.0	9.7	No
545650	4616150	9.7	24-HR	23RD	0.0	9.7	No
545050	4616350	9.7	24-HR	4TH	0.0	9.7	No
545450	4616150	9.7	24-HR	15TH	0.0	9.7	No
545250	4616050	9.7	24-HR	3RD	0.0	9.7	No
545550	4616250	9.7	24-HR	12TH	0.0	9.7	No
545550	4616150	9.7	24-HR	20TH	0.0	9.7	No
545250	4616450	9.7	24-HR	2ND	0.0	9.7	No
544850	4615850	9.6	24-HR	1ST	0.0	9.6	No
544850	4616350	9.6	24-HR	2ND	0.0	9.6	No
545150	4616450	9.6	24-HR	2ND	0.0	9.6	No
545150	4616350	9.5	24-HR	5TH	0.0	9.5	No
545450	4616350	9.5	24-HR	7TH	0.0	9.5	No
545550	4616350	9.5	24-HR	7TH	0.0	9.5	No
545350	4616250	9.5	24-HR	11TH	0.0	9.5	No
545150	4616150	9.5	24-HR	3RD	0.0	9.5	No
545550	4616250	9.5	24-HR	13TH	0.0	9.5	No
545450	4616250	9.5	24-HR	13TH	0.0	9.5	No
544950	4616450	9.5	24-HR	2ND	0.0	9.5	No
545150	4616250	9.4	24-HR	6TH	0.0	9.4	No
545350	4616050	9.4	24-HR	5TH	0.0	9.4	No
545650	4616150	9.4	24-HR	24TH	0.0	9.4	No
544650	4616350	9.4	24-HR	1ST	0.0	9.4	No
545050	4616450	9.4	24-HR	2ND	0.0	9.4	No
545150	4616050	9.4	24-HR	2ND	0.0	9.4	No
545450	4616150	9.4	24-HR	16TH	0.0	9.4	No
544850	4615950	9.3	24-HR	1ST	0.0	9.3	No
544450	4616550	9.3	24-HR	1ST	0.0	9.3	No
545350	4616450	9.3	24-HR	4TH	0.0	9.3	No
545350	4616150	9.3	24-HR	12TH	0.0	9.3	No
544550	4616650	9.3	24-HR	1ST	0.0	9.3	No
545050	4616250	9.3	24-HR	4TH	0.0	9.3	No

545250	4616150	9.3	24-HR	6TH	0.0	9.3	No
545250	4616250	9.2	24-HR	9TH	0.0	9.2	No
545050	4616050	9.2	24-HR	1ST	0.0	9.2	No
545250	4616450	9.2	24-HR	3RD	0.0	9.2	No
544950	4616350	9.2	24-HR	4TH	0.0	9.2	No
545050	4616550	9.2	24-HR	1ST	0.0	9.2	No
545450	4616250	9.2	24-HR	14TH	0.0	9.2	No
545350	4616250	9.2	24-HR	12TH	0.0	9.2	No
545650	4616150	9.2	24-HR	25TH	0.0	9.2	No
544750	4615750	9.2	24-HR	1ST	0.0	9.2	No
545250	4616150	9.1	24-HR	7TH	0.0	9.1	No
545550	4616050	9.1	24-HR	14TH	0.0	9.1	No
545550	4616150	9.1	24-HR	21ST	0.0	9.1	No
545350	4616150	9.1	24-HR	13TH	0.0	9.1	No
545350	4616350	9.0	24-HR	7TH	0.0	9.0	No
544950	4616250	9.0	24-HR	3RD	0.0	9.0	No
545550	4616250	9.0	24-HR	14TH	0.0	9.0	No
545550	4616350	9.0	24-HR	8TH	0.0	9.0	No
545450	4616150	9.0	24-HR	17TH	0.0	9.0	No
544450	4616650	8.9	24-HR	1ST	0.0	8.9	No
545050	4616150	8.9	24-HR	2ND	0.0	8.9	No
545050	4616250	8.9	24-HR	5TH	0.0	8.9	No
544750	4616250	8.9	24-HR	1ST	0.0	8.9	No
545050	4616450	8.9	24-HR	3RD	0.0	8.9	No
544950	4616150	8.9	24-HR	1ST	0.0	8.9	No
545650	4616250	8.9	24-HR	15TH	0.0	8.9	No
545250	4616450	8.9	24-HR	4TH	0.0	8.9	No
544850	4616350	8.9	24-HR	3RD	0.0	8.9	No
545150	4616150	8.9	24-HR	4TH	0.0	8.9	No
544850	4616450	8.8	24-HR	2ND	0.0	8.8	No
545450	4616050	8.8	24-HR	8TH	0.0	8.8	No
544750	4616450	8.8	24-HR	2ND	0.0	8.8	No
544850	4615650	8.8	24-HR	1ST	0.0	8.8	No
544750	4615850	8.8	24-HR	1ST	0.0	8.8	No
545050	4616350	8.8	24-HR	5TH	0.0	8.8	No
545350	4616250	8.8	24-HR	13TH	0.0	8.8	No
545450	4616350	8.8	24-HR	8TH	0.0	8.8	No
545450	4616250	8.8	24-HR	15TH	0.0	8.8	No
545350	4616050	8.8	24-HR	6TH	0.0	8.8	No
545550	4616250	8.7	24-HR	15TH	0.0	8.7	No
544750	4616350	8.7	24-HR	2ND	0.0	8.7	No
545150	4616450	8.7	24-HR	3RD	0.0	8.7	No
545350	4616450	8.7	24-HR	5TH	0.0	8.7	No

545650	4616150	8.7	24-HR	26TH	0.0	8.7	No
544350	4616550	8.7	24-HR	1ST	0.0	8.7	No
545650	4616250	8.7	24-HR	16TH	0.0	8.7	No
545150	4616350	8.7	24-HR	6TH	0.0	8.7	No
545150	4616250	8.7	24-HR	7TH	0.0	8.7	No
545350	4616150	8.7	24-HR	14TH	0.0	8.7	No
545550	4616350	8.6	24-HR	9TH	0.0	8.6	No
544450	4616450	8.6	24-HR	1ST	0.0	8.6	No
544350	4616650	8.6	24-HR	1ST	0.0	8.6	No
544750	4615650	8.6	24-HR	1ST	0.0	8.6	No
545450	4616150	8.6	24-HR	18TH	0.0	8.6	No
545250	4616350	8.5	24-HR	6TH	0.0	8.5	No
545250	4616050	8.5	24-HR	4TH	0.0	8.5	No
545350	4616350	8.5	24-HR	8TH	0.0	8.5	No
545650	4616150	8.5	24-HR	27TH	0.0	8.5	No
544550	4616350	8.5	24-HR	1ST	0.0	8.5	No
544850	4616350	8.5	24-HR	4TH	0.0	8.5	No
545550	4616150	8.5	24-HR	22ND	0.0	8.5	No
544750	4615950	8.5	24-HR	1ST	0.0	8.5	No
542050	4616550	8.5	24-HR	1ST	0.6	8.5	No
545550	4616250	8.5	24-HR	16TH	0.0	8.5	No
544950	4615750	8.5	24-HR	2ND	0.1	8.5	No
545250	4616250	8.5	24-HR	10TH	0.0	8.5	No
544850	4616450	8.5	24-HR	3RD	0.0	8.5	No
545550	4616050	8.5	24-HR	15TH	0.0	8.5	No
544650	4615750	8.5	24-HR	1ST	0.0	8.5	No
544950	4616350	8.4	24-HR	5TH	0.0	8.4	No
545150	4616250	8.4	24-HR	8TH	0.0	8.4	No
545350	4616050	8.4	24-HR	7TH	0.0	8.4	No
541950	4616650	8.4	24-HR	1ST	0.7	8.4	No
544950	4616450	8.4	24-HR	3RD	0.0	8.4	No
545250	4616150	8.4	24-HR	8TH	0.0	8.4	No
545250	4616450	8.4	24-HR	5TH	0.0	8.4	No
545450	4616050	8.4	24-HR	9TH	0.0	8.4	No
544950	4615850	8.4	24-HR	2ND	0.0	8.4	No
545150	4616450	8.4	24-HR	4TH	0.0	8.4	No
545550	4616350	8.3	24-HR	10TH	0.0	8.3	No
545450	4616150	8.3	24-HR	19TH	0.0	8.3	No
545550	4616050	8.3	24-HR	16TH	0.0	8.3	No
545450	4616350	8.3	24-HR	9TH	0.0	8.3	No
545350	4616250	8.3	24-HR	14TH	0.0	8.3	No
544850	4616250	8.3	24-HR	2ND	0.0	8.3	No
545150	4616350	8.3	24-HR	7TH	0.0	8.3	No

545250	4616350	8.2	24-HR	7TH	0.0	8.2	No
544950	4616050	8.2	24-HR	1ST	0.0	8.2	No
545550	4616150	8.2	24-HR	23RD	0.0	8.2	No
542050	4616650	8.2	24-HR	1ST	0.6	8.2	No
541950	4616550	8.2	24-HR	1ST	0.7	8.2	No
544950	4615950	8.2	24-HR	2ND	0.0	8.2	No
545550	4616050	8.2	24-HR	17TH	0.0	8.2	No
545450	4616250	8.2	24-HR	16TH	0.0	8.2	No
545650	4616250	8.2	24-HR	17TH	0.0	8.2	No
544350	4616750	8.1	24-HR	1ST	0.0	8.1	No
545150	4616350	8.1	24-HR	8TH	0.0	8.1	No
545650	4616150	8.1	24-HR	28TH	0.0	8.1	No
545050	4616050	8.1	24-HR	2ND	0.0	8.1	No
544650	4616450	8.1	24-HR	2ND	0.0	8.1	No
545450	4616350	8.1	24-HR	10TH	0.0	8.1	No
545150	4616150	8.1	24-HR	5TH	0.0	8.1	No
544650	4615850	8.1	24-HR	1ST	0.0	8.1	No
545550	4616250	8.1	24-HR	17TH	0.0	8.1	No
545350	4616450	8.1	24-HR	6TH	0.0	8.1	No
545550	4616150	8.1	24-HR	24TH	0.0	8.1	No
544250	4616650	8.1	24-HR	1ST	0.0	8.1	No
545550	4616350	8.1	24-HR	11TH	0.0	8.1	No
541850	4616650	8.1	24-HR	1ST	0.6	8.1	No
545350	4616250	8.1	24-HR	15TH	0.0	8.1	No
544850	4615750	8.1	24-HR	2ND	0.1	8.1	No
545250	4616150	8.0	24-HR	9TH	0.0	8.0	No
545650	4616250	8.0	24-HR	18TH	0.0	8.0	No
542050	4616750	8.0	24-HR	1ST	0.5	8.0	No
545150	4616050	8.0	24-HR	3RD	0.0	8.0	No
544750	4616350	8.0	24-HR	3RD	0.0	8.0	No
545050	4616350	8.0	24-HR	6TH	0.0	8.0	No
545450	4616250	8.0	24-HR	17TH	0.0	8.0	No
544650	4615650	8.0	24-HR	1ST	0.0	8.0	No
545350	4616150	8.0	24-HR	15TH	0.0	8.0	No
545250	4616350	8.0	24-HR	8TH	0.0	8.0	No
544350	4616850	8.0	24-HR	1ST	0.0	8.0	No
545350	4616350	8.0	24-HR	9TH	0.0	8.0	No
545450	4616150	8.0	24-HR	20TH	0.0	8.0	No
545250	4616250	8.0	24-HR	11TH	0.0	8.0	No
545650	4616150	8.0	24-HR	29TH	0.0	8.0	No
545050	4616150	7.9	24-HR	3RD	0.0	7.9	No
545450	4616250	7.9	24-HR	18TH	0.0	7.9	No
545550	4616250	7.9	24-HR	18TH	0.0	7.9	No

544750	4616450	7.9	24-HR	3RD	0.0	7.9	No
545450	4616050	7.9	24-HR	10TH	0.0	7.9	No
544650	4616250	7.9	24-HR	1ST	0.0	7.9	No
544250	4616550	7.9	24-HR	1ST	0.0	7.9	No
545450	4616150	7.9	24-HR	21ST	0.0	7.9	No
544650	4615350	7.9	24-HR	1ST	0.0	7.9	No
545350	4616250	7.9	24-HR	16TH	0.0	7.9	No
545150	4616450	7.9	24-HR	5TH	0.0	7.9	No
544250	4616750	7.8	24-HR	1ST	0.0	7.8	No
544850	4616350	7.8	24-HR	5TH	0.0	7.8	No
545450	4616350	7.8	24-HR	11TH	0.0	7.8	No
542150	4616550	7.8	24-HR	1ST	0.7	7.8	No
545250	4616250	7.8	24-HR	12TH	0.0	7.8	No
541850	4616550	7.8	24-HR	1ST	0.8	7.8	No
545250	4616150	7.8	24-HR	10TH	0.0	7.8	No
544450	4616350	7.8	24-HR	1ST	0.1	7.8	No
545250	4616050	7.8	24-HR	5TH	0.0	7.8	No
544350	4616450	7.8	24-HR	1ST	0.0	7.8	No
544550	4615750	7.8	24-HR	1ST	0.0	7.8	No
545550	4616150	7.8	24-HR	25TH	0.0	7.8	No
545150	4616350	7.8	24-HR	9TH	0.0	7.8	No
544950	4616250	7.8	24-HR	4TH	0.0	7.8	No
545550	4616050	7.8	24-HR	18TH	0.0	7.8	No
544750	4615350	7.8	24-HR	1ST	0.1	7.8	No
544650	4615950	7.8	24-HR	1ST	0.0	7.8	No
544850	4616450	7.7	24-HR	4TH	0.0	7.7	No
545450	4616250	7.7	24-HR	19TH	0.0	7.7	No
545050	4616250	7.7	24-HR	6TH	0.0	7.7	No
544550	4615850	7.7	24-HR	1ST	0.0	7.7	No
544650	4616350	7.7	24-HR	2ND	0.0	7.7	No
544450	4616850	7.7	24-HR	1ST	0.0	7.7	No
545050	4616350	7.7	24-HR	7TH	0.0	7.7	No
544850	4615850	7.7	24-HR	2ND	0.0	7.7	No
545650	4616250	7.7	24-HR	19TH	0.0	7.7	No
544950	4616150	7.7	24-HR	2ND	0.0	7.7	No
541750	4616650	7.7	24-HR	1ST	0.6	7.7	No
544250	4616850	7.7	24-HR	1ST	0.0	7.7	No
544450	4615250	7.7	24-HR	1ST	0.1	7.7	No
545550	4616250	7.7	24-HR	19TH	0.0	7.7	No
545250	4616250	7.7	24-HR	13TH	0.0	7.7	No
545650	4616150	7.6	24-HR	30TH	0.0	7.6	No
545250	4616350	7.6	24-HR	9TH	0.0	7.6	No
545050	4616450	7.6	24-HR	4TH	0.0	7.6	No

544750	4616350	7.6	24-HR	4TH	0.1	7.6	No
545250	4616150	7.6	24-HR	11TH	0.0	7.6	No
544150	4616650	7.6	24-HR	1ST	0.0	7.6	No
544150	4616750	7.6	24-HR	1ST	0.0	7.6	No
544950	4616350	7.6	24-HR	6TH	0.0	7.6	No
545250	4616450	7.6	24-HR	6TH	0.0	7.6	No
544850	4615650	7.6	24-HR	2ND	0.1	7.6	No
544950	4616450	7.6	24-HR	4TH	0.0	7.6	No
544850	4616550	7.6	24-HR	2ND	0.0	7.6	No
545350	4616150	7.6	24-HR	16TH	0.0	7.6	No
545550	4616350	7.6	24-HR	12TH	0.0	7.6	No
545150	4616250	7.6	24-HR	9TH	0.0	7.6	No
545050	4616550	7.6	24-HR	2ND	0.0	7.6	No
544550	4615250	7.6	24-HR	1ST	0.1	7.6	No
542150	4616450	7.6	24-HR	1ST	0.6	7.6	No
544750	4615750	7.6	24-HR	2ND	0.1	7.6	No
544750	4615450	7.6	24-HR	1ST	0.0	7.6	No
545550	4616050	7.6	24-HR	19TH	0.0	7.6	No
545550	4616150	7.6	24-HR	26TH	0.0	7.6	No
545450	4616250	7.6	24-HR	20TH	0.0	7.6	No
545350	4616450	7.5	24-HR	7TH	0.0	7.5	No
545450	4616050	7.5	24-HR	11TH	0.0	7.5	No
545450	4616150	7.5	24-HR	22ND	0.0	7.5	No
545050	4616250	7.5	24-HR	7TH	0.0	7.5	No
544950	4616550	7.5	24-HR	2ND	0.0	7.5	No
545350	4616250	7.5	24-HR	17TH	0.0	7.5	No
541750	4616550	7.5	24-HR	1ST	0.7	7.5	No
542150	4616650	7.5	24-HR	1ST	0.7	7.5	No
544850	4616150	7.5	24-HR	1ST	0.0	7.5	No
545650	4616150	7.5	24-HR	31ST	0.0	7.5	No
545550	4616250	7.5	24-HR	20TH	0.0	7.5	No
545250	4616350	7.5	24-HR	10TH	0.0	7.5	No
545150	4616250	7.5	24-HR	10TH	0.0	7.5	No
545450	4616350	7.5	24-HR	12TH	0.0	7.5	No
545350	4616350	7.5	24-HR	10TH	0.0	7.5	No
544850	4615950	7.5	24-HR	2ND	0.0	7.5	No
545350	4616050	7.4	24-HR	8TH	0.0	7.4	No
544850	4616050	7.4	24-HR	1ST	0.0	7.4	No
545450	4616150	7.4	24-HR	23RD	0.0	7.4	No
544750	4615650	7.4	24-HR	2ND	0.2	7.4	No
544550	4615350	7.4	24-HR	1ST	0.0	7.4	No
545650	4616250	7.4	24-HR	20TH	0.0	7.4	No
545550	4616350	7.4	24-HR	13TH	0.0	7.4	No

545550	4616050	7.4	24-HR	20TH	0.0	7.4	No
544250	4615150	7.4	24-HR	1ST	0.0	7.4	No
544550	4616450	7.4	24-HR	2ND	0.0	7.4	No
545150	4616150	7.4	24-HR	6TH	0.0	7.4	No
544850	4616250	7.4	24-HR	3RD	0.0	7.4	No
544550	4615650	7.4	24-HR	1ST	0.0	7.4	No
544750	4616550	7.4	24-HR	2ND	0.0	7.4	No
544450	4615850	7.4	24-HR	1ST	0.0	7.4	No
544350	4615150	7.4	24-HR	1ST	0.1	7.4	No
544850	4615550	7.3	24-HR	1ST	0.0	7.3	No
544350	4616350	7.3	24-HR	1ST	0.1	7.3	No
545050	4616350	7.3	24-HR	8TH	0.0	7.3	No
544750	4616250	7.3	24-HR	2ND	0.0	7.3	No
544650	4616550	7.3	24-HR	2ND	0.0	7.3	No
544050	4615050	7.3	24-HR	1ST	0.0	7.3	No
545450	4616250	7.3	24-HR	21ST	0.0	7.3	No
544150	4616950	7.3	24-HR	1ST	0.0	7.3	No
545250	4616250	7.3	24-HR	14TH	0.0	7.3	No
545250	4616350	7.3	24-HR	11TH	0.0	7.3	No
545550	4616150	7.3	24-HR	27TH	0.0	7.3	No
545250	4616150	7.3	24-HR	12TH	0.0	7.3	No
541950	4616850	7.3	24-HR	1ST	0.4	7.3	No
545550	4616250	7.3	24-HR	21ST	0.0	7.3	No
541950	4616450	7.3	24-HR	1ST	0.5	7.3	No
544550	4616550	7.3	24-HR	2ND	0.0	7.3	No
541650	4616650	7.3	24-HR	1ST	0.6	7.3	No
544850	4616450	7.3	24-HR	5TH	0.0	7.3	No
545350	4616150	7.3	24-HR	17TH	0.0	7.3	No
544350	4615250	7.3	24-HR	1ST	0.0	7.3	No
544150	4616850	7.3	24-HR	1ST	0.0	7.3	No
545650	4616150	7.3	24-HR	32ND	0.0	7.3	No
544650	4616450	7.3	24-HR	3RD	0.0	7.3	No
544250	4616950	7.2	24-HR	1ST	0.0	7.2	No
544150	4615050	7.2	24-HR	1ST	0.0	7.2	No
545550	4616350	7.2	24-HR	14TH	0.0	7.2	No
545350	4616250	7.2	24-HR	18TH	0.0	7.2	No
544750	4616450	7.2	24-HR	4TH	0.0	7.2	No
544350	4615650	7.2	24-HR	1ST	0.1	7.2	No
544950	4615950	7.2	24-HR	3RD	0.0	7.2	No
543850	4614950	7.2	24-HR	1ST	0.0	7.2	No
545050	4616550	7.2	24-HR	3RD	0.0	7.2	No
544950	4615750	7.2	24-HR	3RD	0.0	7.2	No
545650	4616250	7.2	24-HR	21ST	0.0	7.2	No

545150	4616250	7.2	24-HR	11TH	0.0	7.2	No
541850	4616750	7.2	24-HR	1ST	0.5	7.2	No
543950	4614950	7.2	24-HR	1ST	0.0	7.2	No
545150	4616350	7.2	24-HR	10TH	0.1	7.2	No
544950	4616050	7.2	24-HR	2ND	0.0	7.2	No
544150	4616550	7.2	24-HR	1ST	0.0	7.2	No
545150	4616050	7.2	24-HR	4TH	0.0	7.2	No
544150	4615150	7.2	24-HR	1ST	0.0	7.2	No
544550	4616250	7.1	24-HR	1ST	0.0	7.1	No
545550	4616250	7.1	24-HR	22ND	0.0	7.1	No
545350	4616250	7.1	24-HR	19TH	0.0	7.1	No
541650	4616550	7.1	24-HR	1ST	0.7	7.1	No
544250	4615650	7.1	24-HR	1ST	0.1	7.1	No
545150	4616450	7.1	24-HR	6TH	0.0	7.1	No
545550	4616150	7.1	24-HR	28TH	0.0	7.1	No
544450	4615750	7.1	24-HR	1ST	0.0	7.1	No
545250	4616250	7.1	24-HR	15TH	0.0	7.1	No
544250	4616450	7.1	24-HR	1ST	0.1	7.1	No
541850	4616450	7.1	24-HR	1ST	0.4	7.1	No
544050	4616750	7.1	24-HR	1ST	0.0	7.1	No
544550	4615950	7.1	24-HR	1ST	0.0	7.1	No
544450	4615650	7.1	24-HR	1ST	0.1	7.1	No
544650	4615750	7.1	24-HR	2ND	0.1	7.1	No
544050	4616650	7.1	24-HR	1ST	0.0	7.1	No
544950	4616250	7.1	24-HR	5TH	0.0	7.1	No
543650	4614850	7.1	24-HR	1ST	0.0	7.1	No
545150	4616150	7.1	24-HR	7TH	0.0	7.1	No
545450	4616350	7.1	24-HR	13TH	0.0	7.1	No
545350	4616350	7.0	24-HR	11TH	0.0	7.0	No
545350	4616250	7.0	24-HR	20TH	0.0	7.0	No
545050	4616450	7.0	24-HR	5TH	0.0	7.0	No
541950	4616750	7.0	24-HR	1ST	0.6	7.0	No
544650	4616350	7.0	24-HR	3RD	0.0	7.0	No
545550	4616050	7.0	24-HR	21ST	0.0	7.0	No
543750	4614850	7.0	24-HR	1ST	0.0	7.0	No
544050	4616850	7.0	24-HR	1ST	0.0	7.0	No
545250	4616250	7.0	24-HR	16TH	0.0	7.0	No
545050	4616150	7.0	24-HR	4TH	0.0	7.0	No
541550	4616550	7.0	24-HR	1ST	0.6	7.0	No
543950	4615050	7.0	24-HR	1ST	0.0	7.0	No
545250	4616050	7.0	24-HR	6TH	0.0	7.0	No

Capital Costs for SCR to Control NO_X - 80 MMBtu/hr Auxiliary Boiler

Capital Cost Summary		Capital Cost
DIRECT COSTS		
Purchased Equipment and Direct Installation Costs		
Equipment[a]		$173,528
Instrumentation[b]		$0
Sales Tax (7% in Indiana)		$12,147
Freight (included in base equipment cost)		$0
PURCHASED EQUIPMENT COST (PEC)	**PEC =**	**$185,675**
TOTAL DIRECT CAPITAL COST (DCC)[b]	**DCC =**	**$185,675**
INDIRECT COSTS[c]		
Engineering (10% of PEC)		$18,567
General Facilities (5% of PEC)		$9,284
Process Contingency (5% of PEC)		$9,284
TOTAL INDIRECT CAPITAL COST (ICC)	**ICC =**	**$37,135**
PROJECT CONTINGENCY (15% of ICC + DCC) (PC)[c]	**PC =**	**$33,421**
OTHER PREPRODUCTION COSTS		
Preproduction Cost (2% of (DCC+ ICC + PC))		$5,125
TOTAL CAPITAL INVESTMENT (TCI = DC + IC + PC)	**TCI =**	**$261,356**

[a] Quote obtained from Taylorville Energy Center, PSD construction permit application (05040027), submitted in November 2009. Quote by Indeck Power Equipment Company in November 2009 was SCR cost of $500,000. Cost adjusted to 2011 dollars based on Consumer Price Index, and scaled using the sixth tenths power law to adjust for difference in airflow.

[b] Freight, instrumentation, initial catalyst charge, and direct installation costs are assumed to be included in the purchase cost quoted by Indeck in Tayloville Energy Center PSD construction permit application (05040027).

[c] U.S. EPA and OAQPS CCM, Section 4.2, Chapter 2, "Selective Catalytic Reduction (SCR)," Sixth Edition, October 2000.

SCR Cost Analysis to Control NO_X - 80 MMBtu/hr Auxiliary Boiler

Annual Cost Summary				Annual Cost
DIRECT ANNUAL COSTS				
OPERATION AND MAINTENANCE [c]				
Maintenance (1.5% of TCI)				$3,920
REAGENT [d]				
Requirement	1.1 lb/hr at	$412.74 per ton		$1,924
CATALYST				
Catalyst Replacement [e]				$37,135
Catalyst Life (years) [c]				3.00
Annual Interest Rate (%) [c]				7.00%
Future Worth Factor [c]				0.381
Total Annual Catalyst Replacement Cost				$14,150
UTILITIES [f]				
Electricity Cost	18.07 kW at	$0.0712 per kW-hr		$11,269
TOTAL DIRECT ANNUAL COSTS (DAC)			**DAC =**	**$31,264**
INDIRECT OPERATING COSTS [c]				
Overhead (0% for SCR)				$0
Administrative Charges (2% of TCI)				$5,227
Property Taxes (1% of TCI)				$2,614
Insurance (1% of TCI)				$2,614
Capital Recovery (CRF x TCI)				
20 years @	7.00% interest	CRF= 0.0944		$24,670
TOTAL INDIRECT ANNUAL COSTS (IAC)			**IAC =**	**$35,124**
TOTAL ANNUALIZED COST (TAC = DAC + IAC)			**TAC=**	**$66,389**

Cost Effectiveness Summary	
Annual Control Cost ($)	**$66,389**
Pollutant to be Removed [NO_X] (tpy) [g]	**8.06**
CONTROL COST EFFECTIVENESS ($/ton)	**$8,237**

[d] As shown in Appendix A.2.3 of U.S. EPA's *Petroleum Refinery Tier 2 BACT Analysis Report* dated January 16, 2001 (available at http://www.epa.gov/ttn/caaa/t1/memoranda/bactrpt.pdf), the ammonia injection rate was calculated based on the uncontrolled NO_X emissions from a ULNB assuming 1:1 ratio of NO_X to ammonia. The $300/ton reagent costs from this document was also used but was corrected for inflation.

[e] Catalyst replacement cost assumed to be 20% of the purchased equipment cost based on EPA CCM, Section 4.2, Chapter 2, "Selective Catalytic Reduction (SCR)," Sixth Edition, January 2002, pg. 2-8.

[f] Based on power consumption and electricity cost equations in EPA CCM, Section 4.2, Chapter 2. Assumes a duct pressure drop of 2 inches of water, catalyst pressure drop of 0.75 inches of water, and three catalyst layers. Electricity price is 2009 average retail electricity cost from the Northern Indiana Public Service Co., for the Industrial Sector in 2009 (www.eia.doe.gov), adjusted to 2011 dollars.

[g] NO_X emissions reductions were calculated assuming an exit concentration of 7 ppmv.

Capital and Annualized Costs for SNCR to Control NO_X - 80 MMBtu/hr Auxiliary Boiler

Cost Summary			Cost
TOTAL CAPITAL INVESTMENT (TCI = DCC + ICC + PC) [a]		**TCI =**	**$96,918**
DIRECT ANNUAL COST [b]			$32,306
Capital Recovery (CRF x TCI)			
20 years @ 7.00% interest	CRF[d] = 0.0944		$9,148
TOTAL ANNUALIZED COST		**TAC=**	**$41,454**

Cost Effectiveness Summary	
Annual Control Cost ($)	**$41,454**
Pollutant to be Removed [NO_X] (tpy)[c]	**5.50**
CONTROL COST EFFECTIVENESS ($/ton)	**$7,544**

[a] Based on $1,211/MMBtu/hr capital cost in 2011 dollars, calculated from the lower limit of the $900-$2,500/MMBtu/hr range provided in the EPA Air Pollution Control Technology Fact Sheet for SNCR in 1999 dollars.

[b] Based on $404/MMBtu/hr total annualized cost in 2011 dollars, calculated from the lower limit of the $300-$1,000/MMBtu/hr range provided in the EPA Air Pollution Control Technology Fact Sheet for SNCR in 1999 dollars.

[c] Emissions are conservatively based on 50 % control according to EPA Air Pollution Control Technology Fact Sheet for SNCR.

[d] Interest rate conservatively set at 7.00%, based on EPA's seven percent social interest rate from the OAQPS CCM Sixth Edition.

Capital Costs for Oxidation Catalyst to Control CO - 80 MMBtu/hr Auxiliary Boiler

Capital Cost Summary		Capital Cost
DIRECT COSTS		
Purchased Equipment Cost		
Base Equipment Cost[a]		$76,115
Instrumentation (10% of equipment)[b]		$7,611
Sales Tax (7% in Indiana)		$5,328
Freight (5% of Equipment) [a]		$3,806
Purchased Equipment Cost (PEC)	**PEC =**	**$92,860**
Direct Installation Costs [b]		
Foundation and supports (8% of PEC)		$7,429
Handling and erection (14% of PEC)		$13,000
Electrical (4% of PEC)		$3,714
Piping (2% of PEC)		$1,857
Insulation for ductwork (1% of PEC)		$929
Painting (1% of PEC)		$929
Direct Installation Cost (DIC)	**DIC =**	$27,858
TOTAL DIRECT COSTS (DC)	**DC =**	**$120,718**
INDIRECT COSTS[b]		
Engineering (10% of PEC)		$9,286
Construction and field expenses (5% of PEC)		$4,643
Contractor fees (10% of PEC)		$9,286
Start-up (2% of PEC)		$1,857
Performance test (1% of PEC)		$929
Contingencies (3% of PEC)		$2,786
TOTAL INDIRECT COSTS (IC)	**IC =**	**$28,787**
TOTAL CAPITAL INVESTMENT (TCI = DCC+ ICC)	**TCI =**	**$149,504**

[a] Estimated purchased equipment cost obtained in 2009 dollars from PSD construction permit application (05040027) for Taylorville Energy Center in Taylorville, IL submitted in November 2010. Cost adjusted to 2011 dollars using Consumer Price Index, and scaled using the sixth tenths power law to adjust for difference in airflow.

[b] EPA's Control Cost Manual (CCM) Section 3.2. Chapter 2 Table 2.8 Capital Cost Factors for Thermal and Catalytic Incinerators and Table 2.10 Annual Costs for Thermal and Catalytic Incinerators Example Problem.

Annual Costs for Oxidation Catalyst to Control CO - 80 MMBtu/hr Auxiliary Boiler

Annual Cost Summary		Annual Cost
DIRECT ANNUAL COSTS		
Operating Labor [c]		
Operator (0.5 hour/shift, 3 shifts per day, 183 days/year for 50% utilization @ $29.7/man-hr)		$8,153
Supervision (15% of Operator)		$1,223
Maintenance [c]		
Labor (0.5 hour/shift, 3 shifts per day, 183 days/year for 50% utilization @ $18.87/man-hr)		$5,180
Material (100% of maintenance labor)		$5,180
Catalyst Cost [d]		$22,145
TOTAL DIRECT ANNUAL COSTS (DAC)	**DAC =**	**$41,880**
INDIRECT ANNUAL COSTS [b]		
Overhead (60% of Operating Labor and Maintenance)		$11,841
Administrative Charges (2% of TCI)		$2,990
Property Taxes (1% of TCI)		$1,495
Insurance (1% of TCI)		$1,495
Capital Recovery (CRF x TCI)		
10 years @ 7.00% interest	CRF = 0.1424	$21,286
TOTAL INDIRECT ANNUAL COSTS (IAC)	**IAC =**	**$39,107**
TOTAL ANNUALIZED COST (TAC = DAC + IAC)	**TAC=**	**$80,988**

Cost Effectiveness Summary	
Annual Control Cost ($)	**$80,988**
Pollutant to be Removed [CO] (tpy)[e]	**26.0**
CONTROL COST EFFECTIVENESS ($/ton)	**$3,113**

[c] Labor rates based on data from the U.S Bureau of Labor Statistics May 2010 State Occupational Employment and Wage Estimates for Indiana (http://www.bls.gov/oes/current/oes_in.htm#51-0000), for the following Occupation Codes:
51-8013 Power Plant Operators
49-0000 Installation, Maintenance, and Repair Occupations

[d] Catalyst costs based upon the following data:

Catalyst Cost:	$50,061	Obtained from PSD construction permit application (05040027) for Taylorville Energy Center in Taylorville, IL, submited in November 2010, for replacement cost of catalyst on CCCT, scaled using sixth tenth power law. Not adjusted for CPI.
Catalyst Disposal Cost:	$4,551	
Sales Tax (7%)	$3,504	
Capital Recovery Factor	3 years @ 7%	0.381

[e] Based on a 90% control efficiency.

Capital Costs for Oxidation Catalyst to Control VOC - 80 MMBtu/hr Auxiliary Boiler

Capital Cost Summary		Capital Cost
DIRECT COSTS		
Purchased Equipment Cost		
Base Equipment Cost[a]		$76,115
Instrumentation (10% of equipment)[b]		$7,611
Sales Tax (7% in Indiana)		$5,328
Freight (5% of Equipment) [a]		$3,806
Purchased Equipment Cost (PEC)	**PEC =**	**$92,860**
Direct Installation Costs [b]		
Foundation and supports (8% of PEC)		$7,429
Handling and erection (14% of PEC)		$13,000
Electrical (4% of PEC)		$3,714
Piping (2% of PEC)		$1,857
Insulation for ductwork (1% of PEC)		$929
Painting (1% of PEC)		$929
Direct Installation Cost (DIC)	**DIC =**	$27,858
TOTAL DIRECT COSTS (DC)	**DC =**	**$120,718**
INDIRECT COSTS[b]		
Engineering (10% of PEC)		$9,286
Construction and field expenses (5% of PEC)		$4,643
Contractor fees (10% of PEC)		$9,286
Start-up (2% of PEC)		$1,857
Performance test (1% of PEC)		$929
Contingencies (3% of PEC)		$2,786
TOTAL INDIRECT COSTS (IC)	**IC =**	**$28,787**
TOTAL CAPITAL INVESTMENT (TCI = DCC+ ICC)	**TCI =**	**$149,504**

[a] Estimated purchased equipment cost obtained in 2009 dollars from PSD construction permit application (05040027) for Taylorville Energy Center in Taylorville, IL submited in November 2010. Cost adjusted to 2011 dollars using Consumer Price Index, and scaled using the sixth tenths power law to adjust for difference in airflow.

[b] EPA's Control Cost Manual (CCM) Section 3.2. Chapter 2 Table 2.8 Capital Cost Factors for Thermal and Catalytic Incinerators and Table 2.10 Annual Costs for Thermal and Catalytic Incinerators Example Problem.

Annual Costs for Oxidation Catalyst to Control VOC - 80 MMBtu/hr Auxiliary Boiler

Annual Cost Summary		Annual Cost
DIRECT ANNUAL COSTS		
Operating Labor [c]		
Operator (0.5 hour/shift, 3 shifts per day, 183 days/year for 50% utilization @ $29.7/man-hr)		$8,153
Supervision (15% of Operator)		$1,223
Maintenance [c]		
Labor (0.5 hour/shift, 3 shifts per day, 183 days/year for 50% utilization @ $18.87/man-hr)		$5,180
Material (100% of maintenance labor)		$5,180
Catalyst Cost [d]		$22,145
TOTAL DIRECT ANNUAL COSTS (DAC)	**DAC =**	**$41,880**
INDIRECT ANNUAL COSTS [b]		
Overhead (60% of Operating Labor and Maintenance)		$11,841
Administrative Charges (2% of TCI)		$2,990
Property Taxes (1% of TCI)		$1,495
Insurance (1% of TCI)		$1,495
Capital Recovery (CRF x TCI)		
10 years @ 7.00% interest	CRF = 0.1424	$21,286
TOTAL INDIRECT ANNUAL COSTS (IAC)	**IAC =**	**$39,107**
TOTAL ANNUALIZED COST (TAC = DAC + IAC)	**TAC=**	**$80,988**

Cost Effectiveness Summary	
Annual Control Cost ($)	**$80,988**
Pollutant to be Removed [VOM] (tpy) [e]	**0.9**
CONTROL COST EFFECTIVENESS ($/ton)	**$92,557**

[c] Labor rates based on data from the U.S Bureau of Labor Statistics May 2010 State Occupational Employment and Wage Estimates for Indiana (http://www.bls.gov/oes/current/oes_in.htm#51-0000), for the following Occupation Codes:
51-8013 Power Plant Operators
49-0000 Installation, Maintenance, and Repair Occupations

[d] Catalyst costs based upon the following data:

Catalyst Cost:	$50,061	Obtained from PSD construction permit application (05040027) for Taylorville Energy Center in Taylorville, IL, submited in November 2010, for replacement cost of catalyst on CCCT, scaled using sixth tenth power law. Not adjusted for CPI.
Catalyst Disposal Cost:	$4,551	
Sales Tax (7%)	$3,504	
Capital Recovery Factor	3 years @ 7%	0.381

[e] Based on a 50% control efficiency.

What if you are not satisfied with this decision and you want to file an appeal?

Who may file an appeal?
The decision described in the accompanying Notice of Decision may be administratively appealed. Filing an appeal is formally known as filing a "Petition for Administrative Review" to request an "administrative hearing."

If you object to this decision issued by the Indiana Department of Environmental Management (IDEM) and are: 1) the person to whom the decision was directed, 2) a party specified by law as being eligible to appeal, or 3) aggrieved or adversely affected by the decision, you are entitled to file an appeal. (An aggrieved or adversely affected person is one who would be considered by the court to be negatively impacted by the decision. If you file an appeal because you feel that you are aggrieved, it will be up to you to demonstrate in your appeal how you are directly impacted in a negative way by the decision).

The Indiana Office of Environmental Adjudication (OEA) was established by state law – see Indiana Code (IC) 4-21.5-7 – and is a separate state agency independent of IDEM. The jurisdiction of the OEA is limited to the review of environmental pollution concerns or any alleged technical or legal deficiencies associated with the IDEM decision making process. Once your request has been received by OEA, your appeal may be considered by an Environmental Law Judge.

What is required of persons filing an appeal?
Filing an appeal is a legal proceeding, so it is suggested that you consult with an attorney. Your request for an appeal must include your name and address and identify your interest in the decision (Or, if you are representing someone else, his or her name and address and their interest in the decision). In addition, please include a photocopy of the accompanying Notice of Decision or list the permit number and name of the applicant, or responsible party, in your letter.

Before a hearing is granted, you must identify the reason for the appeal request and the issues proposed for consideration at the hearing. You also must identify the permit terms and conditions that, in your judgment, would appropriately satisfy the requirements of law with respect to the IDEM decision being appealed. That is, you must suggest an alternative to the language in the permit (or other order, or decision) being appealed, and your suggested changes must be consistent with all applicable laws (See Indiana Code 13-15-6-2) and rules (See Title 315 of the Indiana Administrative Code, or 315 IAC).

The effective date of this agency action is stated on the accompanying Notice of Decision (or other IDEM decision notice). If you file a "Petition for Administrative Review" (appeal), you may wish to specifically request that the action be "stayed" (temporarily halted) because most appeals do not allow for an automatic "stay." If, after an evidentiary hearing, a "stay" is granted, the IDEM-approved action may be halted altogether, or only allowed to continue in part, until a final decision has been made regarding the appeal. However, if the action is not "stayed" the IDEM-approved activity will be allowed to continue during the appeal process.

(See reverse side)

Where can you file an appeal?
If you wish to file an appeal, you must do so in writing. There are no standard forms to fill out and submit, so you must state your case in a letter (called a petition for administrative review) to the Indiana Office of Environmental Adjudication (OEA). Do not send the original copy of your appeal request to IDEM. Instead, send or deliver your letter to:

The Indiana Office of Environmental Adjudication
100 North Senate Ave.
Indiana Government Center North
Room N501E
Indianapolis, IN 46204

If you file an appeal, also please send a copy of your appeal letter to the IDEM contact person identified in the Notice of Decision, and to the applicant (person receiving an IDEM permit, or other approval).

Your appeal (petition for administrative review) must be received by the Office of Environmental Adjudication in a timely manner. Different types of permit approvals have different deadlines for filing an appeal. The accompanying Notice of Decision (NOD) explains how to determine the due date for filing an appeal for this particular permit decision. To ensure that you meet this filing requirement, your appeal request must be:

1) Delivered in person to the OEA by the close-of-business on the due date. (If the due date falls on a day when the Office of Environmental Adjudication (OEA) is closed for the weekend or for a state holiday, then your petition will be accepted on the next business day on which OEA is open.); or
2) Given to a private carrier who will deliver it to the OEA on your behalf, (and from whom you must obtain a receipt dated on or before the due date); or
3) For those appeal requests sent by U.S. Mail, your letter must be postmarked by no later than midnight of the due date; or
4) Faxed to the OEA at 317/233-9372 before the close-of-business of the due date, provided that the original signed "Petition for Administrative Review" is also sent, or delivered, to the OEA in a timely manner.

What are the costs associated with filing an appeal?
The OEA does not charge a fee for filing documents for an administrative review or for the use of its hearing facilities. However, OEA does charge a fifteen cent ($.15) per page fee for copies of any documents you may request. Another cost that could be associated with your appeal would be for attorney's fees. Although you have the option to act as your own attorney, the administrative review and associated hearing are complex legal proceedings; therefore, you should consider whether your interests would be better represented by an experienced attorney.

What can you expect from the Office of Environmental Adjudication (OEA) after you file for an appeal?
The OEA will provide you with notice of any prehearing conferences, preliminary hearings, hearings, "stays," or orders disposing of the review of this decision. In addition, you may contact the OEA by phone at 317/232-8591 with any scheduling questions. However, technical questions should be directed to IDEM at the number indicated on the Notice of Decision.

Do not expect to discuss details of your case with the OEA other than in a formal setting such as a prehearing conference, a formal hearing, or a settlement conference. The OEA is not allowed to discuss a case without all sides being present. All parties to the proceeding are expected to appear at the initial prehearing conference.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
Toll Free (800) 451-6027
www.idem.IN.gov

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Willard Ladd
St. Joseph Energy Center, LLC
c/o Development Partners Group
11 Martine Ave, Flr. 9
White Plains, NY 10606

DATE: December 3, 2012

FROM: Matt Stuckey, Branch Chief
Permits Branch
Office of Air Quality

SUBJECT: Final Decision
Title V
141-31003-00579

Enclosed is the final decision and supporting materials for the air permit application referenced above. Please note that this packet contains the original, signed, permit documents.

The final decision is being sent to you because our records indicate that you are the contact person for this application. However, if you are not the appropriate person within your company to receive this document, please forward it to the correct person.

A copy of the final decision and supporting materials has also been sent via standard mail to:
OAQ Permits Branch Interested Parties List

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit. If you think you have received this document in error, please contact Joanne Smiddie-Brush of my staff at 1-800-451-6027 (ext 3-0185), or via e-mail at jbrush@idem.IN.gov.

Final Applicant Cover letter.dot 11/30/07

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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(317) 232-8603
Toll Free (800) 451-6027
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December 3, 2012

TO: New Carlisle Olive Township Library

From: Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: St. Joseph Energy Center, LLC
Permit Number: 141-31003-00579

You previously received information to make available to the public during the public comment period of a draft permit. Enclosed is a copy of the final decision and supporting materials for the same project. Please place the enclosed information along with the information you previously received. To ensure that your patrons have ample opportunity to review the enclosed permit, **we ask that you retain this document for at least 60 days.**

The applicant is responsible for placing a copy of the application in your library. If the permit application is not on file, or if you have any questions concerning this public review process, please contact Joanne Smiddie-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185.

Enclosures
Final Library.dot 11/30/07

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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Commissioner

100 North Senate Avenue
Indianapolis, Indiana 46204
(317) 232-8603
Toll Free (800) 451-6027
www.idem.IN.gov

TO: Interested Parties / Applicant

DATE: December 3, 2012

RE: St. Joseph Energy Center, LLC / 141-31003-00579

FROM: Matthew Stuckey, Branch Chief
Permits Branch
Office of Air Quality

In order to conserve paper and reduce postage costs, IDEM's Office of Air Quality is now sending many permit decisions on CDs in Adobe PDF format. The enclosed CD contains information regarding the company named above.

This permit is also available on the IDEM website at:
http://www.in.gov/ai/appfiles/idem-caats/

If you would like to request a paper copy of the permit document, please contact IDEM's central file room at:

Indiana Government Center North, Room 1201
100 North Senate Avenue, MC 50-07
Indianapolis, IN 46204
Phone: 1-800-451-6027 (ext. 4-0965)
Fax (317) 232-8659

Please Note: *If you feel you have received this information in error, or would like to be removed from the Air Permits mailing list, please contact Patricia Pear with the Air Permits Administration Section at 1-800-451-6027, ext. 3-6875 or via e-mail at PPEAR@IDEM.IN.GOV.*

Enclosures
CD Memo.dot 11/14/08

Mail Code 61-53

IDEM Staff	MIDENNEY 12/3/2012 St. Joseph Energy Center LLC 141-31003-00579 (final)			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Willard Ladd St. Joseph Energy Center LLC c/o Devlpmnt Partners Grp, 11 Martine Ave Fl 9 White Plains NY 10606 (Source CAATS) via confirm delivery									
2		Ken Herceg 211 W. Washington St, Ste 2100 South Bend IN 46601 *(Affected Party)*									
3		Keith Varga 54983 Tulip Rd New Carlisle IN 46552 *(Affected Party)*									
4		Mr. Wayne Falda South Bend Tribune 255 W Colfax Ave South Bend IN 46626 *(Affected Party)*									
5		New Carlisle Town Council 113 South Arch Street, P.O. Box 6 New Carlisle IN 46552 *(Local Official)*									
6		South Bend City Council / Mayors Office 227 W. Jefferson Blvd. South Bend IN 46601 *(Local Official)*									
7		St. Joseph County Board of Commissioners 227 West Jefferson Blvd, South Bend IN 46601 *(Local Official)*									
8		St. Joseph County Health Department 227 W Jefferson Blvd, Room 825 South Bend IN 46601-1870 *(Health Department)*									
9		New Carlisle Olive Township Library 408 S. Bray Street New Carlisle IN 46552 *(Library)*									
10		Jeffrey L. Rea 401 E. Colfax South Bend IN 46617 *(Affected Party)*									
11		Jack Daly P.O. Box 696 New Carlisle IN 46552 *(Affected Party)*									
12		Inland Steel Company 3210 Watling St East Chicago IN 46312 *(Affected Party)*									
13		NICTD 33 East US Hwy 12 Chesterton IN 46304 (Affected Party)									
14		Debruce Grain Inc 4100 N Mulberry Dr, Ste 300 Kansas City MO 64116 *(Affected Party)*									
15		Mr. Kenneth E. Sebasty 31527 US 20 New Carlisle IN 46552 *(Affected Party)*									

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.
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FACSIMILIE OF PS Form 3877

Mail Code 61-53

IDEM Staff	MIDENNEY 12/3/2012 St. Joseph Energy Center LLC 141-31003-00579 (final)			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Thomas H. & Nancy Lake Lake Farm Service Inc 54300 Walnut Rd New Carlisle IN 46552 (Affected Party)									
2		Kenneth P & Kimberley K Huston 29167 US Hwy 20 New Carlisle IN 46552 *(Affected Party)*									
3		Indiana/ Michigan Electric Company ATT: Tax Dept PO Box 16428 Columbus OH 43216 *(Affected Party)*									
4		Golden Realty LLC 65 Pheasant Dr East Greenwich RI 02818 *(Affected Party)*									
5		Lakes Farm Services LLC 4100 N Mulberry Dr, Ste 300 Kansas City MO 64116 *(Affected Party)*									
6		Susan Jones 2867 N 925 E Millcreek IN 46365 *(Affected Party)*									
7		Mike Compton 1345 Northside Blvd South Bend IN 46615 *(Affected Party)*									
8		Rafael Morton St. Joseph County Council County City Building 4th Floor South Bend IN 46601 *(Local Official)*									
9		Donald Fozo 3512 Sugar Maple Ct South Bend IN 46628 *(Affected Party)*									
10		James Scheetz 22405 New Rd South Bend IN 46614 *(Affected Party)*									
11		Charles Dadlow 29430 State Rd 2 Canton MI 46592 *(Affected Party)*									
12		Larry Truex 7955 N. LaPorte New Carlisle IN 46552 *(Affected Party)*									
13		Kenneth Carter 201 W. Ada New Carlisle IN 46552 (Affected Party)									
14		Murray Miller 23698 Western Ave South Bend IN 46619 *(Affected Party)*									
15		Elizabeth Miller 51677 Sycamore Rd New Carlisle IN 46552 *(Affected Party)*									

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.
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1		Thomas & Susan Baker 29779 Edison Rd New Carlisle IN 46552 (Affected Party)									
2		News WSBT-TV 1301 E. Douglas Rd Mishawaka IN 46545 *(Affected Party)*									
3		Thomas Swaney 32100 Edison Rd New Carlisle IN 46552 *(Affected Party)*									
4											
5											
6											
7											
8											
9											
10											
11											
12											
13											
14											
15											

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.
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