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: April 9, 2012

RE: PQ Corporation / 019-31174-00018

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 13-17-3-4 and 326 IAC 2, this permit modification 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 13-15-7-3 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 Environmental Adjudication, 100 North Senate Avenue, Government Center North, Suite N 501E, Indianapolis, IN 46204, **within eighteen (18) days of the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

(1) the date the document is delivered to the 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:

(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 a Title V operating permit 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
FNTV-PMOD.doc 3/27/08

IDEM

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April 9, 2012

George A. Monasky, Consultant
PQ Corporation
1101 Quartz Road
Clarksville, Indiana 47129

Re: Significant Permit Modification
No. 019-31174-00018 to
Part 70 Renewal No. T 019-23178-00018

Dear Mr. Monasky:

PQ Corporation was issued a Part 70 Operating Permit Renewal on September 4, 2008, for a stationary sodium silicate and sodium aluminosilicate manufacturing facility. An application requesting changes to this permit was received on November 21, 2011. Pursuant to the provisions of 326 IAC 2-7-12, a significant permit modification to this permit is hereby approved as described in the attached Technical Support Document.

PQ Corporation submitted an application to revise permit conditions related to the use of biodiesel in the two (2) fire tube boilers (SG-1001 and SG-1002) and the melting furnace. IDEM reviewed this request under Part 70 Operating Permit Renewal No. T019-23178-00018; however, additional permit conditions are required to allow these units to operate using biodiesel. This significant modification to the Part 70 Operating Permit Renewal incorporates the applicable permit conditions to allow PQ Corporation to use biodiesel.

All other conditions of the permit shall remain unchanged and in effect. For your convenience, the entire Part 70 Operating Permit as modified will be provided at issuance. A copy of this permit is available on the Internet at: www.in.gov/ai/appfiles/idem-caats/.

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 David Matousek, OAQ, 100 North Senate Avenue, MC 61-53, Room 1003, Indianapolis, Indiana, 46204-2251, or call at (800) 451-6027, and ask for David Matousek or extension (2-8253), or dial (317) 232-8253.

Sincerely,

Tripurari Sinha

Tripurari P. Sinha, Ph. D., Section Chief
Permits Branch
Office of Air Quality

Attachments:
Updated Permit,

DJM

cc: File – Clark County
Clark County Health Department
U.S. EPA, Region V
Compliance and Enforcement Branch

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Toll Free (800) 451-6027
www.idem.IN.gov

Part 70 Operating Permit
OFFICE OF AIR QUALITY

PQ Corporation
1101 Quartz Road
Clarksville, Indiana 47129

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

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

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

Operation Permit No.: T019-23178-00018	
Issued by/Original Signed by: Alfred C. Dumaual, Ph.D., Section Chief Permits Branch Office of Air Quality	Issuance Date: September 4, 2008 Expiration Date: September 4, 2013

First Significant Permit Modification No.: 019-29779-00018; and
Second Significant Permit Modification No.: 019-30719-00018.

Significant Permit Modification No.: 019-31174-00018	
Issued by: Tripurari Sinha Tripurari P. Sinha, Ph. D., Section Chief Permits Branch Office of Air Quality	Issuance Date: April 9, 2012 Expiration Date: September 4, 2013

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SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 through A.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 sodium silicate and sodium aluminosilicate manufacturing facility.

Source Address:	1101 Quartz Road, Jeffersonville, Indiana 47129
General Source Phone Number:	(812) 288-7186
SIC Code:	2819
County Location:	Clark
Source Location Status:	Nonattainment for $PM_{2.5}$ standard Attainment for all other criteria pollutants
Source Status:	Part 70 Operating Permit Program Minor Source, under PSD and NA NSR 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) Two (2) fire tube boilers (SG-1001 and SG-1002), constructed in 1991, each rated at seventeen and five-tenths (17.5) million British thermal units (MMBtu) per hour and exhausting at one (1) stack, identified as S-2. The boilers are fired by natural gas, No. 2 fuel oil and No. 4 fuel oil or biodiesel as a backup fuel. [40 CFR 60, Subpart Dc]

(b) One (1) natural gas-fired dryer, constructed in 1991, rated at ten (10) million British thermal units (MMBtu) per hour and exhausting through a baghouse separator with no unit identification at stack S-6. The dryer uses propane as a backup fuel. This dryer is an insignificant source when burning natural gas.

(c) One (1) melting furnace with a maximum heat input capacity of 19.7 MMBtu per hour, fired by natural gas or fuel oil, and exhausting at stack S-1. The furnace is fired using natural gas, with No. 2 fuel oil and No. 4 fuel oil, biodiesel/No.2 fuel or any combination of the aforementioned fuel oils as secondary fuels. The furnace was constructed in 1938 and rebuilt in 1998 and 2003 pursuant to Administrative Amendment 019-16660-00018 issued on February 11, 2003.

(d) Material storage and handling facilities, constructed before August 7, 1977, with a maximum material throughput of 155 tons per hour, including:

(1) Aluminum trihydrate storage and transfer facilities, with a maximum material throughput of 33.5 tons per hour, consisting of one (1) pneumatic conveyor system equipped with a baghouse with no unit identification exhausting at stack S-3; one (1) 400 ton capacity storage silo equipped with a baghouse with no unit identification exhausting at stack S-4; and one (1) weigh bin with a maximum

capacity of 12,580 pounds per hour equipped with a baghouse with no unit identification exhausting at stack S-5.

(2) Sodium silicate storage and transfer facilities, with a maximum of material throughput of 33.5 tons per hour, consisting of a bucket conveyor system and one (1) 1,400 ton capacity storage silo. Particulate emissions are controlled by a rotoclone and a baghouse with no unit identification for either particulate control device. The rotoclone exhausts to stack R-12. The baghouse exhausts to stack S-12.

(3) Sand and soda ash storage and transfer facilities, with a total maximum material throughput of 84 tons per hour, consisting of the following:

(A) one (1) 1,500 ton capacity storage silo for sand, equipped with one (1) bin vent with a design grain loading of 0.0034 gr/dscf and design airflow rate 277 dscfm, with emissions from the bin vent being exhausted through stack SSBV;

(B) one (1) 940 ton capacity storage silo for soda ash, with the emissions from both silos being controlled by one (1) baghouse with no unit identification, with the sand storage emissions not exhausted through stack SSBV and soda ash storage emissions exhausted through stack S-8;

(C) two (2) weigh hoppers connected to one (1) baghouse with no unit identification exhausting at stack S-7;

(D) one (1) pneumatic conveying system for the transfer of sand and soda ash from the weigh hoppers to the furnace equipped with a baghouse with no unit identification.

(4) Sodium aluminosilicate transfer, storage, and loading facilities, with a maximum material throughput of 35 tons per hour, consisting of the following:

(A) a pneumatic conveyor system for transfer to the storage silos, equipped with one (1) baghouse separator with no unit identification for particulate control exhausting at stack S-6;

(B) two (2) 625 ton capacity storage silos each equipped with one (1) baghouse with no unit identification for particulate control exhausting at stacks S-9 and S-10;

(C) one (1) pneumatic conveyor system for truck and rail car loading, equipped with a baghouse with no unit identification for particulate control exhausting at stack S-11.

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

(b) Degreasing operations that do not exceed 145 gallons per 12 months. [326 IAC 8-3-2] [326 IAC 8-3-5]

(c) Other emission units and activities with potential emissions below the threshold in 326 IAC 2-7-1(21):

(1) Aluminum trihydrate unloading operations emitting less than five (5) pounds per hour of particulate matter. [326 IAC 6.5-1-2 (a)]

(2) Sand and soda ash unloading operations emitting less than five (5) pounds per hour of particulate matter. [326 IAC 6.5-1-2 (a)]

(3) Sodium Silicate unloading operations emitting less than five (5) pounds per hour of particulate matter. [326 IAC 6.5-1-2 (a)]

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).

SECTION B GENERAL CONDITIONS

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

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

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

(a) The Part 70 Operating Permit Renewal, T019-23178-00018, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(1) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(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.9 Annual Compliance Certification [326 IAC 2-7-6(5)]

(a) The Permittee shall annually submit a compliance certification report which addresses the status of the source's compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. All certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted no later than April 15 of each year to:

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

and

United States Environmental Protection Agency, Region 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.10 Preventive Maintenance Plan [326 IAC 2-7-5(12)] [326 IAC 1-6-3]

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

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

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

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

The Permittee shall implement the PMPs.

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

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

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

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

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

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

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

The Permittee shall implement the PMPs.

(c) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions. The PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

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

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

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

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

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

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

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

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ, or Southeast Regional Office no later than four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance and Enforcement Branch), or
Telephone Number: 317-233-0178 (ask for Office of Air Quality, Compliance and Enforcement Branch)
Facsimile Number: 317-233-6865
Southeast Regional Office phone: (812) 358-2027; fax: (812) 358-2058
Southwest Regional Office phone: (812) 380-2305; fax: (812) 380-2304

(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

no later than 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.12 Permit Shield [326 IAC 2-7-15] [326 IAC 2-7-20] [326 IAC 2-7-12]

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

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

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

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

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

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

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

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

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

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

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

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

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

(a) All terms and conditions of permits established prior to T019-23178-00018 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

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

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

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

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

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

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

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-7-5(6)(C)] The notification by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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.16 Permit Renewal [326 IAC 2-7-3] [326 IAC 2-7-4] [326 IAC 2-7-8(e)]

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(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.17 Permit Amendment or Modification [326 IAC 2-7-11] [326 IAC 2-7-12]

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

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

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

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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.18 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)] [326 IAC 2-7-12(b)(2)]

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

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

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

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

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

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

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

(4) The Permittee notifies the:

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

and

United States Environmental Protection Agency, Region 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.

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

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

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

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

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

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

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

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

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

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

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

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

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

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(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.23 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)] [326 IAC 2-1.1-7]

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

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

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

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

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

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

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

C.1 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 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.12 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.13 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.14 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.15 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6]

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

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

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

Stratospheric Ozone Protection

C.17 Compliance with 40 CFR 82 and 326 IAC 22-1

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

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) Two (2) fire tube boilers (SG-1001 and SG-1002), constructed in 1991, each rated at seventeen and five-tenths (17.5) million British thermal units (MMBtu) per hour and exhausting at one (1) stack, identified as S-2. The boilers are fired by natural gas, No. 2 fuel oil and No.4 fuel or biodiesel as a backup fuel. [40 CFR 60, Subpart Dc]

(b) One (1) natural gas-fired dryer, constructed in 1991, rated at ten (10) million British thermal units (MMBtu) per hour and exhausting through a baghouse separator with no unit identification at stack S-6. The dryer uses propane as a backup fuel.

(c) One (1) melting furnace with a maximum heat input capacity of 19.7 MMBtu per hour, fired by natural gas or fuel oil, and exhausting at stack S-1. The furnace is fired using natural gas, with No. 2 fuel oil and No. 4 fuel oil, biodiesel/No.2 fuel or any combination of the aforementioned fuel oils as secondary fuels. The furnace was constructed in 1938 and rebuilt in 1998 and 2003 pursuant to Administrative Amendment 019-16660-00018 issued on February 11, 2003.

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

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

D.1.1 Particulate Matter (PM) [326 IAC 6.5-1-2(b)]

Pursuant to 326 IAC 6.5-1-2(b)(2) (Nonattainment Area Particulate Limitations for Fossil Fuel Fired Steam Generators; Liquid Fuel) and 326 IAC 6.5-1-2(b)(3) (Nonattainment Area Particulate Limitations for Fossil Fuel Fired Steam Generators; Gaseous Fuel), particulate matter emissions from the boilers (SG-1001 and SG-1002) shall be limited to 0.15 pounds per million Btu heat input when fuel oil is burned and 0.01 grains per dry standard cubic foot when natural gas is burned.

D.1.2 Particulate Matter (PM) [326 IAC 6.5-1-2(a)]

Pursuant to 326 IAC 6.5-1-2(a) (Particulate Emission Limitations), the particulate matter emissions from the dryer shall be limited to 0.03 grains per dry standard cubic foot.

D.1.3 Particulate Matter (PM) [326 IAC 6.5-2-9]

Pursuant to 326 IAC 6.5-2-9 (PQ Corporation), the particulate matter emissions from the furnace shall be limited to 51.8 tons per year and 1.4 pounds per ton of sodium silicate produced.

D.1.4 PSD Minor Limit [326 IAC 2-2]

The input of natural gas to the furnace and furnace natural gas equivalents shall be limited to 180 MMSCF per twelve (12) consecutive month period. NO_x emissions from the furnace shall not exceed 1,091 lbs/MMSCF when burning natural gas and 102 lbs/kgal when burning No. 2 fuel oil, No. 4 fuel oil or a blend of No. 2 and No. 4 fuel oils, biodiesel/No.2 fuel or any combination of the aforementioned fuel oils. For purposes of determining compliance:

(a) Every gallon of No.2 fuel oil, No. 4 fuel oil or combination of No.2 and No. 4 fuel oils, biodiesel/No.2 fuel or any combination of the aforementioned fuel oils burned in the furnace shall be equivalent to 93.5 cubic feet of natural gas based on nitrogen oxides emissions.

(b) Every standard cubic foot of natural gas burned in either boiler SG-1001 or SG-1002 is equivalent to burning 0.092 standard cubic feet of natural gas in the furnace based on nitrogen oxides emissions.

(c) Every gallon of No.2 fuel oil, No.4 fuel oil, biodiesel or combination of the fuel oils burned in either boiler SG-1001 or SG-1002 is equivalent to burning 18.33 standard cubic feet of natural gas in the furnace based on nitrogen oxides emissions.

(d) Every standard cubic foot of natural gas burned in dryer is equivalent to burning 0.092 standard cubic feet of natural gas in the furnace based on nitrogen oxides emissions.

This limit is required to limit the emissions of nitrogen oxides from the entire source to less than one hundred (100) tons per twelve (12) consecutive month period. Compliance with this limit will also limit emissions of sulfur oxides to less than one hundred (100) tons per twelve (12) consecutive month period. Compliance with this limit makes 326 IAC 2-2 (PSD) not applicable.

D.1.5 Sulfur Dioxide (SO_2) [326 IAC 7-1.1-1] [326 IAC 7-2-1]

(a) Pursuant to 326 IAC 7-1.1 (SO_2 Emissions Limitations) the SO_2 emissions from the two (2) 17.5 MMBtu/hr oil-fired boilers (SG-1001 and SG-1002) shall not exceed five tenths (0.5) pound per million British thermal units heat input while combusting any fuel oil. Pursuant to 326 IAC 7-2-1(d)(2), compliance shall be determined using a calendar month average sulfur dioxide emission rate in pounds per MMBtu.

(b) Pursuant to 326 IAC 7-1.1 (SO_2 Emissions Limitations), the SO_2 emissions from the melting furnace shall not exceed five-tenths (0.5) pound per million Btu heat input while combusting any fuel oil. Pursuant to 326 IAC 7-2-1(d)(2), compliance shall be determined using a calendar month average sulfur dioxide emission rate in pounds per MMBtu.

D.1.6 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan (PMP) is required for each facility 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 [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)])]

D.1.7 Testing Requirements [326 IAC 2-7-6(1),(6)]

In order to demonstrate the compliance status with Condition D.1.4 and Condition D.1.5, and not later than 180 days after the initial usage of biodiesel as fuel in the melting furnace or boilers SG-1001 or SG-1002, the Permittee shall perform a one-time stack test, to verify the NOx and SO2 emission factors used to determine the potential emissions from one of the boilers and the melting furnace while combusting biodiesel utilizing methods approved by the commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee’s obligation with regard to the performance testing required by this condition.

D.1.8 Particulate Control [326 IAC 2-7-6(6)]

(a) In order to ensure compliance with Condition D.1.2 the baghouse (exhausting to Stack S-6) for PM and PM_{10} control shall be in operation and control emissions from the dryer at all times that the dryer is in operation.

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

D.1.9 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3-7-4]

Compliance with the sulfur dioxide limits in Condition D.1.5(a) and D.1.5(b) for the two (2) boilers and melting furnace shall be determined utilizing one of the following options.

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

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

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

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

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

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

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

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

D.1.10 Visible Emissions Notations

(a) Visible emission notations of the boiler stack exhausts (stack S-2), the dryer stack exhausts stack (S-6), and the furnace stack exhaust (stack S-1) shall be performed once per day during normal daylight operations when burning fuel oil. A trained employee shall record whether emissions are normal or abnormal.

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

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

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

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

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

D.1.11 Record Keeping Requirements

(a) To document the compliance status with Condition D.1.4, the Permittee shall maintain records in accordance with (1) through (6) below. Note that pursuant to 40 CFR 60 Subpart Dc, the fuel oil sulfur limit applies at all times including periods of startup, shutdown, and malfunction.

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

(2) Actual fuel oil (No. 2, No. 4, biodiesel or a combination of the aforementioned) and natural gas usage since last compliance determination period and equivalent sulfur dioxide and NO_X emissions;

(3) To certify compliance when burning natural gas only, the Permittee shall maintain records of fuel used; and

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

(4) Fuel supplier certifications;

(5) The name of the fuel supplier; and

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

(b) To document the compliance status with Condition D.1.11, the Permittee shall maintain a daily record of visible emission notations of the boiler stack exhausts (stack S-2) and the furnace stack exhaust (stack S-1) while combusting fuel oil. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the process did not operate that day).

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

D.1.12 Reporting Requirements for Nitrogen Oxides (NO_X)

A quarterly summary of the information to document the compliance status with Condition D.1.4 shall be submitted using the quarterly reporting form located at the end of this permit, or its equivalent, no later than thirty (30) days after the end of each quarter being reported. Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition. The report submitted by the Permittee requires 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 D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(d) Material storage and handling facilities, constructed before August 7, 1977, with a maximum material throughput of 155 tons per hour, including:

(1) Aluminum trihydrate storage and transfer facilities, with a maximum material throughput of 33.5 tons per hour, consisting of one (1) pneumatic conveyor system equipped with a baghouse with no unit identification exhausting at stack S-3; one (1) 400 ton capacity storage silo equipped with a baghouse with no unit identification exhausting at stack S-4; and one (1) weigh bin with a maximum capacity of 12,580 pounds per hour equipped with a baghouse with no unit identification exhausting at stack S-5.

(2) Sodium silicate storage and transfer facilities, with a maximum of material throughput of 33.5 tons per hour, consisting of a bucket conveyor system and one (1) 1,400 ton capacity storage silo. Particulate emissions are controlled by a rotoclone and a baghouse with no unit identification for either particulate control device. The rotoclone exhausts to stack R-12. The baghouse exhausts to stack S-12.

(3) Sand and soda ash storage and transfer facilities, with a total maximum material throughput of 84 tons per hour, consisting of the following:

(A) one (1) 1,500 ton capacity storage silo for sand, equipped with one (1) bin vent with a design grain loading of 0.0034 gr/dscf anddesign airflow rate 277 dscfm, with emissions from the bin vent being exhausted through stack SSBV;

(B) one (1) 940 ton capacity storage silo for soda ash, with the emissions from both silos being controlled by one (1) baghouse with no unit identification, with the sand storage emissions not exhausted through stack SSBV and soda ash storage emissions exhausted through stack S-8;

(C) two (2) weigh hoppers connected to one (1) baghouse with no unit identification exhausting at stack S-7;

(D) one (1) pneumatic conveying system for the transfer of sand and soda ash from the weigh hoppers to the furnace equipped with a baghouse with no unit identification.

(4) Sodium aluminosilicate transfer, storage, and loading facilities, with a maximum material throughput of 35 tons per hour, consisting of the following:

(A) a pneumatic conveyor system for transfer to the storage silos, equipped with one (1) baghouse separator with no unit identification for particulate control exhausting at stack S-6;

(B) two (2) 625 ton capacity storage silos each equipped with one (1) baghouse with no unit identification for particulate control exhausting at stacks S-9 and S-10;

(C) one (1) pneumatic conveyor system for truck and rail car loading, equipped with a baghouse with no unit identification for particulate control exhausting at stack S-11.

(e) Zeolite packaging line with a day silo, to be constructed in 2011, identified as T1710, with a maximum capacity of 5000.00 tons of zeolite per year, using baghouse 1707 as control, and exhausting to stack S-11.

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

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

D.2.1 PSD Minor Limit [326 IAC 2-2]

The Permittee shall be subject to the following PM, PM_{10}, $PM_{2.5}$ limitations:

Unit	**PM Limit** (lbs/hr)	**PM_{10} Limit** (lbs/hr)	**$PM_{2.5}$ Limit** (lbs/hr)
S-3 Baghouse	1.06	1.06	1.06
S-12 Baghouse	1.06	1.06	1.06
R-12 Rotoclone	1.06	1.06	1.06
S-8 Baghouse	1.32	1.32	1.32
S-7 Baghouse	1.32	1.32	1.32
S-6 Baghouse	0.55	0.55	0.55
S-11 Baghouse	0.55	0.55	0.55

Compliance with these PM, PM_{10}, $PM_{2.5}$ emission limits from the storage and handling facilities, in conjunction with the total potential to emit of PM, PM_{10}, and $PM_{2.5}$ from the rest of the source shall ensure that the source-wide PM, PM_{10}, $PM_{2.5}$ emissions are less than one hundred (100) tons per twelve consecutive month period, rendering the requirements of 326 IAC 2-2 not applicable to the entire source.

D.2.2 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan (PMP) is required for each facility 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.

D.2.3 Particulate Matter (PM) [326 IAC 6.5-1-2(a)]

Pursuant to 326 IAC 6.5-1-2(a) (Particulate Emission Limitations), the particulate matter emissions from the aluminum trihydrate storage and transfer facilities; sodium silicate storage and transfer facilities; sand and soda ash transfer facilities; and the sodium aluminosilicate transfer, storage, and loading facilities shall be limited to 0.03 grains per dry standard cubic foot.

Compliance Determination Requirements

D.2.4 Particulate Control [326 IAC 2-7-6(6)]

(a) In order to ensure compliance with Condition D.2.1 and D.2.3, the baghouses (exhausting to Stacks S-3, S-4, S-5, S-6, S-7, S-8, S-9, S-10 and S-11) for PM and PM_{10} control shall be in operation and control emissions from the storage and conveyance of sand, soda ash, aluminum trihydrate, sodium silicate, and sodium aluminosilicate at all times that the sodium silicate or sodium aluminosilicate production facilities are in operation.

In order to ensure compliance with Condition D.2.1 and D.2.3, the baghouse or W-Rotoclone shall operate and control emissions from the storage and conveyance of sodium silicate."

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

D.2.5 Testing Requirements [326 IAC 2-7-6(1),(6)]

(a) In order to demonstrate the compliance status with Condition D.2.1, the Permittee shall perform PM, PM10 and PM2.5 testing for baghouses S-3, S-6, S-7, S-8 and S-11 utilizing methods approved by the commissioner at least once every twenty (20) years from the date of the most recent valid compliance demonstration. Repeat testing on at least one of the baghouses identified as S-3, S-6, S-7, S-8, S-11 and S-12 shall be conducted every five (5) years and shall be conducted in a manner to ensure the time period between tests on each unit is at least once every twenty (20) years. 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 the compliance status with Condition D.2.1 and not later than one hundred eighty (180) days after the issuance of this permit, Permit No 019-30685-00018, the Permittee shall perform PM, PM10 and PM2.5 testing on baghouse S-12, utilizing methods approved by the commissioner at least once every twenty (20) years from the date of the most recent valid compliance demonstration. Repeat testing on at least one of the baghouses identified as S-3, S-6, S-7, S-8, S-11 and S-12 shall be conducted every five (5) years and shall be conducted in a manner to ensure the time period between tests on each unit is at least once every twenty (20) years. 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) No later than one hundred eighty (180) days of operation of the rotoclone used in conjunction with the storage and conveyance of sand, soda ash, aluminum trihydrate, sodium silicate, and sodium aluminosilicate, in order to demonstrate the compliance status with Condition D.2.1, the Permittee shall perform PM/PM10/PM2.5 testing from the Rotoclone and establish the a minimum flow rate (in gallons per minute (GPM)) across the rotoclone. This testing shall be repeated at least once every twenty (20) years from the date of the most recent valid compliance demonstration.

Section C – Performance Testing contains the Permittee's obligations with regard to the testing required by this condition.

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

D.2.6 Visible Emissions Notations

(a) Visible emission notations of stack exhausts S-3, S-4, S-5, S-6, S-7, S-8, S-9, S-10, and S-11, shall be performed once per day during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

In the event that the W-Rotoclone is not operating, a trained employee shall record whether the emissions are normal or abnormal from stack S-12.

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

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

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

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

D.2.7 Parametric Monitoring

(a) To demonstrate the compliance status with Condition D.2.4, the Permittee shall record the pressure drop across the baghouses used in conjunction with the storage and conveyance of sand, soda ash, aluminum trihydrate, sodium silicate, and sodium aluminosilicate, at least once per day when the material storage and conveyance systems are in operation. When, for any one reading, the pressure drop across the baghouse is outside of the normal range, the Permittee shall take a reasonable response. The normal range for this unit is a pressure drop between 1.0 and 6.0 inches of water unless a different upper-bound or lower-bound value for this range is determined during the latest stack test. A pressure reading that is outside the above mentioned range is not a deviation from this permit.

(b) The Permittee shall record the flow rate across the rotoclone used in conjunction with the storage and conveyance of sand, soda ash, aluminum trihydrate, sodium silicate, and sodium aluminosilicate, at least once per day when the material storage and conveyance systems are in operation. When for any one reading, the flow rate across the rotoclone is below 4.0 gallons per minute (GPM), or the minimum flow rate established during the most recent valid compliance demonstration, the Permittee shall take reasonable response steps. A flow rate that is below the above mentioned minimum is not a deviation from this permit.

(c) Failure to take response steps shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

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

D.2.8 Broken or Failed Bag Detection

(a) For a single compartment baghouse controlling emissions from a process operated continuously, a failed unit and the associated process shall be shut down immediately until the failed unit has been repaired or replaced. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions).

(b) For a single compartment baghouse controlling emissions from a batch process, the feed to the process shall be shut down immediately until the failed unit has been repaired or replaced. The emissions unit shall be shut down no later than the completion of the processing of the material in the line. Operations may continue only if the event qualifies as an emergency and the Permittee satisfies the requirements of the emergency provisions of this permit (Section B - Emergency Provisions).

Bag failure can be indicated by a significant drop in the baghouse's pressure reading with abnormal visible emissions, by an opacity violation, or by other means such as gas temperature, flow rate, air infiltration, leaks, dust traces or triboflows.

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

D.2.9 Record Keeping Requirements

(a) To document the compliance status with Condition D.2.6, the Permittee shall maintain daily records of visible emission notations of the exhaust from stacks S-3, S-4, S-5, S-6, S-7, S-8, S-9, S-10, S-11 and S-12 (when the Rotoclone is not operating) once per day. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that day).

(b) To document the compliance status with Condition D.2.7, the Permittee shall maintain records once per day of the flow rate of water across the rotoclone and the pressure drop across the baghouse (when the Rotoclone is not in operation) used in conjunction with the storage and conveyance of sand, soda ash, aluminum trihydrate, sodium silicate, and sodium aluminosilicate. The Permittee shall include in its daily record when a flow rate or a pressure drop reading is not taken and the reason for the lack of pressure drop reading (e.g. the process did not operate that day.)

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

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) Degreasing operations not exceeding 145 gallons per 12 months. [326 IAC 8-3-2] [326 IAC 8-3-5]

(b) Material unloading operations, including:

(1) Aluminum trihydrate unloading operations emitting less than five (5) pounds per hour of particulate matter. [326 IAC 6.5-1-2 (a)]

(2) Sand and soda ash unloading operations emitting less than five (5) pounds per hour of particulate matter. [326 IAC 6.5-1-2 (a)]

(3) Sodium Silicate unloading operations emitting less than five (5) pounds per hour of particulate matter. [326 IAC 6.5-1-2 (a)]

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

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

D.3.1 Volatile Organic Compounds (VOC) [326 IAC 8-3-2]

Pursuant to 326 IAC 8-3-2 (Cold Cleaner Operations) for cold cleaning operations existing as of January 1, 1980, located in Clark County and which have potential emissions of one hundred (100) tons or greater per year, the owner or operator 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.3.2 Volatile Organic Compounds (VOC) [326 IAC 8-3-5]

(a) Pursuant to 326 IAC 8-3-5(a) (Cold Cleaner Degreaser Operation and Control), the owner or operator of a cold cleaner degreaser facility without remote solvent reservoirs, existing as of January 1, 1980, located in Clark, Elkhart, Floyd, Lake, Marion, Porters, or St. Joseph Counties, 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 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 the 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 and 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, and heavier than, water.

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

(b) Pursuant to 325 IAC 8-3-5(b) (Cold Cleaner Degreaser Operation and Control), the owner or operator of a cold cleaning facility, existing as of July 1, 1990, shall ensure 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.

D.3.3 Particulate Matter (PM) [326 IAC 6.5-1-2(a)]

Pursuant to 326 IAC 6.5-1-2(a) (Particulate Emission Limitations), the particulate matter emissions from the unloading of aluminum trihydrate, sand, soda ash, and sodium silicate shall be limited to 0.03 grains per dry standard cubic foot.

SECTION E.1 Standard of Performance for Industrial-Commercial-Institutional Steam Generating Units Requirements

Emission Unit Description:

(a) Two (2) fire tube boilers (SG-1001 and SG-1002), constructed in 1991, each rated at seventeen and five-tenths (17.5) million British thermal units (MMBtu) per hour and exhausting at one (1) stack, identified as S-2. The boilers are fired by natural gas, No. 2 fuel oil and No.4 fuel or biodiesel as a backup fuel. [40 CFR 60, Subpart Dc]

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

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

E.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 boilers SG-1001 and SG-1002, except as otherwise specified in 40 CFR Part 60, Subpart Dc.

E.1.2 Standard of Performance for Industrial-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 Standard of Performance for Industrial-Commercial-Institutional Steam Generating Units, which are incorporated by reference as 326 IAC 12, and included as Attachment A, for boilers SG-1001 and SG-1002 as specified as follows:

(a) 40 CFR 60.40c
(b) 40 CFR 60.41c
(c) 40 CFR 60.42c (d), (h)(1), (2), (i), (j)
(d) 40 CFR 60.43c (d), (e)
(e) 40 CFR 60.44c
(f) 40 CFR 60.45c
(g) 40 CFR 60.46c
(h) 40 CFR 60.47c
(i) 40 CFR 60.48c
(j) 40 CFR 60.48c

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY

PART 70 OPERATING PERMIT
CERTIFICATION

Source Name: PQ Corporation
Source Address: 1101 Quartz Road, Clarksville, IN 47129
Part 70 Permit No.: T019-23178-00018

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: PQ Corporation
Source Address: 1101 Quartz Road, Clarksville, IN 47129
Part 70 Permit No.: T019-23178-00018

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), no later than four (**4**) daytime business hours (1-800-451-6027 or 317-233-0178, ask for Compliance and Enforcement Branch); and • The Permittee must submit notice in writing or by facsimile no later than two (**2**) 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 Describe: 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:	PQ Corporation
Source Address:	1101 Quartz Road, Clarksville, IN 47129
Part 70 Permit No.:	T019-23178-00018
Facility:	Melting Furnace exhausting at S-1, Boilers SG-1001 & SG-1002, and Natural Gas Dryer exhausting at S-6
Parameter:	NO_X
Limit:	180 MMCF of furnace natural gas or furnace natural gas equivalents per twelve (12) consecutive month period.

YEAR: _____

Month	Fuel Usage for This Month (gallons)	Fuel Usage for Previous 11 Months (gallons)	Fuel Usage for 12-Month Period (gallons)

☐ No deviation occurred in this quarter.

☐ Deviations 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: PQ Corporation
Source Address: 1101 Quartz Road, Clarksville, IN 47129
Part 70 Permit No.: T019-23178-00018

Months: __________ **to** __________ **Year:** ________

Page 1 of 2

This report shall be submitted quarterly based on a calendar year. Proper notice submittal under Section B – Emergency Provisions satisfies the reporting requirements of this paragraph. 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: ______________________________

Indiana Department of Environmental Management
Office of Air Quality

Attachment A

40 CFR 60, Subpart Dc — Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Source Description and Location

Source Name:	**PQ Corporation**
Source Location:	**1101 Quartz Road, Clarksville, Indiana 47129**
County:	**Clark County**
SIC Code:	**2819**
Operation Permit No.:	**T 019-23178-00018**
Permit Reviewer:	**David J. Matousek**

Complete Text of 40 CFR 60, Subpart Dc

40 CFR 60, 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:

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

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:

$$\%R_go = 100\left(1 - \frac{E_{ao}^{\circ}}{E_{ai}^{\circ}}\right)$$

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.

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§ 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_2emissions. 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]

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Part 70 Significant Permit Modification

Source Description and Location

Source Name:	PQ Corporation
Source Location:	1101 Quartz Road, Clarksville, Indiana 47129
County:	Clark
SIC Code:	2819
Operation Permit Renewal No.:	T 019-23178-00018
Issuance Date:	September 4, 2008
Significant Permit Modification No.:	019-31174-00018
Permit Reviewer:	David Matousek

Existing Approvals

The source was issued Part 70 Operating Permit No. 019-23178-00018 on September 04, 2008. The source has since received the following approvals:

(a) Significant Permit Modification No. 019-29779-00018, issued on June 2, 2011;
(b) Exemption No. 019-31060-00018, issued on November 3, 2011;
(c) Significant Source Modification No. 019-30685-00018, issued on November 3, 2011; and
(d) Significant Permit Modification No. 019-30719-00018, issued on December 5, 2011.

County Attainment Status

The source is located in Clark 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 23, 2001, for the 1-hour ozone standard for the Louisville area, including Clark County, and is a maintenance area for the 1-hour ozone National Ambient Air Quality Standard (NAAQS) for purposes of 40 CFR Part 51, Subpart X*. The 1-hour standard was revoked effective June 15, 2005.

Basic nonattainment designation effective federally April 5, 2005 for PM2.5.

(a) Ozone Standards
Volatile organic compounds (VOC) and Nitrogen Oxides (NO_x) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NO_x emissions are considered when evaluating the rule applicability relating to ozone. Clark County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NO_x emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) $PM_{2.5}$
Clark County has been classified as nonattainment for $PM_{2.5}$ in 70 FR 943 dated January 5, 2005. On May 8, 2008, U.S. EPA promulgated specific New Source Review rules for $PM_{2.5}$ emissions. These rules became effective on July 15, 2008. Therefore, direct $PM_{2.5}$ and SO_2 emissions were reviewed pursuant to the requirements of Nonattainment New Source Review, 326 IAC 2-1.1-5. See the State Rule Applicability – Entire Source section.

(c) Clark County has been classified as attainment or unclassifiable for PM_{10}, SO_2, NO_2, CO, and Lead. 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 chemical process 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 Proposed Modification

The Office of Air Quality (OAQ) has reviewed a modification application, submitted by PQ Corporation on November 21, 2011, to revise permit conditions related to the use of biodiesel in the two (2) fire tube boilers (SG-1001 and SG-1002) and the melting furnace. IDEM reviewed this request under Part 70 Operating Permit Renewal No. T019-23178-00018; however, additional permit conditions are required to allow these units to operate using biodiesel. This significant modification to the Part 70 Operating Permit Renewal incorporates the applicable permit conditions to allow PQ Corporation to use biodiesel.

Enforcement Issues

There are no pending enforcement actions.

Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

Permit Level Determination – Part 70

Pursuant to 326 IAC 2-1.1-1(16), 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.”

This modification is not subject to the source modification requirements under 326 IAC 2-7-10.5. The changes will be incorporated into the permit as a significant permit modification under 326 IAC 2-7-12(d)(1); because, the modification does not qualify as a minor permit modification or as an administrative amendment.

Permit Level Determination – PSD and Emission Offset

This modification to an existing minor stationary source is not major because the emissions increase is less than the PSD major source thresholds. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

This modification to an existing minor stationary source is not major because the emissions increase is less than the Nonattainment NSR major levels. Therefore, pursuant to 326 IAC 2-1.1-5, the Nonattainment NSR requirements do not apply.

Federal Rule Applicability Determination

NSPS:

(a) There are no New Source Performance Standards (NSPS)(326 IAC 12 and 40 CFR Part 60) included with this modification.

NESHAP:

(b) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14, 326 IAC 20 and 40 CFR Part 63) included with this modification.

CAM:

(c) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to new or modified emission units that involve a pollutant-specific emission unit and meet the following criteria:

(1) has a potential to emit before controls equal to or greater than the Part 70 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 potential to emit of PM, PM10, PM2.5, SO2, VOC, CO, NOx, GHGs and HAPs from the boilers and the melting furnace are all below the Part 70 major source thresholds and no control devices are used. Therefore, 40 CFR 64 does not apply to these emission units.

State Rule Applicability Determination

326 IAC 2-1.1-5 (Nonattainment New Source Review)

Nonattainment New Source Review applicability is discussed under the Permit Level Determination – PSD and Emission Offset section.

326 IAC 2-2 and 2-3 (PSD and Emission Offset)

PSD and Emission Offset applicability is discussed under the Permit Level Determination – PSD and Emission Offset section.

326 IAC 6.5 (Particulate Matter Limitations Except Lake County)

PQ Corporation is specially listed in 326 IAC 6.5-2, has potential particulate matter emissions in excess of 100 TPY and has actual particulate matter emissions of 10 TPY or more; therefore, the requirements of 326 IAC 6.5 apply. The following emission limitations apply:

(a) Pursuant to 326 IAC 6.5-1-2(b)(2) (Nonattainment Area Particulate Limitations for Fossil Fuel Fired Steam Generators; Liquid Fuel) and 326 IAC 6.5-1-2(b)(3) (Nonattainment Area Particulate Limitations for Fossil Fuel Fired Steam Generators; Gaseous Fuel), particulate matter emissions from the boilers (SG-1001 and SG-1002) shall be limited to 0.15 pounds per million Btu heat input when fuel oil is burned and 0.01 grains per dry standard cubic foot when natural gas is burned.

(b) Pursuant to 326 IAC 6.5-1-2(a) (Particulate Emission Limitations), the particulate matter emissions from the dryer shall be limited to 0.03 grains per dry standard cubic foot.

(c) Pursuant to 326 IAC 6.5-2-9 (PQ Corporation), the particulate matter emissions from the furnace shall be limited to 51.8 tons per year and 1.4 pounds per ton of sodium silicate produced.

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations
This source is located in Clark County, Jeffersonville Township, but does not have potential fugitive particulate matter emissions of 25 TPY or more. Therefore, this source is not subject to the requirements of 326 IAC 6-5.

326 IAC 7-1.1-1 (Sulfur Dioxide Rules)
This rule applies to emission units with the potential to emit sulfur dioxide in excess of 25 TPY. The melting furnace and boilers SG-1001 and SG-1002 are subject to this rule. The following emission limitations apply:

(a) Pursuant to 326 IAC 7-1.1 (SO_2 Emissions Limitations) the SO_2 emissions from the two (2) 17.5 MMBtu/hr oil-fired boilers (SG-1001 and SG-1002) shall not exceed five tenths (0.5) pound per million British thermal units heat input while combusting any fuel oil.

(b) Pursuant to 326 IAC 7-1.1 (SO_2 Emissions Limitations), the SO_2 emissions from the melting furnace shall not exceed five-tenths (0.5) pound per million Btu heat input while combusting any fuel oil.

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 requirements related to this modification are shown in the table below:

Summary of Testing Requirements						
Emission Unit	**Test condition**	**Control Device**	**Timeframe for Testing**	**Pollutant**	**Frequency of Testing**	**Limit or Requirement**
Melting Furnace	While Combusting Biodiesel	None	Within 180 days after usage of biodiesel	SO2	One Time	0.50 lb/MMBtu
				NOx	One Time	14.42 lb/hr
Boiler SG-1001	While Combusting Biodiesel	None	Within 180 days after usage of biodiesel	SO2	One Time	0.50 lb/MMBtu
				NOx	One Time	20 lb/Kgal

Compliance Monitoring Requirements
There are no changes to the Compliance Monitoring Requirements as a result of this modification.

Proposed Changes

The changes listed below have been made to Part 70 Operating Permit No. T019-23178-00018. Deleted language appears as ~~strikethroughs~~ and new language appears in **bold**:

Change No. 1 IDEM revised the emission unit description of the melting furnace to indicate biodiesel/No.2 fuel oil can be combusted in the unit. Revisions are shown below:

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(15)]

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

****

(c) One (1) melting furnace with a maximum heat input capacity of 19.7 MMBtu per hour, fired by natural gas or fuel oil, and exhausting at stack S-1. The furnace is fired using natural gas, with No. 2 fuel oil and No. 4 fuel oil**, biodiesel/No.2 fuel or any combination of the aforementioned fuel oils as secondary fuels**~~as a backup fuel~~. The furnace was constructed in 1938 and rebuilt in 1998 and 2003 pursuant to Administrative Amendment 019-16660-00018 issued on February 11, 2003.

****

Change No. 2 IDEM revised the emission unit description box in Section D.1 to update the emission unit description of the melting furnace. Revisions are shown below:

Emissions Unit Description:

(a) **********

(c) One (1) melting furnace with a maximum heat input capacity of 19.7 MMBtu per hour, fired by natural gas or fuel oil, and exhausting at stack S-1. The furnace is fired using natural gas, with No. 2 fuel oil and No. 4 fuel oil**, biodiesel/No.2 fuel or any combination of the aforementioned fuel oils as secondary fuels**~~as a backup fuel~~. The furnace was constructed in 1938 and rebuilt in 1998 and 2003 pursuant to Administrative Amendment 019-16660-00018 issued on February 11, 2003. **********

Change No. 3 IDEM revised Condition D.1.4 to include biodiesel/No.2 fuel oil to the list of possible fuels used by this source. Revisions are shown below:

D.1.4 PSD Minor Limit [326 IAC 2-2]

The input of natural gas to the furnace and furnace natural gas equivalents shall be limited to 180 MMscf per twelve (12) consecutive month period. NO_x emissions from the furnace shall not exceed 1,091 lbs/MMscf when burning natural gas and 102 lbs/kgal when burning No. 2 fuel oil, No. 4 fuel oil or a blend of No. 2 and No. 4 fuel oils**, biodiesel/No.2 fuel or any combination of the aforementioned fuel oils**. For purposes of determining compliance:

(a) Every gallon of No.2 fuel oil, No. 4 fuel oil or combination of No.2 and No. 4 fuel oils**, biodiesel/No.2 fuel or any combination of the aforementioned fuel oils** burned in the furnace shall be equivalent to 93.5 cubic feet of natural gas based on nitrogen oxides emissions.

****

Change No. 4 IDEM revised Condition D.1.5 to clarify the emission limits apply when any fuel oil is combusted in accordance with 326 IAC 7-2-1. The reference to 326 IAC 7-2-1 was removed. In accordance with 326 IAC 7-2-1(d)(2), the Permittee shall use a calendar month average SO2 emission rate in lb/MMBtu. Revisions are shown below

D.1.5 Sulfur Dioxide (SO_2) [326 IAC 7-1.1-1][326 IAC 7-2-1]

(a) Pursuant to 326 IAC 7-1.1 (SO_2 Emissions Limitations) the SO_2 emissions from the two (2) 17.5 MMBtu/hr oil-fired boilers (SG-1001 and SG-1002) shall not exceed five tenths (0.5) pound per million British thermal units heat input **while combusting any fuel oil**. Pursuant to 326 IAC 7-2-1**(d)(2)**, compliance shall be ~~demonstrated on a thirty (30) day rolling weighted average~~**determined using a calendar month average sulfur dioxide emission rate in pounds per MMBtu**.

(b) Pursuant to 326 IAC 7-1.1 (SO_2 Emissions Limitations), the SO_2 emissions from the melting furnace shall not exceed five-tenths (0.5) pound per million Btu heat input while combusting **any** fuel oil. Pursuant to 326 IAC 7-2-1**(d)(2)**, compliance shall be ~~demonstrated on a thirty (30) day rolling weighted average~~**determined using a calendar month average sulfur dioxide emission rate in pounds per MMBtu**.

Change No. 5 IDEM revised Condition D.1.9 to clarify the permit conditions apply to the emission limitations listed in Condition D.1.5 and effect the boilers and the melting furnace. Revisions are shown below:

D.1.9 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3-7-4]

Compliance **with the sulfur dioxide limits in Condition D.1.5(a) and D.1.5(b) for** ~~of~~ the two (2) boilers **and melting furnace** shall be determined utilizing one of the following options.

(a) **********

(b) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions ~~from the two (2) 17.5 MMBtu/hr boilers~~, using 40 CFR 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6.

Change No. 6 IDEM revised Condition D.1.7 to indicate testing is required to demonstrate the compliance status with Conditions D.1.4 and D.1.5. A requirement to test the melting furnace was also added because the melting furnace shows nonstandard combustion emissions. Revisions are shown below:

D.1.7 Testing Requirements [326 IAC 2-7-6(1),(6)]

In order to demonstrate the compliance status with Condition D.1.4 and Condition D.1.5, and n~~N~~ot later than 180 days after the initial usage of biodiesel as fuel in **the melting furnace or** boiler**s** SG-100**1** or SG-1002, the Permittee shall perform a one time stack test, to verify the NOx and SO2 emission factors used to determine the potential emissions from one of the boilers **and the melting furnace** while combusting biodiesel utilizing methods approved by the commissioner. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

Change No. 7 IDEM is correcting the cover sheet of the permit to show the actual street address of the source. The source is located at the intersection of 7th Street and Missouri Avenue in Jeffersonville with a street address of 1101 Quartz Road, Clarksville, Indiana 47129. All other addresses in the permit are correct.

Change No. 8 IDEM is revising the emission unit description of the fire tube boilers, identified as SG-1001 and SG-1002, to indicate the units are subject to 40 CFR 60, Subpart Dc. Section A.2(a), the facility description box in Section D.1 and the facility description box in Section E.1 are effected by this change. Revisions are shown below:

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(15)]

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

(a) Two (2) fire tube boilers (SG-1001 and SG-1002), constructed in 1991, each rated at seventeen and five-tenths (17.5) million British thermal units (MMBtu) per hour and exhausting at one (1) stack, identified as S-2. The boilers are fired by natural gas, No. 2 fuel oil and No. 4 fuel oil or biodiesel as a backup fuel. **[40 CFR 60, Subpart Dc]**

****

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) Two (2) fire tube boilers (SG-1001 and SG-1002), constructed in 1991, each rated at seventeen and five-tenths (17.5) million British thermal units (MMBtu) per hour and exhausting at one (1) stack, identified as S-2. The boilers are fired by natural gas, No. 2 fuel oil and No.4 fuel or biodiesel as a backup fuel. **[40 CFR 60, Subpart Dc]**

(b) **********

SECTION E.1 Standard of Performance for Industrial-Commercial-Institutional Steam Generating Units Requirements

Emission Unit Description:

(a) Two (2) fire tube boilers (SG-1001 and SG-1002), constructed in 1991, each rated at seventeen and five-tenths (17.5) million British thermal units (MMBtu) per hour and exhausting at one (1) stack, identified as S-2. The boilers are fired by natural gas, No. 2 fuel oil and No.4 fuel or biodiesel as a backup fuel. **[40 CFR 60, Subpart Dc]**

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

Change No. 9 The reporting form to show compliance with the PSD minor limit for NOx was revised to more closely match the actual permit condition. Furnace natural gas and furnace natural gas equivalents were added because natural gas combustion in the furnace includes process emissions. Natural gas combustion in the other units do not have process emissions. Revisions are shown below:

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

Part 70 Quarterly Report

Source Name:	PQ Corporation
Source Address:	1101 Quartz Road, Clarksville, IN 47129
Part 70 Permit No.:	T019-23178-00018
Facility:	Melting Furnace exhausting at S-1, Boilers SG-1001 & SG-1002, and Natural Gas Dryer exhausting at S-6
Parameter:	NO_X
Limit:	180 MMCF of ~~natural gas (or fuel oil equivalent)~~ **furnace natural gas or furnace natural gas equivalents** per twelve (12) consecutive month period.

****

Change No. 10 326 IAC 1-5 (Episode Alert Levels) applies to source with the potential to emit 100 tons per year or greater of VOC. This source does not have a potential to emit of 100 tons per year or more of VOC. Therefore, 326 IAC 1-5 does not apply. Original Condition C.11 has been deleted and all remaining conditions have been renumbered to account for the deletion. The condition deleted is shown below:

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

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

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

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

Change No. 11 Original Condition B.11(b)(4) was revised to include the southwest regional office to the notification list. Revisions are shown below:

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

(a) **********

(b) **********

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ, or Southeast Regional Office no later than four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance and Enforcement Branch), or
Telephone Number: 317-233-0178 (ask for Office of Air Quality, Compliance and Enforcement Branch)
Facsimile Number: 317-233-6865
Southeast Regional Office phone: (812) 358-2027; fax: (812) 358-2058
Southwest Regional Office phone: (812) 380-2305; fax: (812) 380-2304

Change No. 12 Original Condition D.1.11(a)(2) was revised to clarify the meaning of fuel oil. Revisions are shown below:

D.1.11 Record Keeping Requirements

(a) To document the compliance status with Condition D.1.4, the Permittee shall maintain records in accordance with (1) through (6) below. Note that pursuant to 40 CFR 60 Subpart Dc, the fuel oil sulfur limit applies at all times including periods of startup, shutdown, and malfunction.

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

(2) Actual fuel oil **(No. 2, No. 4, biodiesel or a combination of the aforementioned)** and natural gas usage since last compliance determination period and equivalent sulfur dioxide and NO_X emissions;

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Change No. 13 40 CFR 60, Subpart Dc was updated on January 20, 2011. Existing Attachment A, which contains the complete text of Subpart Dc, was removed and the new version of Subpart Dc was added. Revisions are shown below:

~~Attachment A: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units [40 CFR 60, Subpart Dc]~~

~~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_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.~~

~~*Process heater* means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.~~

~~*Residual oil* means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17).~~

~~*Steam generating unit* means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.~~

~~*Steam generating unit operating day* means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.~~

~~*Wet flue gas desulfurization technology* means an SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.~~

~~*Wet scrubber system* means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2.~~

~~*Wood* means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.~~

~~[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]~~

~~§ 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_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.~~

~~(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that:~~

~~(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:~~

~~(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_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:~~

$$\cancel{E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}}$$

~~Where:~~

~~E_s= SO_2 emission limit, expressed in ng/J or lb/MMBtu heat input;~~

~~K_a= 520 ng/J (1.2 lb/MMBtu);~~

~~K_b= 260 ng/J (0.60 lb/MMBtu);~~

~~K_c= 215 ng/J (0.50 lb/MMBtu);~~

~~H_a= Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];~~

~~H_b= Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and~~

~~H_c= Heat input from the combustion of oil, in J (MMBtu).~~

~~(f) Reduction in the potential SO_2 emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:~~

~~(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO_2 emission rate; and~~

~~(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO_2 control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.~~

~~(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.~~

~~(h) For affected facilities listed under paragraphs (h)(1), (2), 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_2 emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.~~

~~(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.~~

~~[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009]~~

~~§ 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_2 emissions is not subject to the PM limit in this section.~~

~~[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]~~

~~§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.~~

~~(a) Except as provided in paragraphs (g) and (h) of this section and §60.8(b), performance tests required under §60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.~~

~~(b) The initial performance test required under §60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO_2 emission limits under §60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.~~

~~(c) After the initial performance test required under paragraph (b) of this section and §60.8, compliance with the percent reduction requirements and SO_2 emission limits under §60.42c is based on the average percent reduction and the average SO_2 emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO_2 emission rate are calculated to show compliance with the standard.~~

~~(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average SO_2 emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B of appendix A of this part.~~

~~(e) If coal, oil, or coal and oil are combusted with other fuels:~~

~~(1) An adjusted E_{ho}(E_{ho}o) is used in Equation 19–19 of Method 19 of appendix A of this part to compute the adjusted E_{ao}(E_{ao}o). The E_{ho}o is computed using the following formula:~~

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

~~Where:~~

~~E_{ho}o = Adjusted E_{ho}, ng/J (lb/MMBtu);~~

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

~~E_w= SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value~~

~~E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume E_w = 0.~~

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

~~(2) The owner or operator of an affected facility that qualifies under the provisions of §60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters E_w or X_k if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.~~

~~(f) Affected facilities subject to the percent reduction requirements under §60.42c(a) or (b) shall determine compliance with the SO_2 emission limits under §60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:~~

~~(1) If only coal is combusted, the percent of potential SO_2 emission rate is computed using the following formula:~~

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

~~Where:~~

~~$\%P_s$ = Potential SO_2 emission rate, in percent;~~

~~$\%R_g$ = SO_2 removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and~~

~~$\%R_f$ = SO_2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.~~

~~(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:~~

~~(i) To compute the $\%P_s$, an adjusted $\%R_g$ ($\%R_g$o) is computed from E_{ao}o from paragraph (e)(1) of this section and an adjusted average SO_2 inlet rate (E_{ai}o) using the following formula:~~

$$\%R_g o = 100\left(1 - \frac{E^{\circ}_{ao}}{E^{\circ}_{ai}}\right)$$

~~Where:~~

~~$\%R_g$o = Adjusted $\%R_g$, in percent;~~

~~E_{ao}o = Adjusted E_{ao}, ng/J (lb/MMBtu); and~~

~~E_{ai}o = Adjusted average SO_2 inlet rate, ng/J (lb/MMBtu).~~

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

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

~~Where:~~

~~$E_{hi}o$ = Adjusted E_{hi}, ng/J (lb/MMBtu);~~

~~E_{hi}= Hourly SO_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) After July 1, 2010 or after Method 202 of appendix M of part 51 has been revised to minimize artifact measurement and notice of that change has been published in theFederal Register,whichever is later, for condensable PM emissions, Method 202 of appendix M of part 51 shall be used; and~~

~~(iii) 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]~~

~~§ 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_2 concentrations and either O_2 or CO_2 concentrations at both the inlet and outlet of the SO_2 control device.~~

~~(b) The 1-hour average SO_2 emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.42c. Each 1-hour average SO_2 emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under §60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.~~

~~(c) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.~~

~~(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.~~

~~(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.~~

~~(3) For affected facilities subject to the percent reduction requirements under §60.42c, the span value of the SO_2 CEMS at the inlet to the SO_2 control device shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted, and the span value of the SO_2 CEMS at the outlet from the SO_2 control device shall be 50 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.~~

~~(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c, the span value of the SO_2 CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.~~

~~(d) As an alternative to operating a CEMS at the inlet to the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.~~

~~(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate.~~

~~(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.~~

~~(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO_2 at the inlet or outlet of the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in §3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).~~

~~(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, as described under §60.48c(f), as applicable.~~

~~(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.~~

~~§ 60.47c Emission monitoring for particulate matter.~~

~~(a) Except as provided in paragraphs (c), (d), (e), (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) and that is not required to install a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to install 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 and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. If during the initial 60 minutes of observation all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent, the observation period may be reduced from 3 hours to 60 minutes.~~

~~(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 30 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 30 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]~~

~~§ 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_2emissions. 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]~~

Indiana Department of Environmental Management
Office of Air Quality

Attachment A

40 CFR 60, Subpart Dc — Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Source Description and Location

Source Name:	**PQ Corporation**
Source Location:	**1101 Quartz Road, Clarksville, Indiana 47129**
County:	**Clark County**
SIC Code:	**2819**
Operation Permit No.:	**T 019-23178-00018**
Permit Reviewer:	**David J. Matousek**

Complete Text of 40 CFR 60, Subpart Dc

40 CFR 60, 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:

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

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_2 emission limits under §60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:
(1) If only coal is combusted, the percent of potential SO_2 emission rate is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:
$\%P_s$= Potential SO_2 emission rate, in percent;
$\%R_g$= SO_2 removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and
$\%R_f$= SO_2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.
(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:
(i) To compute the $\%P_s$, an adjusted $\%R_g$ ($\%R_g o$) is computed from $E_{ao}o$ from paragraph (e)(1) of this section and an adjusted average SO_2 inlet rate ($E_{ai}o$) using the following formula:

$$\%R_g o = 100\left(1 - \frac{E^o_{ao}}{E^o_{ai}}\right)$$

Where:
$\%R_g o$ = Adjusted $\%R_g$, in percent;
$E_{ao}o$ = Adjusted E_{ao}, ng/J (lb/MMBtu); and
$E_{ai}o$ = Adjusted average SO_2 inlet rate, ng/J (lb/MMBtu).
(ii) To compute $E_{ai}o$, an adjusted hourly SO_2 inlet rate ($E_{hi}o$) is used. The $E_{hi}o$ is computed using the following formula:

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

Where:
$E_{hi}o$ = Adjusted E_{hi}, ng/J (lb/MMBtu);
E_{hi}= Hourly SO_2 inlet rate, ng/J (lb/MMBtu);
E_w= SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume E_w= 0; and
X_k= Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.
(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under §60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under §60.46c(d)(2).
(h) For affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in §60.48c(f), as applicable.
(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under §60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent

demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.
(j) The owner or operator of an affected facility shall use all valid SO_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.

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§ 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_2emissions. 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]

Conclusion and Recommendation

The construction of this proposed modification shall be subject to the conditions of the attached proposed Part 70 Significant Permit Modification. The staff recommend to the Commissioner that this Part 70 Significant Permit Modification be approved.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to David Matousek 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) 232-8253 or toll free at 1-800-451-6027 extension 2-8253.

(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

Technical Support Document - Appendix A - Emission Calculations
Emissions Summary

Company Name: PQ Corporation
Address: 1101 Quartz Road, Clarksville, Indiana 47129
Permit Number: 019-31174-00018
Reviewer: David J. Matousek
Date: December 9, 2011

Permit Level Determination - 326 IAC 2-7-10.5

PTE Prior to Project

Emission Unit	PM	PM10	PM2.5	SO2	VOC	CO	NOx	GHG (CO2e)		Single HAP	Total HAP
								Biogenic	Non-Biogenic		
Melting Furnace	25.33	24.53	23.61	95.83	3.07	7.11	113.81	0.00	14,324	0.15	0.15
Boiler SG-1001	3.58	4.24	4.24	38.87	0.41	6.31	10.95	0.00	12,722	0.14	0.15
Boiler SG-1002	3.58	4.24	4.24	38.87	0.41	6.31	10.95	0.00	12,722	0.14	0.15
Dryer	0.10	0.34	0.34	0.03	0.48	3.61	6.22	0.00	6,119	0.08	0.08
Total Prior Modification	32.59	33.35	32.43	173.60	4.38	23.34	141.93	0.00	45,887	0.51	0.53

PTE After to Project

Emission Unit	PM	PM10	PM2.5	SO2	VOC	CO	NOx	GHG (CO2e)		Single HAP	Total HAP
								Biogenic	Non-Biogenic		
Melting Furnace	25.33	24.53	23.61	95.83	3.07	7.11	113.81	0.00	14,324	0.15	0.15
Boiler SG-1001	3.58	4.24	4.24	38.87	0.41	6.31	10.95	0.00	12,722	0.14	0.15
Boiler SG-1002	3.58	4.24	4.24	38.87	0.41	6.31	10.95	0.00	12,722	0.14	0.15
Dryer	0.10	0.34	0.34	0.03	0.48	3.61	6.22	0.00	6,119	0.08	0.08
Total Prior Modification	32.59	33.35	32.43	173.60	4.38	23.34	141.93	0.00	45,887	0.51	0.53
Increase from Modification	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Permit Level Determination - 326 IAC 2-2

PTE (TPY)

Emission Unit	PM	PM10	PM2.5	SO2	VOC	CO	NOx	GHG (CO2e)	
								Biogenic	Non-Biogenic
Total for Modification	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0	0
Sourcewide Prior Modification*	59.92	59.58	58.83	< 100	4.38	15.18	< 100	0	45,887
Sourcewide After Modification	59.92	59.58	58.83	< 100	4.38	15.18	< 100	0	45,887
Major Source Threshold	100	100	---	100	100	100	100	---	100,000
Nonattainment NSR Major Source Threshold	---	---	100	---	---	---	---	---	---

Notes:
* Source wide emissions were taken from the TSD for SSM 019-30685-00018 for all pollutants except VOC and GHGs. VOC and GHG emissions were recalculated for all combustion sources as part of this permit modification.

Technical Support Document - Appendix A - Emission Calculations
PTE Calculation Before and After Modification

Company Name: PQ Corporation
Address: 1101 Quartz Road, Clarksville, Indiana 47129
Permit Number: 019-31174-00018
Reviewer: David J. Matousek
Date: December 9, 2011

Change in the Potential to Emit - Melting Furnace

Pollutant	Process Emissions	Combustion Emissions				Process + Combustion Emissions				PTE After Mod.	PTE Prior Mod.
	Material Melting	Natural Gas	No. 2 Fuel Oil	No. 4 Fuel Oil	Biodiesel	Natural Gas	No. 2 Fuel Oil	No. 4 Fuel Oil	Biodiesel		
PM	21.30	0.16	1.23	4.03	1.05	21.46	22.53	25.33	22.35	25.33	25.33
PM10	19.75	0.64	2.03	4.78	1.72	20.39	21.78	24.53	21.47	24.53	24.53
PM2.5	18.83	0.64	2.03	4.78	1.72	19.47	20.86	23.61	20.55	23.61	23.61
SO2	52.07	0.05	43.76	43.14	36.13	52.12	95.83	95.21	88.20	95.83	95.83
NOx	101.48	8.46	12.33	11.50	11.82	109.94	113.81	112.98	113.30	113.81	113.81
VOC	2.60	0.47	0.12	0.12	0.22	3.07	2.72	2.72	2.82	3.07	3.07
CO	0.00	7.11	3.08	2.88	2.54	7.11	3.08	2.88	2.54	7.11	7.11
Biogenic GHG (CO2e)	0.00	0.00	0.00	0.00	14,105	0.00	0.00	0.00	14,105	14,464	0.00
Non-Biogenic GHG (CO2e)	0.00	10,096	14,115	14,324	0.00	10,096	14,115	14,324	0.00	14,324	14,324
Hexane	0.00	0.15	0.00	0.00	0.00	0.15	0.00	0.00	0.00	0.15	0.15
Formaldehyde	0.00	0.01	0.02	0.02	0.06	0.01	0.02	0.02	0.06	0.06	0.02
Acetaldehyde	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.05	0.05	0.00
Worst Case Single HAP	0.00	Hexane				Hexane				0.15	0.15
Total HAP	0.00	0.15	0.03	0.03	0.12	0.15	0.03	0.03	0.12	0.15	0.15

Technical Support Document - Appendix A - Emission Calculations
PTE Calculation Before and After Modification (Continued)

Change in the Potential to Emit - Boilers SG-1001 and SG-1002 - Each Unit

Pollutant	Combustion Emissions				PTE After Mod.	PTE Prior Mod.
	Natural Gas	No. 2 Fuel Oil	No. 4 Fuel Oil	Biodiesel		
PM	0.14	1.10	3.58	0.92	3.58	3.58
PM10	0.57	1.81	4.24	1.53	4.24	4.24
PM2.5	0.57	1.81	4.24	1.53	4.24	4.24
SO2	0.05	38.87	38.33	32.09	38.87	38.87
NOx	7.51	10.95	10.22	10.50	10.95	10.95
VOC	0.41	0.11	0.10	0.19	0.41	0.41
CO	6.31	2.74	2.56	2.26	6.31	6.31
Biogenic GHG (CO2e)	0.00	0.00	0.00	12,530	Exempt	
Non-Biogenic GHG (CO2e)	8,968	12,540	12,722	0.00	12,722	12,722
Hexane	0.14	0.00	0.00	0.00	0.14	0.14
Formaldehyde	0.01	0.02	0.02	0.04	0.04	0.02
Acetaldehyde	0.00	0.00	0.00	0.05	0.05	0.00
Worst Case Single HAP	Hexane				0.14	0.14
Total HAP	0.15	0.03	0.02	0.11	0.15	0.15

Potential to Emit - Dryer - No Changes Proposed

Pollutant	Combustion Emissions		PTE After Mod.	PTE Prior Mod.
	Natural Gas	Propane		
PM	0.08	0.10	0.10	0.10
PM10	0.33	0.34	0.34	0.34
PM2.5	0.33	0.34	0.34	0.34
SO2	0.03	5.74E-04	0.03	0.03
NOx	4.29	6.22	6.22	6.22
VOC	0.24	0.48	0.48	0.48
CO	3.61	3.59	3.61	3.61
Biogenic GHG (CO2e)	0.00	0.00	0.00	0.00
Non-Biogenic GHG (CO2e)	5,125	6,119	6,119	6,119
Worst Case Single HAP	0.08	0.00	0.08	0.08
Total HAP	0.08	0.00	0.08	0.08

Technical Support Document - Appendix A - Emission Calculations
Combustion Emissions - Melting Furnace Process Emissions

Company Name: PQ Corporation
Address: 1101 Quartz Road, Clarksville, Indiana 47129
Permit Number: 019-31174-00018
Reviewer: David J. Matousek
Date: December 9, 2011

Natural Gas Requirements

Heat Input (MMBtu/hr)	19.70	MMBtu/hr
Heat Input (MMBtu/yr)	172,572	MMBtu/yr
Heat Content	1,020	MMBtu/MMCF
Annual Usage	169.19	MMCF/yr
Glass Melting Rate	3.50	ton/hr

Combined Emissions (Combustion and Process)

Pollutant	Emission Factor (lb/ton)	PTE (TPY)	Emission Factor Notes
PM	1.40	21.46	AP-42, Chapter 11.15, Table 11.15-1, 10/86
PM10	1.33	20.39	95% of PM, AP-42, Chapter 11.15, Table 11.15-3, 10/86
PM2.5	1.27	19.47	91% of PM, AP-42, Chapter 11.15, Table 11.15-3, 10/86
SO2	3.40	52.12	AP-42, Chapter 11.15, Table 11.15-1, 10/86
NOx	7.17	109.94	Stack Test - Sept 1998 and Feb 1999 (25.1 lb NOx/hr @ 3.5 ton/hr)
VOC	0.20	3.07	AP-42, Chapter 11.15, Table 11.15-2, 10/86
CO	0.20	3.07	AP-42, Chapter 11.15, Table 11.15-2, 10/86

Emissions from Natual Gas Combustion

Pollutant	Emission Factor (lb/MMCF)	PTE (TPY)	Emission Factor Notes
PM (Filterable)	1.90	0.16	AP-42, Chapter 1.4, 7/98, Table 1.4-2
PM (Condensible)	5.70	0.48	AP-42, Chapter 1.4, 7/98, Table 1.4-2
PM	1.90	0.16	AP-42, Chapter 1.4, 7/98, Table 1.4-2
PM10	7.60	0.64	AP-42, Chapter 1.4, 7/98, Table 1.4-2
PM2.5	7.60	0.64	AP-42, Chapter 1.4, 7/98, Table 1.4-2
SO2	0.60	0.05	AP-42, Chapter 1.4, 7/98, Table 1.4-2
NOx	100.00	8.46	AP-42, Chapter 1.4, 7/98, Table 1.4-1
VOC	5.50	0.47	AP-42, Chapter 1.4, 7/98, Table 1.4-2
CO	84.00	7.11	AP-42, Chapter 1.4, 7/98, Table 1.4-1
Hexane	1.80	0.15	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Formaldehyde	0.075	0.01	AP-42, Chapter 1.4, 7/98, Table 1.4-3
CO2	119,226	10,086	Kg/MMBtu converted to lb/MMCF, 40 CFR 98, Subpart C
CH4	2.25	0.19	Kg/MMBtu converted to lb/MMCF, 40 CFR 98, Subpart C
N2O	0.22	0.02	Kg/MMBtu converted to lb/MMCF, 40 CFR 98, Subpart C
Biogenic GHGs as CO2e	---	0.00	Global Warming Potentials, CO2 = 1, CH4 = 21, N20 = 310
Nonbiogenic GHG as CO2e	---	10,096	Global Warming Potentials, CO2 = 1, CH4 = 21, N20 = 310

Process Emissions = Combined less Combustion Emissions

Pollutant	Combined Emissions (TPY)	Combustion Emissions (TPY)	Process Emissions (TPY)	
PM	21.46	0.16	21.30	
PM10	20.39	0.64	19.75	
PM2.5	19.47	0.64	18.83	
SO2	52.12	0.05	52.07	
NOx	109.94	8.46	101.48	
VOC	3.07	0.47	2.60	
CO	3.07	7.11	0.00	**(Assume All CO is from Combustion)**

Technical Support Document - Appendix A - Emission Calculations
Furnace Combustion Emissions - No. 2 Fuel Oil

Company Name: PQ Corporation
Address: 1101 Quartz Road, Clarksville, Indiana 47129
Permit Number: 019-31174-00018
Reviewer: David J. Matousek
Date: December 9, 2011

Fuel Oil Requirements

Heat Input (MMBtu/hr)	19.70	MMBtu/hr		
Heat Input (MMBtu/yr)	172,572	MMBtu/yr		
Allowable Sulfur Content	0.50%			
Heating Value	140,000	Btu/gallon		
Fuel Oil Required	1,232,657	gallons/yr	1,232.657	kgal/yr

Non-HAP Emissions

Pollutant	Emission Factor (lb/kgal)	PTE (TPY)	Emission Factor Notes
PM (Filterable)	2.00	1.23	AP-42, Chapter 1.3, Table 1.3-1, 5/10
PM (Condensible)	1.30	0.80	AP-42, Chapter 1.3, Table 1.3-2, 5/10
PM	2.00	1.23	Filterable PM Only
PM10	3.30	2.03	Filterable and Condensible PM
PM2.5	3.30	2.03	PM10 = PM2.5
SO2	71.00	43.76	AP-42, Chapter 1.3, Table 1.3-1, 5/10, S = 0.5
NOx	20.00	12.33	AP-42, Chapter 1.3, Table 1.3-1, 5/10
VOC	0.20	0.12	AP-42, Chapter 1.3, Table 1.3-3, 5/10
CO	5.00	3.08	AP-42, Chapter 1.3, Table 1.3-1, 5/10
CO2	22,827	14,069	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
CH4	0.93	0.57	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
N2O	0.19	0.11	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
Biogenic (CO2e)	---	0.00	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310
Non-Biogenic (CO2e)	---	14,115	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310

Organic HAP Emissions			
Pollutant	**Emission Factor (lb/kgal)**	**PTE (TPY)**	**Emission Factor Notes**
Benzene	2.14E-04	1.32E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Ethylbenzene	6.36E-05	3.92E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Formaldehyde	3.30E-02	2.03E-02	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Naphthalene	1.13E-03	6.96E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
1,1,1-Trichloroethane	2.36E-04	1.45E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Toluene	6.20E-03	3.82E-03	AP-42, Chapter 1.3, 5/10, Table 1.3-9
O-Xylene	1.09E-04	6.72E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Acenaphthene	2.11E-05	1.30E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Acenaphthylene	2.53E-07	1.56E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Anthracene	1.22E-06	7.52E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benz(a)anthracene	4.01E-06	2.47E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benzo(b,k)fluoranthene	1.48E-06	9.12E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benzo(g,h,i)perylene	2.26E-06	1.39E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Chrysene	2.38E-06	1.47E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Dibenzo(a,h)anthracene	1.67E-06	1.03E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Fluoranthene	4.48E-06	2.76E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Fluorene	4.47E-06	2.75E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Indo(1,2,3-cd)pyrene	2.14E-06	1.32E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Phenanthrene	1.05E-05	6.47E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Pyrene	4.25E-06	2.62E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Dixoins	3.10E-09	1.91E-09	AP-42, Chapter 1.3, 5/10, Table 1.3-9

Inorganic HAP Emissions			
Pollutant	**Emission Factor (lb/MMBtu)**	**PTE (TPY)**	**Emission Factor Notes**
As	4.00E-06	3.45E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Be	3.00E-06	2.59E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Cd	3.00E-06	2.59E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Cr	3.00E-06	2.59E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Pb	9.00E-06	7.77E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Hg	3.00E-06	2.59E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Mn	6.00E-06	5.18E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Ni	3.00E-06	2.59E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Se	1.50E-05	1.29E-03	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Total HAP		**0.03**	
Single HAP		**0.02**	**(Formaldehyde)**

Technical Support Document - Appendix A - Emission Calculations
Furnace Combustion Emissions - No. 4 Fuel Oil

Company Name: PQ Corporation
Address: 1101 Quartz Road, Clarksville, Indiana 47129
Permit Number: 019-31174-00018
Reviewer: David J. Matousek
Date: December 9, 2011

Fuel Oil Requirements

Theat Input (MMBtu/hr)	19.70	MMBtu/hr		
Total Heat Input Needed	172,572	MMBtu/yr		
Allowable Sulfur Content	0.50%			
Heating Value	150,000	Btu/gallon		
Fuel Oil Required	1,150,480	gallons/yr	1,150.480	kgal/yr

Non-HAP Emissions

Pollutant	Emission Factor (lb/kgal)	PTE (TPY)	Emission Factor Notes
PM (Filterable)	7.00	4.03	AP-42, Chapter 1.3, Table 1.3-1, 5/10
PM (Condensible)	1.30	0.75	AP-42, Chapter 1.3, Table 1.3-2, 5/10
PM	7.00	4.03	Filterable PM Only
PM10	8.30	4.78	Filterable and Condensible PM
PM2.5	8.30	4.78	PM10 = PM2.5
SO2	75.00	43.14	AP-42, Chapter 1.3, Table 1.3-1, 5/10, S = 0.5
NOx	20.00	11.50	AP-42, Chapter 1.3, Table 1.3-1, 5/10
VOC	0.20	0.12	AP-42, Chapter 1.3, Table 1.3-3, 5/10
CO	5.00	2.88	AP-42, Chapter 1.3, Table 1.3-1, 5/10
CO2	24,815	14,275	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
CH4	0.99	0.57	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
N2O	0.20	0.12	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
Biogenic (CO2e)	---	0.00	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310
Non-Biogenic (CO2e)	---	14,324	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310

Organic HAP Emissions			
Pollutant	**Emission Factor (lb/kgal)**	**PTE (TPY)**	**Emission Factor Notes**
Benzene	2.14E-04	1.23E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Ethylbenzene	6.36E-05	3.66E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Formaldehyde	3.30E-02	1.90E-02	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Naphthalene	1.13E-03	6.50E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
1,1,1-Trichloroethane	2.36E-04	1.36E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Toluene	6.20E-03	3.57E-03	AP-42, Chapter 1.3, 5/10, Table 1.3-9
O-Xylene	1.09E-04	6.27E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Acenaphthene	2.11E-05	1.21E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Acenaphthylene	2.53E-07	1.46E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Anthracene	1.22E-06	7.02E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benz(a)anthracene	4.01E-06	2.31E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benzo(b,k)fluoranthene	1.48E-06	8.51E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benzo(g,h,i)perylene	2.26E-06	1.30E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Chrysene	2.38E-06	1.37E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Dibenzo(a,h)anthracene	1.67E-06	9.61E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Fluoranthene	4.48E-06	2.58E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Fluorene	4.47E-06	2.57E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Indo(1,2,3-cd)pyrene	2.14E-06	1.23E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Phenanthrene	1.05E-05	6.04E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Pyrene	4.25E-06	2.44E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Dixoins	3.10E-09	1.78E-09	AP-42, Chapter 1.3, 5/10, Table 1.3-9

Inorganic HAP Emissions			
Pollutant	**Emission Factor (lb/MMBtu)**	**PTE (TPY)**	**Emission Factor Notes**
As	4.00E-06	3.45E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Be	3.00E-06	2.59E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Cd	3.00E-06	2.59E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Cr	3.00E-06	2.59E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Pb	9.00E-06	7.77E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Hg	3.00E-06	2.59E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Mn	6.00E-06	5.18E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Ni	3.00E-06	2.59E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Se	1.50E-05	1.29E-03	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Total HAP		**0.03**	
Single HAP		**0.02**	**(Formaldehyde)**

Technical Support Document - Appendix A - Emission Calculations
Furnace Combustion - Biodiesel / No. 2 Blend

Company Name: PQ Corporation
Address: 1101 Quartz Road, Clarksville, Indiana 47129
Permit Number: 019-31174-00018
Reviewer: David J. Matousek
Date: December 9, 2011

Fuel Oil Requirements

Maximum Heat Input	19.7	MMBtu/hr		
Maximum Heat Input	172,572	MMBtu/yr		
Sulfur Content	0.50%			
% Biodiesel	20.00%			
Biodiesel Heating Value	135,660	Btu/gallon	(Volume Average)	
Biodiesel at PTE	1,272.09	kgal/yr	172,572	MMBtu/yr
No. 2 at PTE	1,017.67	kgal/yr	142,474	MMBtu/yr
B100 at PTE	254.42	kgal/yr	30,098	MMBtu/yr

Notes:
1) Specific Gravity = 0.88 (No. 2 and B100)
2) Heat Capacity No. 2 = 140,000 Btu/gallon
3) Heat Capacity B100 = 118,300 Btu/gallon
4) CO2 emissions from biodiesel are considered biogenic.

Emissions from No. 2 Fuel Oil Combustion

Non-HAP Emissions

Pollutant	Emission Factor (lb/kgal)	PTE (TPY)	Emission Factor Notes
PM (Filterable)	2.00	1.02	AP-42, Chapter 1.3, Table 1.3-1, 5/10
PM (Condensible)	1.30	0.66	AP-42, Chapter 1.3, Table 1.3-2, 5/10
PM	2.00	1.02	Filterable PM Only
PM10	3.30	1.68	Filterable and Condensible PM
PM2.5	3.30	1.68	PM10 = PM2.5
SO2	71.00	36.13	AP-42, Chapter 1.3, Table 1.3-1, 5/10, S = 0.5
NOx	20.00	10.18	AP-42, Chapter 1.3, Table 1.3-1, 5/10
VOC	0.20	0.10	AP-42, Chapter 1.3, Table 1.3-3, 5/10
CO	5.00	2.54	AP-42, Chapter 1.3, Table 1.3-1, 5/10
CO2	22,827	11,615	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
CH4	0.93	0.47	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
N2O	0.19	0.09	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
Biogenic (CO2e)	---	11,653	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310
Non-Biogenic (CO2e)	---	0	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310

Organic HAP Emissions

Pollutant	Emission Factor (lb/kgal)	PTE (TPY)	Emission Factor Notes
Benzene	2.14E-04	1.09E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Ethylbenzene	6.36E-05	3.24E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Formaldehyde	3.30E-02	1.68E-02	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Naphthalene	1.13E-03	5.75E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
1,1,1-Trichloroethane	2.36E-04	1.20E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Toluene	6.20E-03	3.15E-03	AP-42, Chapter 1.3, 5/10, Table 1.3-9
O-Xylene	1.09E-04	5.55E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Acenaphthene	2.11E-05	1.07E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Acenaphthylene	2.53E-07	1.29E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Anthracene	1.22E-06	6.21E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benz(a)anthracene	4.01E-06	2.04E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benzo(b,k)fluoranthene	1.48E-06	7.53E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benzo(g,h,i)perylene	2.26E-06	1.15E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Chrysene	2.38E-06	1.21E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Dibenzo(a,h)anthracene	1.67E-06	8.50E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Fluoranthene	4.48E-06	2.28E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Fluorene	4.47E-06	2.27E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Indo(1,2,3-cd)pyrene	2.14E-06	1.09E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Phenanthrene	1.05E-05	5.34E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Pyrene	4.25E-06	2.16E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Dixoins	3.10E-09	1.58E-09	AP-42, Chapter 1.3, 5/10, Table 1.3-9

Inorganic HAP Emissions			
Pollutant	**Emission Factor (lb/MMBtu)**	**PTE (TPY)**	**Emission Factor Notes**
As	4.00E-06	2.85E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Be	3.00E-06	2.14E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Cd	3.00E-06	2.14E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Cr	3.00E-06	2.14E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Pb	9.00E-06	6.41E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Hg	3.00E-06	2.14E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Mn	6.00E-06	4.27E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Ni	3.00E-06	2.14E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Se	1.50E-05	1.07E-03	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Total HAP		**0.02**	
Single HAP		**0.02**	**(Formaldehyde)**

Emissions from B100 Biodiesel Combustion

Non-VOC and Non-HAP Emissions			
Pollutant	**Emission Factor (lb/MMBtu)**	**PTE (TPY)**	**Emission Factor Notes**
PM (Filterable)	1.81E-03	0.03	EPA/600/R-08/069, September 2008, Table 7
PM (Condensible)	1.10E-03	0.02	EPA/600/R-08/069, September 2008, Table 7
PM	1.81E-03	0.03	Filterable PM Only
PM10	2.91E-03	0.04	Filterable and Condensible PM Only
PM2.5	2.91E-03	0.04	PM10 = PM2.5
SO2	4.62E-09	6.95E-08	EPA/600/R-08/069, September 2008, Table 6
NOx	1.09E-01	1.64	Emission Factors for Priority Biofuels in Minnesota, Table 4-6
CO	3.14E-09	4.73E-08	EPA/600/R-08/069, September 2008, Table 6
CO2	162.79	2,450	Converted to lb/MMBtu, 40 CFR 98, Subpart C
CH4	2.43E-03	0.04	Converted to lb/MMBtu, 40 CFR 98, Subpart C
N2O	2.43E-04	3.66E-03	Converted to lb/MMBtu, 40 CFR 98, Subpart C
Biogenic (CO2e)	---	2,452	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310
Non-Biogenic (CO2e)	---	0	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310

VOC Emissions			
Pollutant	**Emission Factor (lb/MMBtu)**	**PTE (TPY)**	**Emission Factor Notes**
Formaldehyde	3.08E-03	0.05	EPA/600/R-08/069, September 2008, Table 10
Acetaldehyde	3.38E-03	0.05	EPA/600/R-08/069, September 2008, Table 10
Bromomethane	3.12E-06	4.70E-05	EPA/600/R-08/069, September 2008, Table 13
Chloroethane	1.94E-06	2.92E-05	EPA/600/R-08/069, September 2008, Table 13
Ethanol	2.64E-04	3.97E-03	EPA/600/R-08/069, September 2008, Table 13
Carbon Disulfide	4.52E-04	6.80E-03	EPA/600/R-08/069, September 2008, Table 13
Isopropyl Alcohol	1.42E-05	2.14E-04	EPA/600/R-08/069, September 2008, Table 13
Vinyl Acetate	7.07E-06	1.06E-04	EPA/600/R-08/069, September 2008, Table 13
Cyclohexane	1.19E-05	1.79E-04	EPA/600/R-08/069, September 2008, Table 13
Chloroform	4.06E-06	6.11E-05	EPA/600/R-08/069, September 2008, Table 13
Ethyl Acetate	1.23E-05	1.85E-04	EPA/600/R-08/069, September 2008, Table 13
Tetrahydrofuran	1.21E-05	1.82E-04	EPA/600/R-08/069, September 2008, Table 13
2-Butanone	2.81E-05	4.23E-04	EPA/600/R-08/069, September 2008, Table 13
Benzene	4.53E-05	6.82E-04	EPA/600/R-08/069, September 2008, Table 13
Trichloroethylene	1.12E-05	1.69E-04	EPA/600/R-08/069, September 2008, Table 13
Toluene	1.08E-05	1.63E-04	EPA/600/R-08/069, September 2008, Table 13
4-Methyl-2-Pentanone	5.02E-06	7.55E-05	EPA/600/R-08/069, September 2008, Table 13
Ethylbenzene	4.18E-06	6.29E-05	EPA/600/R-08/069, September 2008, Table 13
Chlorobenzene	7.31E-06	1.10E-04	EPA/600/R-08/069, September 2008, Table 13

VOC Emissions (Continued)			
Pollutant	**Emission Factor (lb/MMBtu)**	**PTE (TPY)**	**Emission Factor Notes**
m,p-xylene	9.15E-06	1.38E-04	EPA/600/R-08/069, September 2008, Table 13
o-xylene	3.26E-06	4.91E-05	EPA/600/R-08/069, September 2008, Table 13
Styrene	2.25E-06	3.39E-05	EPA/600/R-08/069, September 2008, Table 13
Tribromomethane	1.44E-05	2.17E-04	EPA/600/R-08/069, September 2008, Table 13
1,1,2,2-Tetrachloroethane	5.27E-06	7.93E-05	EPA/600/R-08/069, September 2008, Table 13
Naphthalene	2.12E-07	3.19E-06	EPA/600/R-08/069, September 2008, Table 17
2-Methylnapthalene	1.24E-07	1.87E-06	EPA/600/R-08/069, September 2008, Table 17
Acenaphthylene	2.63E-08	3.96E-07	EPA/600/R-08/069, September 2008, Table 17
Acenaphthene	2.63E-09	3.96E-08	EPA/600/R-08/069, September 2008, Table 17
Phenanthrene	1.85E-06	2.78E-05	EPA/600/R-08/069, September 2008, Table 17
Anthracene	1.66E-08	2.50E-07	EPA/600/R-08/069, September 2008, Table 17
Fluoranthene	2.53E-07	3.81E-06	EPA/600/R-08/069, September 2008, Table 17
Pyrene	1.21E-07	1.82E-06	EPA/600/R-08/069, September 2008, Table 17
Benzo(a)anthracene	3.38E-09	5.09E-08	EPA/600/R-08/069, September 2008, Table 17
Chrysene	8.52E-09	1.28E-07	EPA/600/R-08/069, September 2008, Table 17
Benzo(b)fluoranthene	5.27E-09	7.93E-08	EPA/600/R-08/069, September 2008, Table 17
Benzo(k)fluoranthene	1.41E-09	2.12E-08	EPA/600/R-08/069, September 2008, Table 17
Benzo(e)pyrene	2.85E-09	4.29E-08	EPA/600/R-08/069, September 2008, Table 17
Benzo(a)pyrene	1.08E-09	1.63E-08	EPA/600/R-08/069, September 2008, Table 17
Ideno(1,2,3-cd)pyrene	1.24E-09	1.87E-08	EPA/600/R-08/069, September 2008, Table 17
Benzo(g,h,i)perylene	3.86E-09	5.81E-08	EPA/600/R-08/069, September 2008, Table 17
Total PCB's	2.67E-04	4.02E-03	EPA/600/R-08/069, September 2008, Table 20
Total VOC Emissions		**0.12**	

HAP Emissions			
Pollutant	**Emission Factor (lb/kgal)**	**PTE (TPY)**	**Emission Factor Notes**
Formaldehyde	---	0.05	Use VOC Emission Factor
Acetaldehyde	---	0.05	Use VOC Emission Factor
Bromomethane	3.12E-06	3.97E-07	EPA/600/R-08/069, September 2008, Table 13
Chloroethane	1.94E-06	2.47E-07	EPA/600/R-08/069, September 2008, Table 13
Carbon Disulfide	4.52E-04	5.75E-05	EPA/600/R-08/069, September 2008, Table 13
Vinyl Acetate	7.07E-06	8.99E-07	EPA/600/R-08/069, September 2008, Table 13
Chloroform	4.06E-06	5.16E-07	EPA/600/R-08/069, September 2008, Table 13
Benzene	4.53E-05	5.76E-06	EPA/600/R-08/069, September 2008, Table 13
Trichloroethylene	1.12E-05	1.42E-06	EPA/600/R-08/069, September 2008, Table 13
Toluene	1.08E-05	1.37E-06	EPA/600/R-08/069, September 2008, Table 13
4-Methyl-2-Pentanone	5.02E-06	6.39E-07	EPA/600/R-08/069, September 2008, Table 13
Ethylbenzene	4.18E-06	5.32E-07	EPA/600/R-08/069, September 2008, Table 13
Chlorobenzene	7.31E-06	9.30E-07	EPA/600/R-08/069, September 2008, Table 13
m,p-xylene	9.15E-06	1.16E-06	EPA/600/R-08/069, September 2008, Table 13
o-xylene	3.26E-06	4.15E-07	EPA/600/R-08/069, September 2008, Table 13
Styrene	2.25E-06	2.86E-07	EPA/600/R-08/069, September 2008, Table 13
Tribromomethane	1.44E-05	1.83E-06	EPA/600/R-08/069, September 2008, Table 13
1,1,2,2-Tetrachloroethane	5.27E-06	6.70E-07	EPA/600/R-08/069, September 2008, Table 13
Naphthalene	2.12E-07	2.70E-08	EPA/600/R-08/069, September 2008, Table 17
2-Methylnapthalene	1.24E-07	1.58E-08	EPA/600/R-08/069, September 2008, Table 17
Acenaphthylene	2.63E-08	3.35E-09	EPA/600/R-08/069, September 2008, Table 17
Acenaphthene	2.63E-09	3.35E-10	EPA/600/R-08/069, September 2008, Table 17
Phenanthrene	1.85E-06	2.35E-07	EPA/600/R-08/069, September 2008, Table 17
Anthracene	1.66E-08	2.11E-09	EPA/600/R-08/069, September 2008, Table 17
Fluoranthene	2.53E-07	3.22E-08	EPA/600/R-08/069, September 2008, Table 17
Pyrene	1.21E-07	1.54E-08	EPA/600/R-08/069, September 2008, Table 17
Benzo(a)anthracene	3.38E-09	4.30E-10	EPA/600/R-08/069, September 2008, Table 17
Chrysene	8.52E-09	1.08E-09	EPA/600/R-08/069, September 2008, Table 17
Benzo(b)fluoranthene	5.27E-09	6.70E-10	EPA/600/R-08/069, September 2008, Table 17
Benzo(k)fluoranthene	1.41E-09	1.79E-10	EPA/600/R-08/069, September 2008, Table 17
Benzo(e)pyrene	2.85E-09	3.63E-10	EPA/600/R-08/069, September 2008, Table 17
Benzo(a)pyrene	1.08E-09	1.37E-10	EPA/600/R-08/069, September 2008, Table 17
Ideno(1,2,3-cd)pyrene	1.24E-09	1.58E-10	EPA/600/R-08/069, September 2008, Table 17
Benzo(g,h,i)perylene	3.86E-09	4.91E-10	EPA/600/R-08/069, September 2008, Table 17
Total PCB's	2.67E-04	3.40E-05	EPA/600/R-08/069, September 2008, Table 20
Total HAP Emissions		**0.10**	
Single HAP		**0.05**	**(Acetaldehyde)**

Estimated Emissions from Biodiesel Blend

Potential to Emit			
Pollutant	**No. 2 (TPY)**	**B100 (TPY)**	**Biodiesel Blend (TPY)**
PM	1.02	0.03	1.05
PM10	1.68	0.04	1.72
PM2.5	1.68	0.04	1.72
SO2	36.13	6.95E-08	36.13
NOx	10.18	1.64	11.82
CO	2.54	4.73E-08	2.54
VOC	0.10	0.12	0.22
Biogenic GHG as CO2e	11,653	2,452	14,105
Non-Biogenic GHG as CO2e	0	0	0
Formaldehyde	0.017	0.0464	0.063
Acetaldehyde	0	0.0509	0.051
Worst Case Single HAP	Formaldehyde		0.06
Total HAP	0.02	9.73E-02	0.12

Technical Support Document - Appendix A - Emission Calculations
Boiler SG-1001/1002 Combustion Emissions - Natural Gas

Company Name: PQ Corporation
Address: 1101 Quartz Road, Clarksville, Indiana 47129
Permit Number: 019-31174-00018
Reviewer: David J. Matousek
Date: December 9, 2011

Natural Gas Requirements - Each Boiler

Heat Input (MMBtu/hr)	17.50	MMBtu/hr
Heat Input (MMBtu/yr)	153,300	MMBtu/yr
Heat Content	1,020	MMBtu/MMCF
Annual Usage	150.29	MMCF/yr

Non-HAP Emissions - Each Boiler

Pollutant	Emission Factor (lb/MMCF)	PTE (TPY)	Emission Factor Notes
PM (Filterable)	1.90	0.14	AP-42, Chapter 1.4, 7/98, Table 1.4-2
PM (Condensible)	5.70	0.43	AP-42, Chapter 1.4, 7/98, Table 1.4-2
PM	1.90	0.14	AP-42, Chapter 1.4, 7/98, Table 1.4-2
PM10	7.60	0.57	AP-42, Chapter 1.4, 7/98, Table 1.4-2
PM2.5	7.60	0.57	AP-42, Chapter 1.4, 7/98, Table 1.4-2
SO2	0.60	0.05	AP-42, Chapter 1.4, 7/98, Table 1.4-2
NOx	100.00	7.51	AP-42, Chapter 1.4, 7/98, Table 1.4-1
VOC	5.50	0.41	AP-42, Chapter 1.4, 7/98, Table 1.4-2
CO	84.00	6.31	AP-42, Chapter 1.4, 7/98, Table 1.4-1
CO2	119,226	8,959	Kg/MMBtu converted to lb/MMCF, 40 CFR 98, Subpart C
CH4	2.25	0.17	Kg/MMBtu converted to lb/MMCF, 40 CFR 98, Subpart C
N2O	0.22	0.02	Kg/MMBtu converted to lb/MMCF, 40 CFR 98, Subpart C
Biogenic (CO2e)	---	0.00	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310
Non-Biogenic (CO2e)	---	8,968	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310

Organic HAP Emissions - Each Boiler

Pollutant	Emission Factor (lb/MMCF)	PTE (TPY)	Emission Factor Notes
2-Methylnaphthalene	2.40E-05	1.80E-06	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Benzene	0.0021	1.58E-04	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Dichlorobenzene	0.0012	9.02E-05	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Fluoranthene	3.00E-06	2.25E-07	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Fluorene	2.80E-06	2.10E-07	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Formaldehyde	0.0750	0.01	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Hexane	1.8000	0.14	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Naphthalene	6.10E-04	4.58E-05	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Phenanathrene	1.70E-05	1.28E-06	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Pyrene	5.00E-06	3.76E-07	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Toluene	3.40E-03	2.55E-04	AP-42, Chapter 1.4, 7/98, Table 1.4-3

Inorganic HAP Emissions - Each Boiler

Pollutant	Emission Factor (lb/MMCF)	PTE (TPY)	Emission Factor Notes
As	2.00E-04	1.50E-05	AP-42, Chapter 1.4, 7/98, Table 1.4-4
Cd	1.10E-03	8.27E-05	AP-42, Chapter 1.4, 7/98, Table 1.4-4
Cr	1.40E-03	1.05E-04	AP-42, Chapter 1.4, 7/98, Table 1.4-4
Co	8.40E-05	6.31E-06	AP-42, Chapter 1.4, 7/98, Table 1.4-4
Hg	2.60E-04	1.95E-05	AP-42, Chapter 1.4, 7/98, Table 1.4-4
Mn	3.80E-04	2.86E-05	AP-42, Chapter 1.4, 7/98, Table 1.4-4
Ni	2.10E-03	1.58E-04	AP-42, Chapter 1.4, 7/98, Table 1.4-4
Total HAP		**0.15**	
Single HAP		**0.14**	**(Hexane)**

Technical Support Document - Appendix A - Emission Calculations
Boiler SG-1001/1002 Combustion Emissions - No. 2 Fuel Oil

Company Name: PQ Corporation
Address: 1101 Quartz Road, Clarksville, Indiana 47129
Permit Number: 019-31174-00018
Reviewer: David J. Matousek
Date: December 9, 2011

Fuel Oil Requirements - Each Boiler

Heat Input (MMBtu/hr)	17.50	MMBtu/hr			
Heat Input (MMBtu/yr)	153,300	MMBtu/yr			
Allowable Sulfur Content	0.50%				
Heating Value	140,000	Btu/gallon			
Fuel Oil Required	1,095,000	gallons/yr	or	1,095.000	kgal/yr

Non-HAP Emissions - Each Boiler

Pollutant	Emission Factor (lb/kgal)	PTE (TPY)	Emission Factor Notes
PM (Filterable)	2.00	1.10	AP-42, Chapter 1.3, Table 1.3-1, 5/10
PM (Condensible)	1.30	0.71	AP-42, Chapter 1.3, Table 1.3-2, 5/10
PM	2.00	1.10	Filterable PM Only
PM10	3.30	1.81	Filterable and Condensible PM
PM2.5	3.30	1.81	PM10 = PM2.5
SO2	71.00	38.87	AP-42, Chapter 1.3, Table 1.3-1, 5/10, S = 0.5
NOx	20.00	10.95	AP-42, Chapter 1.3, Table 1.3-1, 5/10
VOC	0.20	0.11	AP-42, Chapter 1.3, Table 1.3-3, 5/10
CO	5.00	2.74	AP-42, Chapter 1.3, Table 1.3-1, 5/10
CO2	22,827	12,498	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
CH4	0.93	0.51	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
N2O	0.19	0.10	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
Biogenic (CO2e)	---	0.00	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310
Non-Biogenic (CO2e)	---	12,540	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310

Organic HAP Emissions - Each Boiler			
Pollutant	**Emission Factor (lb/kgal)**	**PTE (TPY)**	**Emission Factor Notes**
Benzene	2.14E-04	1.17E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Ethylbenzene	6.36E-05	3.48E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Formaldehyde	3.30E-02	1.81E-02	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Naphthalene	1.13E-03	6.19E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
1,1,1-Trichloroethane	2.36E-04	1.29E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Toluene	6.20E-03	3.39E-03	AP-42, Chapter 1.3, 5/10, Table 1.3-9
O-Xylene	1.09E-04	5.97E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Acenaphthene	2.11E-05	1.16E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Acenaphthylene	2.53E-07	1.39E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Anthracene	1.22E-06	6.68E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benz(a)anthracene	4.01E-06	2.20E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benzo(b,k)fluoranthene	1.48E-06	8.10E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benzo(g,h,i)perylene	2.26E-06	1.24E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Chrysene	2.38E-06	1.30E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Dibenzo(a,h)anthracene	1.67E-06	9.14E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Fluoranthene	4.48E-06	2.45E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Fluorene	4.47E-06	2.45E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Indo(1,2,3-cd)pyrene	2.14E-06	1.17E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Phenanthrene	1.05E-05	5.75E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Pyrene	4.25E-06	2.33E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Dixoins	3.10E-09	1.70E-09	AP-42, Chapter 1.3, 5/10, Table 1.3-9

Inorganic HAP Emissions - Each Boiler			
Pollutant	**Emission Factor (lb/MMBtu)**	**PTE (TPY)**	**Emission Factor Notes**
As	4.00E-06	3.07E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Be	3.00E-06	2.30E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Cd	3.00E-06	2.30E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Cr	3.00E-06	2.30E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Pb	9.00E-06	6.90E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Hg	3.00E-06	2.30E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Mn	6.00E-06	4.60E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Ni	3.00E-06	2.30E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Se	1.50E-05	1.15E-03	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Total HAP		**0.03**	
Single HAP		**0.02**	**(Formaldehyde)**

Technical Support Document - Appendix A - Emission Calculations
Boiler SG-1001/1002 Combustion Emissions - No. 4 Fuel Oil

Company Name: PQ Corporation
Address: 1101 Quartz Road, Clarksville, Indiana 47129
Permit Number: 019-31174-00018
Reviewer: David J. Matousek
Date: December 9, 2011

Fuel Oil Requirements - Each Boiler

Theat Input (MMBtu/hr)	17.50	MMBtu/hr			
Total Heat Input Needed	153,300	MMBtu/yr			
Allowable Sulfur Content	0.50%				
Heating Value	150,000	Btu/gallon			
Fuel Oil Required	1,022,000	gallons/yr	or	1,022.000	kgal/yr

Non-HAP Emissions - Each Boiler

Pollutant	Emission Factor (lb/kgal)	PTE (TPY)	Emission Factor Notes
PM (Filterable)	7.00	3.58	AP-42, Chapter 1.3, Table 1.3-1, 5/10
PM (Condensible)	1.30	0.66	AP-42, Chapter 1.3, Table 1.3-2, 5/10
PM	7.00	3.58	Filterable PM Only
PM10	8.30	4.24	Filterable and Condensible PM
PM2.5	8.30	4.24	PM10 = PM2.5
SO2	75.00	38.33	AP-42, Chapter 1.3, Table 1.3-1, 5/10, S = 0.5
NOx	20.00	10.22	AP-42, Chapter 1.3, Table 1.3-1, 5/10
VOC	0.20	0.10	AP-42, Chapter 1.3, Table 1.3-3, 5/10
CO	5.00	2.56	AP-42, Chapter 1.3, Table 1.3-1, 5/10
CO2	24,815	12,680	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
CH4	0.99	0.51	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
N2O	0.20	0.10	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
Biogenic (CO2e)	---	0.00	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310
Non-Biogenic (CO2e)	---	12,722	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310

Organic HAP Emissions - Each Boiler			
Pollutant	**Emission Factor (lb/kgal)**	**PTE (TPY)**	**Emission Factor Notes**
Benzene	2.14E-04	1.09E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Ethylbenzene	6.36E-05	3.25E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Formaldehyde	3.30E-02	1.69E-02	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Naphthalene	1.13E-03	5.77E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
1,1,1-Trichloroethane	2.36E-04	1.21E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Toluene	6.20E-03	3.17E-03	AP-42, Chapter 1.3, 5/10, Table 1.3-9
O-Xylene	1.09E-04	5.57E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Acenaphthene	2.11E-05	1.08E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Acenaphthylene	2.53E-07	1.29E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Anthracene	1.22E-06	6.23E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benz(a)anthracene	4.01E-06	2.05E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benzo(b,k)fluoranthene	1.48E-06	7.56E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benzo(g,h,i)perylene	2.26E-06	1.15E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Chrysene	2.38E-06	1.22E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Dibenzo(a,h)anthracene	1.67E-06	8.53E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Fluoranthene	4.48E-06	2.29E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Fluorene	4.47E-06	2.28E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Indo(1,2,3-cd)pyrene	2.14E-06	1.09E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Phenanthrene	1.05E-05	5.37E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Pyrene	4.25E-06	2.17E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Dixoins	3.10E-09	1.58E-09	AP-42, Chapter 1.3, 5/10, Table 1.3-9

Inorganic HAP Emissions - Each Boiler			
Pollutant	**Emission Factor (lb/MMBtu)**	**PTE (TPY)**	**Emission Factor Notes**
As	4.00E-06	3.07E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Be	3.00E-06	2.30E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Cd	3.00E-06	2.30E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Cr	3.00E-06	2.30E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Pb	9.00E-06	6.90E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Hg	3.00E-06	2.30E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Mn	6.00E-06	4.60E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Ni	3.00E-06	2.30E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Se	1.50E-05	1.15E-03	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Total HAP		**0.02**	
Single HAP		**0.02**	**(Formaldehyde)**

Technical Support Document - Appendix A - Emission Calculations
Boiler SG-1001/1002 Combustion Emissions - Biodiesel / No. 2 Blend

Company Name: PQ Corporation
Address: 1101 Quartz Road, Clarksville, Indiana 47129
Permit Number: 019-31174-00018
Reviewer: David J. Matousek
Date: December 9, 2011

Fuel Oil Requirements - Each Boiler

Maximum Heat Input	17.5	MMBtu/hr		
Maximum Heat Input	153,300	MMBtu/yr		
Sulfur Content	0.50%			
% Biodiesel	20.00%			
Biodiesel Heating Value	135,660	Btu/gallon	(Volume Average)	
Biodiesel at PTE	1,130.03	kgal/yr	153,300	MMBtu/yr
No.2 at PTE	904.02	kgal/yr	126,563	MMBtu/yr
B100 at PTE	226.01	kgal/yr	26,737	MMBtu/yr

Notes:
1) Specific Gravity = 0.88 (No. 2 and B100)
2) Heat Capacity No. 2 = 140,000 Btu/gallon
3) Heat Capacity B100 = 118,300 Btu/gallon
4) CO2 emissions from biodiesel are considered biogenic.

Emissions from No. 2 Fuel Oil Combustion - Each Boiler

Non-HAP Emissions

Pollutant	Emission Factor (lb/kgal)	PTE (TPY)	Emission Factor Notes
PM (Filterable)	2.00	0.90	AP-42, Chapter 1.3, Table 1.3-1, 5/10
PM (Condensible)	1.30	0.59	AP-42, Chapter 1.3, Table 1.3-2, 5/10
PM	2.00	0.90	Filterable PM Only
PM10	3.30	1.49	Filterable and Condensible PM
PM2.5	3.30	1.49	PM10 = PM2.5
SO2	71.00	32.09	AP-42, Chapter 1.3, Table 1.3-1, 5/10, S = 0.5
NOx	20.00	9.04	AP-42, Chapter 1.3, Table 1.3-1, 5/10
VOC	0.20	0.09	AP-42, Chapter 1.3, Table 1.3-3, 5/10
CO	5.00	2.26	AP-42, Chapter 1.3, Table 1.3-1, 5/10
CO2	22,827	10,318	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
CH4	0.93	0.42	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
N2O	0.19	0.08	Kg/MMBtu converted to lb/kgal, 40 CFR 98, Subpart C
Biogenic (CO2e)	---	10,352	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310
Non-Biogenic (CO2e)	---	0	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310

Organic HAP Emissions - Each Boiler

Pollutant	Emission Factor (lb/kgal)	PTE (TPY)	Emission Factor Notes
Benzene	2.14E-04	9.67E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Ethylbenzene	6.36E-05	2.87E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Formaldehyde	3.30E-02	1.49E-02	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Naphthalene	1.13E-03	5.11E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
1,1,1-Trichloroethane	2.36E-04	1.07E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Toluene	6.20E-03	2.80E-03	AP-42, Chapter 1.3, 5/10, Table 1.3-9
O-Xylene	1.09E-04	4.93E-05	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Acenaphthene	2.11E-05	9.54E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Acenaphthylene	2.53E-07	1.14E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Anthracene	1.22E-06	5.51E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benz(a)anthracene	4.01E-06	1.81E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benzo(b,k)fluoranthene	1.48E-06	6.69E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Benzo(g,h,i)perylene	2.26E-06	1.02E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Chrysene	2.38E-06	1.08E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Dibenzo(a,h)anthracene	1.67E-06	7.55E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Fluoranthene	4.48E-06	2.03E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Fluorene	4.47E-06	2.02E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Indo(1,2,3-cd)pyrene	2.14E-06	9.67E-07	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Phenanthrene	1.05E-05	4.75E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Pyrene	4.25E-06	1.92E-06	AP-42, Chapter 1.3, 5/10, Table 1.3-9
Dixoins	3.10E-09	1.40E-09	AP-42, Chapter 1.3, 5/10, Table 1.3-9

Inorganic HAP Emissions - Each Boiler			
Pollutant	**Emission Factor (lb/MMBtu)**	**PTE (TPY)**	**Emission Factor Notes**
As	4.00E-06	2.53E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Be	3.00E-06	1.90E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Cd	3.00E-06	1.90E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Cr	3.00E-06	1.90E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Pb	9.00E-06	5.70E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Hg	3.00E-06	1.90E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Mn	6.00E-06	3.80E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Ni	3.00E-06	1.90E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Se	1.50E-05	9.49E-04	AP-42, Chapter 1.3, 5/10, Table 1.3-10
Total HAP		**0.02**	
Single HAP		**0.01**	**(Formaldehyde)**

Emissions from B100 Biodiesel Combustion - Each Boiler

Non-VOC and Non-HAP Emissions			
Pollutant	**Emission Factor (lb/MMBtu)**	**PTE (TPY)**	**Emission Factor Notes**
PM (Filterable)	1.81E-03	0.02	EPA/600/R-08/069, September 2008, Table 7
PM (Condensible)	1.10E-03	0.01	EPA/600/R-08/069, September 2008, Table 7
PM	1.81E-03	0.02	Filterable PM Only
PM10	2.91E-03	0.04	Filterable and Condensible PM Only
PM2.5	2.91E-03	0.04	PM10 = PM2.5
SO2	4.62E-09	6.18E-08	EPA/600/R-08/069, September 2008, Table 6
NOx	1.09E-01	1.46	Emission Factors for Priority Biofuels in Minnesota, Table 4-6
CO	3.14E-09	4.20E-08	EPA/600/R-08/069, September 2008, Table 6
CO2	162.79	2,176	Converted to lb/MMBtu, 40 CFR 98, Subpart C
CH4	2.43E-03	0.03	Converted to lb/MMBtu, 40 CFR 98, Subpart C
N2O	2.43E-04	3.25E-03	Converted to lb/MMBtu, 40 CFR 98, Subpart C
Biogenic (CO2e)	---	2,178	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310
Non-Biogenic (CO2e)	---	0	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310

VOC Emissions - Each Boiler			
Pollutant	**Emission Factor (lb/MMBtu)**	**PTE (TPY)**	**Emission Factor Notes**
Formaldehyde	3.08E-03	0.04	EPA/600/R-08/069, September 2008, Table 10
Acetaldehyde	3.38E-03	0.05	EPA/600/R-08/069, September 2008, Table 10
Bromomethane	3.12E-06	4.17E-05	EPA/600/R-08/069, September 2008, Table 13
Chloroethane	1.94E-06	2.59E-05	EPA/600/R-08/069, September 2008, Table 13
Ethanol	2.64E-04	3.53E-03	EPA/600/R-08/069, September 2008, Table 13
Carbon Disulfide	4.52E-04	6.04E-03	EPA/600/R-08/069, September 2008, Table 13
Isopropyl Alcohol	1.42E-05	1.90E-04	EPA/600/R-08/069, September 2008, Table 13
Vinyl Acetate	7.07E-06	9.45E-05	EPA/600/R-08/069, September 2008, Table 13
Cyclohexane	1.19E-05	1.59E-04	EPA/600/R-08/069, September 2008, Table 13
Chloroform	4.06E-06	5.43E-05	EPA/600/R-08/069, September 2008, Table 13
Ethyl Acetate	1.23E-05	1.64E-04	EPA/600/R-08/069, September 2008, Table 13
Tetrahydrofuran	1.21E-05	1.62E-04	EPA/600/R-08/069, September 2008, Table 13
2-Butanone	2.81E-05	3.76E-04	EPA/600/R-08/069, September 2008, Table 13
Benzene	4.53E-05	6.06E-04	EPA/600/R-08/069, September 2008, Table 13
Trichloroethylene	1.12E-05	1.50E-04	EPA/600/R-08/069, September 2008, Table 13
Toluene	1.08E-05	1.44E-04	EPA/600/R-08/069, September 2008, Table 13
4-Methyl-2-Pentanone	5.02E-06	6.71E-05	EPA/600/R-08/069, September 2008, Table 13
Ethylbenzene	4.18E-06	5.59E-05	EPA/600/R-08/069, September 2008, Table 13
Chlorobenzene	7.31E-06	9.77E-05	EPA/600/R-08/069, September 2008, Table 13

VOC Emissions (Continued)			
Pollutant	**Emission Factor (lb/MMBtu)**	**PTE (TPY)**	**Emission Factor Notes**
m,p-xylene	9.15E-06	1.22E-04	EPA/600/R-08/069, September 2008, Table 13
o-xylene	3.26E-06	4.36E-05	EPA/600/R-08/069, September 2008, Table 13
Styrene	2.25E-06	3.01E-05	EPA/600/R-08/069, September 2008, Table 13
Tribromomethane	1.44E-05	1.93E-04	EPA/600/R-08/069, September 2008, Table 13
1,1,2,2-Tetrachloroethane	5.27E-06	7.05E-05	EPA/600/R-08/069, September 2008, Table 13
Naphthalene	2.12E-07	2.83E-06	EPA/600/R-08/069, September 2008, Table 17
2-Methylnapthalene	1.24E-07	1.66E-06	EPA/600/R-08/069, September 2008, Table 17
Acenaphthylene	2.63E-08	3.52E-07	EPA/600/R-08/069, September 2008, Table 17
Acenaphthene	2.63E-09	3.52E-08	EPA/600/R-08/069, September 2008, Table 17
Phenanthrene	1.85E-06	2.47E-05	EPA/600/R-08/069, September 2008, Table 17
Anthracene	1.66E-08	2.22E-07	EPA/600/R-08/069, September 2008, Table 17
Fluoranthene	2.53E-07	3.38E-06	EPA/600/R-08/069, September 2008, Table 17
Pyrene	1.21E-07	1.62E-06	EPA/600/R-08/069, September 2008, Table 17
Benzo(a)anthracene	3.38E-09	4.52E-08	EPA/600/R-08/069, September 2008, Table 17
Chrysene	8.52E-09	1.14E-07	EPA/600/R-08/069, September 2008, Table 17
Benzo(b)fluoranthene	5.27E-09	7.05E-08	EPA/600/R-08/069, September 2008, Table 17
Benzo(k)fluoranthene	1.41E-09	1.88E-08	EPA/600/R-08/069, September 2008, Table 17
Benzo(e)pyrene	2.85E-09	3.81E-08	EPA/600/R-08/069, September 2008, Table 17
Benzo(a)pyrene	1.08E-09	1.44E-08	EPA/600/R-08/069, September 2008, Table 17
Ideno(1,2,3-cd)pyrene	1.24E-09	1.66E-08	EPA/600/R-08/069, September 2008, Table 17
Benzo(g,h,i)perylene	3.86E-09	5.16E-08	EPA/600/R-08/069, September 2008, Table 17
Total PCB's	2.67E-04	3.57E-03	EPA/600/R-08/069, September 2008, Table 20
Total VOC Emissions		**0.10**	

HAP Emissions - Each Boiler			
Pollutant	**Emission Factor (lb/kgal)**	**PTE (TPY)**	**Emission Factor Notes**
Formaldehyde	---	0.04	Use VOC Emission Factor
Acetaldehyde	---	0.05	Use VOC Emission Factor
Bromomethane	3.12E-06	3.53E-07	EPA/600/R-08/069, September 2008, Table 13
Chloroethane	1.94E-06	2.19E-07	EPA/600/R-08/069, September 2008, Table 13
Carbon Disulfide	4.52E-04	5.11E-05	EPA/600/R-08/069, September 2008, Table 13
Vinyl Acetate	7.07E-06	7.99E-07	EPA/600/R-08/069, September 2008, Table 13
Chloroform	4.06E-06	4.59E-07	EPA/600/R-08/069, September 2008, Table 13
Benzene	4.53E-05	5.12E-06	EPA/600/R-08/069, September 2008, Table 13
Trichloroethylene	1.12E-05	1.27E-06	EPA/600/R-08/069, September 2008, Table 13
Toluene	1.08E-05	1.22E-06	EPA/600/R-08/069, September 2008, Table 13
4-Methyl-2-Pentanone	5.02E-06	5.67E-07	EPA/600/R-08/069, September 2008, Table 13
Ethylbenzene	4.18E-06	4.72E-07	EPA/600/R-08/069, September 2008, Table 13
Chlorobenzene	7.31E-06	8.26E-07	EPA/600/R-08/069, September 2008, Table 13
m,p-xylene	9.15E-06	1.03E-06	EPA/600/R-08/069, September 2008, Table 13
o-xylene	3.26E-06	3.68E-07	EPA/600/R-08/069, September 2008, Table 13
Styrene	2.25E-06	2.54E-07	EPA/600/R-08/069, September 2008, Table 13
Tribromomethane	1.44E-05	1.63E-06	EPA/600/R-08/069, September 2008, Table 13
1,1,2,2-Tetrachloroethane	5.27E-06	5.96E-07	EPA/600/R-08/069, September 2008, Table 13
Naphthalene	2.12E-07	2.40E-08	EPA/600/R-08/069, September 2008, Table 17
2-Methylnapthalene	1.24E-07	1.40E-08	EPA/600/R-08/069, September 2008, Table 17
Acenaphthylene	2.63E-08	2.97E-09	EPA/600/R-08/069, September 2008, Table 17
Acenaphthene	2.63E-09	2.97E-10	EPA/600/R-08/069, September 2008, Table 17
Phenanthrene	1.85E-06	2.09E-07	EPA/600/R-08/069, September 2008, Table 17
Anthracene	1.66E-08	1.88E-09	EPA/600/R-08/069, September 2008, Table 17
Fluoranthene	2.53E-07	2.86E-08	EPA/600/R-08/069, September 2008, Table 17
Pyrene	1.21E-07	1.37E-08	EPA/600/R-08/069, September 2008, Table 17
Benzo(a)anthracene	3.38E-09	3.82E-10	EPA/600/R-08/069, September 2008, Table 17
Chrysene	8.52E-09	9.63E-10	EPA/600/R-08/069, September 2008, Table 17
Benzo(b)fluoranthene	5.27E-09	5.96E-10	EPA/600/R-08/069, September 2008, Table 17
Benzo(k)fluoranthene	1.41E-09	1.59E-10	EPA/600/R-08/069, September 2008, Table 17
Benzo(e)pyrene	2.85E-09	3.22E-10	EPA/600/R-08/069, September 2008, Table 17
Benzo(a)pyrene	1.08E-09	1.22E-10	EPA/600/R-08/069, September 2008, Table 17
Ideno(1,2,3-cd)pyrene	1.24E-09	1.40E-10	EPA/600/R-08/069, September 2008, Table 17
Benzo(g,h,i)perylene	3.86E-09	4.36E-10	EPA/600/R-08/069, September 2008, Table 17
Total PCB's	2.67E-04	3.02E-05	EPA/600/R-08/069, September 2008, Table 20
Total HAP Emissions		**0.09**	
Single HAP		**0.05**	**(Acetaldehyde)**

Estimated Emissions from Biodiesel Blend - Each Boiler

Potential to Emit			
Pollutant	**No. 2 (TPY)**	**B100 (TPY)**	**Biodiesel Blend (TPY)**
PM	0.90	0.02	0.92
PM10	1.49	0.04	1.53
PM2.5	1.49	0.04	1.53
SO2	32.09	6.18E-08	32.09
NOx	9.04	1.46	10.50
VOC	0.09	0.10	0.19
CO	2.26	4.20E-08	2.26
Biogenic GHG as CO2e	10,352	2,178	12,530
Non-Biogenic GHG as CO2e	0	0	0
Formaldehyde	0.015	0.0412	0.056
Acetaldehyde	0	0.0452	0.045
Worst Case Single HAP	Formaldehyde		0.06
Total HAP	0.02	8.65E-02	0.11

Technical Support Document - Appendix A - Emission Calculations
Dryer Combustion Emissions - Propane - No Modification Proposed

Company Name: PQ Corporation
Address: 1101 Quartz Road, Clarksville, Indiana 47129
Permit Number: 019-31174-00018
Reviewer: David J. Matousek
Date: December 9, 2011

Propane Requirements

Heat Input (MMBtu/hr)	10.00	MMBtu/hr			
Heat Input (MMBtu/yr)	87,600	MMBtu/yr			
Allowable Sulfur Content	0.012%	(120 ppm)			
Heating Value	91,500	Btu/gallon			
Fuel Oil Required	957,377	gallons/yr	or	957.377	kgal/yr

Non-HAP Emissions

Pollutant	Emission Factor (lb/Kgal)	PTE (TPY)	Emission Factor Notes
PM (Filterable)	0.20	0.10	AP-42, Chapter 1.5, 7/08, Table 1.5-1
PM (Condensible)	0.50	0.24	AP-42, Chapter 1.5, 7/08, Table 1.5-1
PM	0.20	0.10	AP-42, Chapter 1.5, 7/08, Table 1.5-1
PM10	0.70	0.34	AP-42, Chapter 1.5, 7/08, Table 1.5-1
PM2.5	0.70	0.34	AP-42, Chapter 1.5, 7/08, Table 1.5-1
SO2	0.0012	5.74E-04	AP-42, Chapter 1.5, 7/08, Table 1.5-1, S = 0.012
NOx	13.00	6.22	AP-42, Chapter 1.5, 7/08, Table 1.5-1
VOC	1.00	0.48	AP-42, Chapter 1.5, 7/08, Table 1.5-1
CO	7.50	3.59	AP-42, Chapter 1.5, 7/08, Table 1.5-1
CO2	12,500	5,984	AP-42, Chapter 1.5, 7/08, Table 1.5-1
CH4	0.20	0.10	AP-42, Chapter 1.5, 7/08, Table 1.5-1
N2O	0.90	0.43	AP-42, Chapter 1.5, 7/08, Table 1.5-1
Biogenic (CO2e)	---	0.00	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310
Non-Biogenic (CO2e)	---	6,119	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310

Technical Support Document - Appendix A - Emission Calculations
Dryer Combustion Emissions - Natural Gas - No Modifications Proposed

Company Name: PQ Corporation
Address: 1101 Quartz Road, Clarksville, Indiana 47129
Permit Number: 019-31174-00018
Reviewer: David J. Matousek
Date: December 9, 2011

Natural Gas Requirements - Each Boiler

Heat Input (MMBtu/hr)	10.00	MMBtu/hr
Heat Input (MMBtu/yr)	87,600	MMBtu/yr
Heat Content	1,020	MMBtu/MMCF
Annual Usage	85.88	MMCF/yr

Non-HAP Emissions - Each Boiler

Pollutant	Emission Factor (lb/MMCF)	PTE (TPY)	Emission Factor Notes
PM (Filterable)	1.90	0.08	AP-42, Chapter 1.4, 7/98, Table 1.4-2
PM (Condensible)	5.70	0.24	AP-42, Chapter 1.4, 7/98, Table 1.4-2
PM	1.90	0.08	AP-42, Chapter 1.4, 7/98, Table 1.4-2
PM10	7.60	0.33	AP-42, Chapter 1.4, 7/98, Table 1.4-2
PM2.5	7.60	0.33	AP-42, Chapter 1.4, 7/98, Table 1.4-2
SO2	0.60	0.03	AP-42, Chapter 1.4, 7/98, Table 1.4-2
NOx	100.00	4.29	AP-42, Chapter 1.4, 7/98, Table 1.4-1
VOC	5.50	0.24	AP-42, Chapter 1.4, 7/98, Table 1.4-2
CO	84.00	3.61	AP-42, Chapter 1.4, 7/98, Table 1.4-1
CO2	119,226	5,120	Kg/MMBtu converted to lb/MMCF, 40 CFR 98, Subpart C
CH4	2.25	0.10	Kg/MMBtu converted to lb/MMCF, 40 CFR 98, Subpart C
N2O	0.22	0.01	Kg/MMBtu converted to lb/MMCF, 40 CFR 98, Subpart C
Biogenic (CO2e)	---	0.00	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310
Non-Biogenic (CO2e)	---	5,125	Global Warming Potentials, CO_2 = 1, CH_4 = 21, N_20 = 310

Organic HAP Emissions - Each Boiler

Pollutant	Emission Factor (lb/MMCF)	PTE (TPY)	Emission Factor Notes
2-Methylnaphthalene	2.40E-05	1.03E-06	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Benzene	0.0021	9.02E-05	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Dichlorobenzene	0.0012	5.15E-05	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Fluoranthene	3.00E-06	1.29E-07	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Fluorene	2.80E-06	1.20E-07	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Formaldehyde	0.0750	3.22E-03	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Hexane	1.8000	0.08	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Naphthalene	6.10E-04	2.62E-05	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Phenanathrene	1.70E-05	7.30E-07	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Pyrene	5.00E-06	2.15E-07	AP-42, Chapter 1.4, 7/98, Table 1.4-3
Toluene	3.40E-03	1.46E-04	AP-42, Chapter 1.4, 7/98, Table 1.4-3

Inorganic HAP Emissions - Each Boiler

Pollutant	Emission Factor (lb/MMCF)	PTE (TPY)	Emission Factor Notes
As	2.00E-04	8.59E-06	AP-42, Chapter 1.4, 7/98, Table 1.4-4
Cd	1.10E-03	4.72E-05	AP-42, Chapter 1.4, 7/98, Table 1.4-4
Cr	1.40E-03	6.01E-05	AP-42, Chapter 1.4, 7/98, Table 1.4-4
Co	8.40E-05	3.61E-06	AP-42, Chapter 1.4, 7/98, Table 1.4-4
Hg	2.60E-04	1.12E-05	AP-42, Chapter 1.4, 7/98, Table 1.4-4
Mn	3.80E-04	1.63E-05	AP-42, Chapter 1.4, 7/98, Table 1.4-4
Ni	2.10E-03	9.02E-05	AP-42, Chapter 1.4, 7/98, Table 1.4-4
Total HAP		**0.08**	
Single HAP		**0.08**	**(Hexane)**

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

100 North Senate Avenue
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TO: George A Monasky
PQ Corp
1101 Quartz Rd
Clarksville, IN 47129

DATE: April 13, 2012

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

SUBJECT: Final Decision
Title V
019 - 31174 - 00018

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

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

April 9, 2012

TO: Jeffersonville Public Library

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

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: PQ Corp
Permit Number: 019 - 31174 - 00018

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

Mail Code 61-53

IDEM Staff	DPABST 04/09/2012 PQ Corp 31174 (final)			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
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2		Larry Masaro Dir - N American Plant Ops PQ Corp 429 Kipling Ave Toronto ON M8Z-5C7 *(RO CAATS)*									
3		Ms. Rhonda England 17213 Persimmon Run Rd Borden IN 47106-8604 *(Affected Party)*									
4		Ms. Betty Hislip 602 Dartmouth Drive, Apt 8 Clarksville IN 47129 *(Affected Party)*									
5		Mrs. Sandy Banet 514 Haddox Rd Henryville IN 47126 *(Affected Party)*									
6		Jeffersonville City Council and Mayors Office 500 Quarter Master Jeffersonville IN 47130 *(Local Official)*									
7		Jeffersonville Twp Public Library 211 E Court Ave, P.O. Box 1548 Jeffersonville IN 47131-1548 *(Library)*									
8		Mr. Robert Bottom Paddlewheel Alliance P.O. Box 35531 Louisville KY 40232-5531 *(Affected Party)*									
9		Clark County Board of Commissioners 501 E. Court Avenue Jeffersonville IN 47130 *(Local Official)*									
10		Clark County Health Department 1320 Duncan Avenue Jeffersonville IN 47130-3723 *(Health Department)*									
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