State of Illinois
ENVIRONMENTAL PROTECTION AGENCY

Mary A. Gade, Director

2200 Churchill Road, Springfield, IL 62794-9276

217/782-2113

FEDERALLY ENFORCEABLE STATE OPERATING PERMIT

PERMITTEE

Granite City Division
of National Steel Corporation
Attn: Fred Steinkuehler
20th & State Street
Granite City, IL 62040

Application No.: 94120017 I.D. No.: 119813AAI
Date Received: December 12, 1994
Subject: Sulfur Dioxide Emission Limits
Date Issued: March 7, 1995
Expiration Date: February 22, 2000
Location: Granite City Division, Granite City

Permit is hereby granted to the above-designated Permittee to OPERATE emission source(s) and/or air pollution control equipment consisting of sulfur dioxide emission units as described in the above-referenced application and as enumerated in the existing permits listed in Table 1. This permit is subject to standard conditions attached hereto and the following special conditions:

1. This federally enforceable state operating permit is issued to limit sulfur dioxide emissions to levels which ensure that compliance with the national ambient air quality standard for sulfur dioxide is maintained in the surrounding area.

LIMITATIONS ON EMISSIONS AND OPERATIONS

2. Emissions of sulfur dioxide (SO2) from each unit operating group as a whole shall not exceed the following limits:

Unit Operating Group	Sulfur Dioxide Emissions* (lbs/3-hours)	(lbs/day)	(tons/yr)
Slab Reheat Furnaces (1-3)	2,299	9,754	987
Slab Reheat Furnace 4		11,873	1,204
Blast Furnace Stoves (A and B)		19,774	3,609
Boilerhouse Boilers(1-10)		20,285	3,702
Blast Furnace Boilers (11 and 12)		20,584	3,756
Ladle Drying Preheaters	555	2,786	509
Blast Furnace Casthouse Baghouse		3,430	626
Iron Spout Baghouse		170	31

*Refer to special note of the Compliance Determinations section of this permit.

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3. Fuel oil shall not be fired in the Blast Furnace Stoves and Ladle Drying Preheaters.

4a. Slab Reheat Furnaces 1-4 shall use fuel oil only from tank 5.

b. Boilerhouse Boilers 1-10 shall use fuel oil only from tank 102.

c. Blast Furnace Boilers 11 and 12 shall use fuel oil only from tank 101.

5. The Agency shall be allowed to sample all fuels at the above location.

6a. The #6 Galvanizing Line Furnace and the #6 Galvanizing Pot shall use natural gas only.

b. The #7A Galvanizing Line Furnace shall use natural gas only.

COKE OVEN GAS FLOW METERS AND HYDROGEN SULFIDE MONITOR OPERATION

7. Within 270 days of the date of issuance of this permit the Permittee shall install, test, operate, and maintain a system for monitoring the hydrogen sulfide (H2S) content of the coke oven gas (COG) and a system for measuring the COG usage for each unit operating group so as to use these two parameters in compliance calculations. These systems shall result in the acquisition of validated data which are representative of each unit operating groups emissions.

8a. A flow meter shall be maintained on the main Blast Furnace and Steelworks COG feed lines and each individual emission unit or unit operating group and shall be used to measure the COG usage rate. Flow meters shall be used to measure the COG usage on each individual emission unit or unit operating group. The total COG usage for each unit operating group as a whole shall be the sum of the individual usage for the emission units of that group as measured by the individual meters or that measured by a single flow meter measuring the COG usage for the unit operating group as a whole.

b. The COG flow meter system shall meet the applicable requirements of Performance Specification 6 of 40 CFR 60, Appendix B, i.e., flow rate measurement specifications.

c. The COG flow meter system shall be capable of recording the COG usage in standard cubic feet on a hourly basis and daily basis.

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d. The COG flow meter system shall be operated, and data collected, reduced and maintained, in accordance with the applicable requirements of 40 CFR 60.13 and 35 Ill. Adm. Code Part 201 Subpart L.

ei. Sufficient information on COG usage shall be obtained from the COG flow meter system to allow the determination of hourly and/or daily COG usage for each unit operating group, as needed for the emission rate calculations of this permit.

ii. If a single flow meter on an unit operating group fails, then the COG usage for that group may be calculated using the difference between overall total COG usage and the total COG usage at the remaining properly operating COG flow meters, or the difference in COG usage from the main COG feed line of the affected unit operating group and the COG usage at the remaining properly operating flow meters associated with that main feed line;

iii. In the event that several flow meters are down such that the above COG usage calculation is not possible, the COG usage for the affected unit operating group(s) shall be determined by a method approved by the Agency (e.g., use of temporary backup measurement system). In no case shall COG usage not be determined by a method described in this permit, or an approved alternative method, so as to result in insufficient data being obtained to determine the COG usage for any unit operating group as needed to evaluate compliance using the emission rate calculations of this permit.

9a. The Permittee shall install, operate, and maintain a continuous monitoring system to measure and record the H2S content in the COG of the main COG feed line.

b. The H2S concentration shall be measured on a wet gas basis.

c. The H2S monitoring system shall meet the applicable requirements of Performance Specification 7 of 40 CFR 60, Appendix B.

d. The H2S monitoring system shall be equipped with a strip chart recorder or disk storage and shall be capable of recording the H2S content in grains per standard cubic feet on a hourly average basis and daily average basis.

e. The H2S monitoring system shall be operated, and data collected, reduced and maintained, in accordance with the applicable requirements of 40 CFR 60.13 and 35 Ill. Adm. Code Part 201 Subpart L.

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f. The H2S monitoring system shall obtain hourly average H2S content data for at least 75% of the daily operating hours in which COG is produced (e.g., at 24 hours/day COG production, at least 18 hourly averages of H2S content must be obtained). In the event that this minimum data requirement cannot be met by the H2S monitoring system, the H2S content data shall be supplemented or obtained by one of the following alternative methods:

i. hourly manual sampling of H2S content using a modified Monier-Williams Method;

ii. H2S determined by type of coal used during that period and previous recorded H2S content when using this coal type. This method shall only be used for a maximum of 15 days per calendar year.

10 In the event of malfunction or breakdown of a COG flow meter or the H2S monitor, the Permittee shall repair and recalibrate the meter or monitor as soon as practicable but no later than 10 days after the malfunction or breakdown is detected, unless prior Agency approval is obtained by submitting adequate justification to the Agency detailing the reasons for delay. Records of repair and recalibration must be maintained in accordance with the recordkeeping requirements of this permit. This condition does not relieve the Permittee of the minimum data obtaining requirements of this permit.

COMPLIANCE DETERMINATIONS

11a. Compliance with the lbs/3-hours limits shall be demonstrated using the following emission rate calculations for eight discrete 3-hour periods per day, with the first period beginning at midnight.

b. Compliance with the daily emission limits of this permit shall be demonstrated using the following emission rate calculation equations based on a daily block basis (i.e., midnight to midnight):

12. The compliance calculations shall be the primary compliance method for determining compliance with the emission limits in this permit, except for the blast furnace casthouse baghouse and iron spout baghouse, for which stack testing shall be the primary means of determining compliance.

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13a. Total SO2 emissions from an unit operating group for determination of compliance with the SO2 limits of this permit shall be the sum of the emissions resulting from the use of COG and fuel oil at the unit operating group, i.e.:

lbs SO2 per unit operating group = SO2 emissions from fuel oil usage + SO2 emissions from COG usage

Special Note: The SO2 emissions which would result from the use of blast furnace gas and natural gas in the unit operating groups has been accounted for in the SO2 limits of this permit. This was accomplished by lowering the permitted SO2 from the SO2 levels used for air quality modeling by an amount equal to the SO2 which would have been emitted should the unit operating groups use blast furnace gas or natural gas continuously. The SO2 emissions from blast furnace gas and natural gas were calculated using standard emission factors as found in AIRS Facility Subsystem, Source Classification Codes and Emission Factor Listing for Criteria Air Pollutants, EPA Document Number EPA 450/4-90-003, and Compilation of Air Pollution Emission Factors, Vol. 1, Stationary Point and Other Sources, AP-42.

b. The SO2 emissions attributable to <u>fuel oil usage</u> shall be calculated using the recorded parameters required by this permit and the following equation:

lbs SO2/period = gallons of oil burned per period X sulfur content in weight percent of the fuel oil used X density of the fuel oil used in pounds per gallon X 2.

Note that emissions attributable to fuel oil used in each tank must be calculated individually using the most recent recorded parameters of the oil in that tank).

c. The SO2 emissions attributable to <u>COG usage</u> shall be calculated using the recorded parameters required by this permit and the following equation:

lbs SO2/period = thousand standard cubic feet of COG burned per period X average H2S content of the COG in grains per standard cubic foot for the period X 0.269.

14. Stack test measurement shall be the primary method of determining compliance of the Blast Furnace Casthouse and Iron Spout Baghouse with the lbs/day limits in this permit. The secondary means of determining compliance shall be the following emission calculation equations:

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a. The SO2 attributable to the Blast Furnace Casthouse Baghouse shall be calculated using an emission factor of 0.173 lbs SO2 per ton of hot metal cast.

b. The SO2 attributable to the Iron Spout Baghouse shall be calculated using an emission factor of 0.0063 lbs SO2 per ton of hot metal cast.

15. Compliance with the tons/yr limits of this permit shall be determined using a rolling total of 12 consecutive calendar months of data.

16ai. Usage of fuel oil for a specific time period shall be determined by monitoring the difference in oil height in a tank before and after oil use, and then converting this difference in height to gallons of oil used for that period.

ii. When fuel oil is used at both unit operating groups of Slab Reheat Furnaces 1-3 and Slab Reheat Furnace 4 during the same period such that the oil usage at each individual unit operating group is not directly measurable using the above specified difference in oil height method, the oil usage at the individual unit operating groups during such period shall be calculated using a ratio of the btu's of each unit operating group during that period times the oil usage.

bi. The sulfur content and density as determined by the ASTM methods specified in the testing requirements of this permit shall be used in emission calculations until any additional oil is added to a tank upon which the sulfur content and density of that tank as calculated in the following item (ii) shall be used.

ii. The sulfur content and density of the fuel oil shall be determined after each instance that oil is added to a tank by taking a weighted average of the sulfur content and density of the oil in that tank and the oil being added, provided that the sulfur content and density of the fuel oil being added must be determined by the ASTM methods indicated above. Alternatively, the Permittee may use the ASTM methods indicated above in lieu of using the weighted average determination method.

iii. The most recent determined values for the fuel oil weight percent sulfur content and density shall be used in compliance calculations.

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17. Usage of COG shall be determined by the COG flow meters.

18a. For use in the lbs/3-hours compliance calculations, the average H2S content of COG shall be calculated using an arithmetic average of all available H2S data during the 3-hour period that COG was burned. In the event that the H2S monitoring system is unable to obtain a single reading for the 3-hour period, the H2S content for that 3-hour period shall be obtained by one of the previously specified alternative methods of this permit (i.e., manual sampling of H2S content or determined by type of coal used during that period and previous recorded H2S content when using this coal type).

b. For use in the lbs/day compliance calculations, the daily average H2S content of COG shall be calculated using an arithmetic average of all available hourly average H2S content data for that day, and at least data from 75% of the daily operating hours.

TESTING

19a. Each COG flow meter used in compliance calculations for this permit shall be performance tested within 270 days of the issuance date of this permit, and at least every 12 months thereafter, in accordance with the procedures of 40 CFR 60, Appendix B, Performance Specification 6.

b. The results of these tests shall be sent to the Division of Air Pollution Control Permit Section and Regional Office within 14 days after compilation of results and maintained in accordance with the recordkeeping specified in this permit.

20a. The H2S monitor shall be initially, and at least every 12 months thereafter, performance tested in accordance with 40 CFR 60, Appendix B, Performance Specification 7 as follows:

b. The H2S content in grains per standard cubic foot of COG shall be determined using 40 CFR 60, Appendix A, Method 11 as adapted to measure higher ranges of H2S.

c. The following revisions shall be made to Method 11 to allow the measuring of higher ranges of H2S:

i. Diluent air shall mean air containing less than 0.5 ppm total sulfur compounds and less than 10 ppm each of moisture and hydrocarbons.

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ii. 7.0 Procedure - Located after the sampling valve, there will be a gas mixing box with a metered supply of (heated) diluent air. This metered supply of diluent air will be introduced prior to sampling and adjusted so that the final dilution of sample will be 1:20 (i.e., 0.05 liters/min of sample to 0.95 liters/min of dilution air).

iii. 9.4 - Vm = Volume of gas sample through the gas meter (meter conditions), liters/20.
VmCSTD = (corrected) volume at standard conditions of gas sampled through the dry gas meter. (Standard Liters).

d. The results of these tests shall be sent to the Division of Air Pollution Control Permit Section and Regional Office within 14 days after compilation of results and maintained in accordance with the recordkeeping specified in this permit.

21a. Within 270 days of the issuance date of this permit, and at least once every 12 months thereafter, the weight percent sulfur content and density of the fuel oil in tanks 101, 102 and 5 shall be determined by testing a representative sample of the oil in each tank.

b. Prior to taking the oil samples to be tested, the contents of tanks 101, 102 and 5 shall be mixed by utilizing the recirculation systems to ensure that the contents of the tanks are reasonably uniform, and hence representative of the entire contents of the tanks.

c. The Permittee shall use the American Society for Testing and Materials (ASTM) method D129-64 for sulfur content in weight percent and ASTM method D12-98 for density in pounds per gallon(lbs/gal).

d. The results of these tests shall be maintained at a readily accessible location at the source for a period of three years and shall be available to representatives of the Agency and USEPA for inspection and copying during daily working and/or operating hours.

22a. Emissions of sulfur dioxide from the blast furnace casthouse baghouse and/or iron spout baghouse shall be measured within 90 days of the receipt of a written request by the Agency. The Agency will provide additional time for testing upon request from the Permittee which shows that it is not feasible to perform representative testing within 90 days. These tests shall be designed to allow evaluation of compliance with the emission limits of this permit.

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b. These tests shall be performed by an independent testing service under conditions which are representative of maximum emissions.

c. The following methods shall be used for the testing:

Location of sample points	USEPA Method 1
Gas flow and velocity	USEPA Method 2
Sulfur Dioxide	USEPA Method 6B

d. The Agency shall be notified before these tests to enable the Agency to observe these tests. Notification for the expected date of testing shall be submitted a minimum of thirty (30) days prior to the expected date. Notification of the actual and expected time of testing shall be submitted a minimum of five (5) working days prior to the actual date of the test. The Agency may at its discretion accept notifications with shorter advance notice provided that the Agency will not accept such notifications if it interferes with the Agency's ability to observe testing.

e. The Final Report of these tests shall include as a minimum:

I. A tabular summary of results which includes:
- identity of the emission unit and/or units tested;
- tons of hot metal cast per day;
- sulfur dioxide emission rate in lbs/day;
- compliance demonstrated - Yes/No.

ii. Description of test methods and procedures used, including description of sampling train, analysis equipment, and test schedule.

iii. Detailed description of test conditions, including, pertinent process information (e.g. fuel or raw material consumption).

iv. Data and calculations, including copies of all raw data sheets and records of laboratory analyses, sample calculations, and data on equipment calibration.

f. Copies of the Final Report for these tests shall be submitted to the Agency within 14 days after the test results are compiled and finalized.

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g. Submittals of information shall be made as follows:

i. Notice of Test - one copy to Source Emission Test Specialist, one copy to Regional Office, and one copy to Permit Section.

ii. Final Report - one copy to Source Emission Test Specialist, one copy to Regional Office, and one copy to Permit Section.

Pertinent Addresses are:

Illinois Environmental Protection Agency
Division of Air Pollution Control
Attn: Source Emission Test Specialist
Intercontinental Center
1701 1st Avenue
Maywood, Illinois 60153

Illinois Environmental Protection Agency
Division of Air Pollution Control
Regional Office
2009 Mall Street
Collinsville, Illinois 62234

Illinois Environmental Protection Agency
Division of Air Pollution Control
Attn: Permit Section
P.O. Box 19276
Springfield, Illinois 62794-9276

RECORDKEEPING

23. Records shall be maintained of the following:

a. The hourly average, 3-hour average and daily average H2S content of the COG in grains per standard cubic foot.

b. The H2S monitor strip chart or disk storage.

c. Thousand standard cubic feet of COG used per 3-hours for slab reheat furnaces 1-3 and ladle drying preheaters and per day for each unit operating group.

d. The calibration, maintenance and repair of the H2S monitor and each COG flow meter used in compliance calculations.

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e. The weight percent sulfur content of the fuel oil in tanks 101, 102 and 5 as determined by the testing requirement of this permit and as determined after each instance that oil is added to a tank.

f. The density (lbs/gal) of the fuel oil in tanks 101, 102 and 5 as determined by the testing requirement of this permit and after each instance that oil is added to a tank.

g. Gallons of fuel oil used from tank 5 per 3-hours for slab reheat furnaces 1-3 and per day from tanks 101, 102 and 5.

h. Tons of hot metal cast per day and annually at the Blast Furnace Casthouse.

i. SO2 emissions of each unit operating group in terms of the associated emission limits of this permit (i.e., lbs/3-hrs and lbs/day) accompanied by the data from which they were determined.

j. SO2 emissions of each unit operating group in tons/month.

k. SO2 emissions of each unit operating group in tons/year determined by using a rolling total of the previous 12 consecutive months of data.

24a. The records required by this permit shall be maintained at a readily accessible location at the source for a period of three years and shall be available to representatives of the Agency and USEPA for inspection and copying during daily working and/or operating hours.

b. Written records shall be maintained in addition to any electronic records, unless parameters are directly recorded and stored in an electronic data storage system.

REPORTING

25a. Any apparent violation of the requirements (e.g., emission limits) of this permit as determined by recordkeeping or testing shall be reported to the Agency in writing within 30 days of the apparent violation. The report shall include the following:

i. The starting date and time of the apparent violation.

ii. The duration of the apparent violation.

iii. Identity of the emission units involved.

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iv. A description of the apparent violation, including the operating parameters of the emission unit(s) involved.

v. The emission levels in lbs/day that occurred.

vi. A statement identifying the probable cause(s) of the apparent violation.

vii. Corrective actions taken at the time of the apparent violation, actions taken to lessen emissions, and actions taken to prevent future occurrences.

b. The Permittee shall submit quarterly reports (every 3 calendar months) to the Agency. This report is due 30 days after the end of the reporting period and may be submitted on computer disk. This report shall contain the following information for the days during the quarter:

i. A summary showing the emissions of SO2 for each unit operating group for each day and the 12 month rolling average in tons/year.

ii. A statement identifying any apparent violations which occurred during the quarter covered by the report or, if there have been no apparent violations, a statement to that effect.

iii. A summary of any COG flow meter and H2S monitor downtime.

iv. Identification of any days for which data for at least 75% of the operating hours of the unit operating group was not obtained by an approved method; justification for not obtaining the data; and description of corrective action taken.

c. These reports shall be sent to the Agency's Compliance Monitoring Unit and Regional Office.

Pertinent addresses:

Illinois Environmental Protection Agency
Division of Air Pollution Control
Regional Office
2009 Mall Street
Collinsville, Illinois 62234

Illinois Environmental Protection Agency
Division of Air Pollution Control
Compliance and Systems Management Section
P.O. Box 19276
Springfield, Illinois 62794-9276

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Please note that the conditions of this permit supplement the conditions of existing permits listed in Table 1. These conditions are necessary to assure that the emission units, both alone and in combination with other equipment operated by the Permittee, do not cause or contribute to a violation of the SO2 air quality standard. To the extent that the above conditions are more stringent than conditions of the existing permits, the conditions of the existing permits are superseded.

If you have any questions on this, please call Jim Ross at 217/782-2113.

COPY

Original Signed by
Donald E. Sutton, P.E.

Donald E. Sutton, P.E.
Manager, Permit Section
Division of Air Pollution Control

DES:RR.GSFESOP2.DOC

cc Region 3

State of Illinois
ENVIRONMENTAL PROTECTION AGENCY

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Application No.

TABLE 1

72080034	Blast Furnace "A" Stoves and Iron Spout Baghouse
72080036	Blast Furnace "B" Stoves and Casthouse
72080038	Slab Reheat Furnaces 1-4
72080040	#6 Galvanizing Line Furnace and #6 Galvanizing Line Pot
72080043	Ladle Drying Preheaters
73031119	Boilerhouse Boilers 1-10
73031492	Blast Furnace Boiler 11
73100166	Blast Furnace Boiler 12

STATE OF ILLINOIS
ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF AIR POLLUTION CONTROL
2200 CHURCHILL ROAD
SPRINGFIELD, ILLINOIS 62706

R011916

STANDARD CONDITIONS FOR OPERATING PERMITS

July 1, 1985

The Illinois Environmental Protection Act (Illinois Revised Statutes, Chapter 111-1/2, Section 1039) grants the Environmental Protection Agency authority to impose conditions on permits which it issues.

The following conditions are applicable unless superseded by special permit condition(s).

1. The issuance of this permit does not release the permittee from compliance with state and federal regulations which are part of the Illinois State Implementation Plan, as well as with other applicable statutes and regulations of the United States or the State of Illinois or with applicable local laws, ordinances and regulations.

2. The Agency has issued this permit based upon the information submitted by the permittee in the permit application. Any misinformation, false statement or mispresentation in the application shall be grounds for revocation under 35 Ill. Adm. Code 201.207.

3. a. The permittee shall not authorize, cause, direct or allow any modification, as defined in 35 Ill. Adm. Code 201.102, of equipment, operations or practices which are reflected in the permit application as submitted unless a new application or request for revision of the existing permit is filed with the Agency and unless a new permit or revision of the existing permit(s) is issued for such modification.

   b. This permit only covers emission sources and control equipment while physically present at the indicated plant location(s). Unless the permit specifically provides for equipment relocation, this permit is void for an item of equipment on the day it is removed from the permitted location(s) or if all equipment is removed, notwithstanding the expiration date specified on the permit.

4. The permittee shall allow any duly authorized agent of the Agency, upon the presentation of credentials, at reasonable times:

   a. to enter the permittee's property where actual or potential effluent, emission or noise sources are located or where any activity is to be conducted pursuant to this permit,

   b. to have access to and to copy any records required to be kept under the terms and conditions of this permit,

   c. to inspect, including during any hours of operation of equipment constructed or operated under this permit, such equipment and any equipment required to be kept, used, operated, calibrated and maintained under this permit,

   d. to obtain and remove samples of any discharge or emission of pollutants, and

   e. to enter and utilize any photographic, recording, testing, monitoring or other equipment for the purpose of preserving, testing, monitoring or recording any activity, discharge or emission authorized by this permit.

5. The issuance of this permit:

   a. shall not be considered as in any manner affecting the title of the premises upon which the permitted facilities are located,

   b. does not release the permittee from any liability for damage to person or property caused by or resulting from the construction, maintenance, or operation of the facilities,

c. does not take into consideration or attest to the structural stability of any unit or part of the project, and

d. in no manner implies or suggests that the Agency (or its officers, agents or employees) assumes any liability, directly or indirectly, for any loss due to damage, installation, maintenance, or operation of the proposed equipment or facility.

6. The facilities covered by this permit shall be operated in such a manner that the disposal of air contaminants collected by the equipment shall not cause a violation of the Environmental Protection Act or regulations promulgated thereunder.

7. The permittee shall maintain all equipment covered under this permit in such a manner that the performance of such equipment shall not cause a violation of the Environmental Protection Act or regulations promulgated thereunder.

8. The permittee shall maintain a maintenance record on the premises for each item of air pollution control equipment. This record shall be made available to any agent of the Environmental Protection Agency at any time during normal working hours and/or operating hours. As a minimum, this record shall show the dates of performance and nature of preventative maintenance activities.

9. No person shall cause or allow continued operation during malfunction, breakdown or startup of any emission source or related air pollution control equipment if such operation would cause a violation of an applicable emission standard or permit limitation. Should a malfunction, breakdown or startup occur which results in emissions in excess of any applicable standard or permit limitation, the permittee shall:

   a. immediately report the incident to the Agency's Regional Field Operations Section Office by telephone, telegraph, or other method as constitutes the fastest available alternative, and shall comply with all reasonable directives of the Agency with respect to the incident;

   b. maintain the following records for a period of no less than two (2) years:

      i. date and duration of malfunction, breakdown or startup,

      ii. full and detailed explanation of the cause,

      iii. contaminants emitted and an estimate of quantity of emissions,

      iv. measures taken to minimize the amount of emissions during the malfunction, breakdown or startup, and

      v. measures taken to reduce future occurrences and frequency of incidents.

10. If the permit application contains a compliance program and project completion schedule, the permittee shall submit a project completion status report within thirty (30) days of any date specified in the compliance program and project completion schedule or at six month intervals, whichever is more frequent.

11. The Permittee shall submit an Annual Emission Report as required by 35 Ill. Adm. Code. 201.302 and 35 Ill. Adm. code Part 254.

Romaine, Chris

From: Brubaker, Sarah
Sent: Tuesday, May 7, 2024 4:00 PM
To: Romaine, Chris
Subject: RE: US Steel Denial

Thanks for letting me know! Talk to you tomorrow.

Sarah
Sarah Brubaker (she/her)
Community Relations Coordinator
Office of Community Relations
Sarah.Brubaker@Illinois.gov
(217)786-0790

From: Romaine, Chris <Chris.Romaine@Illinois.gov>
Sent: Tuesday, May 7, 2024 3:59 PM
To: Brubaker, Sarah <Sarah.Brubaker@Illinois.gov>
Subject: US Steel Denial

FYI

I will not be denying the application today.

Better for me not to rush to get it out of here today. Tomorrow will do.

State of Illinois - CONFIDENTIALITY NOTICE: The information contained in this communication is confidential, may be attorney-client privileged or attorney work product, may constitute inside information or internal deliberative staff communication, and is intended only for the use of the addressee. Unauthorized use, disclosure or copying of this communication or any part thereof is strictly prohibited and may be unlawful. If you have received this communication in error, please notify the sender immediately by return e-mail and destroy this communication and all copies thereof, including all attachments. Receipt by an unintended recipient does not waive attorney-client privilege, attorney work product privilege, or any other exemption from disclosure.

Romaine, Chris

From: Romaine, Chris
Sent: Wednesday, May 8, 2024 11:13 AM
To: Brubaker, Sarah
Subject: US Steel Final Denial Letter 95010001 4-30-24l.docx
Attachments: US Steel Final Denial Letter 95010001 4-30-24l.docx

Done!

Here is the denial letter.

Romaine, Chris

From: Romaine, Chris
Sent: Wednesday, May 8, 2024 11:16 AM
To: Brubaker, Sarah
Subject: US Steel 95010001 final response complete 05-08-2024.docx
Attachments: US Steel 95010001 final response complete 05-08-2024.docx

And here is the Responsiveness Summary .

Romaine, Chris

From: Brubaker, Sarah
Sent: Wednesday, May 8, 2024 12:18 PM
To: Romaine, Chris
Subject: US Steel 95010001
Attachments: US Steel Responsiveness Summary Letter.docx

Both documents have been posted to the website. Attached is the notification letter that will be sent to the commenters. The distribution list is on the last page for the file. Let me know if you need anything else.

Thanks!

Sarah Brubaker (she/her)
Community Relations Coordinator
Office of Community Relations
Sarah.Brubaker@Illinois.gov
(217)786-0790

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217/785-1705

TITLE V - CLEAN AIR ACT PERMIT PROGRAM (CAAPP) PERMIT
REVISED

PERMITTEE:

U. S. Steel Corporation
Granite City Works
Attn: Bryan Kresak
20th and State Streets
Granite City, Illinois 62040

I.D. No.: 119813AAI
Application No.: 96030056

Date Originally Received: March 6, 1996
Date Originally Issued: September 3, 2009
Date Revised Permit Issued: March 4, 2013
Expiration Date[1]: September 3, 2014

Operation of: Integrated Steel Mill
Source Location: 20th and State Streets, Granite City
Responsible Official: Richard E. Veitch, General Manager

This permit is hereby granted to the above-designated Permittee to OPERATE an Integrated Steel Mill Plant, pursuant to the above referenced permit application. This permit is subject to the conditions contained herein.

This permit was revised on March 4, 2013, in accordance with Sections 39.5(9)(e) through (g) of the Environmental Protection Act, pursuant to an order from Lisa P. Jackson, Administrator of the USEPA, *In the Matter of United States Steel Corporation - Granite City Works*, Petition Number V-2011-2 (December 3, 2012), which order was received by the Illinois EPA on December 4, 2012.

If you have any questions concerning this permit, please contact Anatoly Belogorsky or Michael Reed at 217/785-1705.

Edwin C. Bakowski, P.E.
Manager, Permit Section
Division of Air Pollution Control

ECB:MR:psj

cc: Illinois EPA, FOS, Region 3
CES
Lotus Notes

[1] Except as provided in Conditions 1.5 and 8.7 of this permit.

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1.0 SOURCE IDENTIFICATION

1.1 Source

U. S. Steel Corporation
Granite City Works
20th and State Streets
Granite City, Illinois 62040
618/451-3456

I.D. No.: 119813AAI
County: Madison
Standard Industrial Classification: 3312, Integrated Steel Mill

Responsible Official: Richard E. Veitch, General Manager

Delegated Authorities:
Michelle Fields, Division Manager - Coke and Iron Making;
Michael Terry, Division Manager - Steelmaking

1.2 Owner/Parent Company

United States Steel Corporation
600 Grant Street
Pittsburgh, Pennsylvania 15219

1.3 Operator

U. S. Steel Corporation
Granite City Works
20th and State Streets
Granite City, Illinois 62040

Contact Person:
Bryan Kresak, Manager Environmental Control
618/451-3456

1.4 Source Description

Integrated steel manufacturing employing raw material processing/preparation, coke production, iron production, steel production, and steel finishing.

1.5 Title I Conditions

As generally identified below, this CAAPP permit contains certain conditions for emission units at this source that address the applicability of permitting programs for the construction and modification of sources, which programs were established pursuant to Title I of the Clean Air Act (CAA) and regulations thereunder. These programs include 40 CFR 52.21, Prevention of Significant Deterioration (PSD) and 35 IAC Part 203, Major Stationary Sources Construction and Modification (MSSCAM), and are implemented by the Illinois EPA pursuant to Sections 9, 9.1, 39(a) and 39.5(7)(a) of the Illinois Environmental Protection Act (Act). These conditions continue in effect,

notwithstanding the expiration date specified on the first page of this permit, as their authority derives from Titles I and V of the CAA, as well as Titles II and X of the Act. (See also Condition 8.7.)

a. This permit contains "Title I Conditions" that reflect Title I requirements established in permits previously issued for this source, which conditions are specifically designated as "T1".

b. This permit contains Title I conditions that are newly established in this CAAPP permit, which conditions are specifically designated as "T1N".

2.0 LIST OF ABBREVIATIONS AND ACRONYMS COMMONLY USED

ACMA	Alternative Compliance Market Account
Act	Illinois Environmental Protection Act [415 ILCS 5/1 et seq.]
AP-42	Compilation of Air Pollutant Emission Factors, Volume 1, Stationary Point and Other Sources (and Supplements A through F), USEPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711
ATU	Allotment Trading Unit
BACT	Best Available Control Technology
BAT	Best Available Technology
BFG	Blast Furnace Gas
BOF	Basic Oxygen Furnace
BOPF	Basic Oxygen Process Furnace
BTX	Benzene, toluene and xylene
CAA	Clean Air Act [42 U.S.C. Section 7401 et seq.]
CAAPP	Clean Air Act Permit Program
CAM	Compliance Assurance Monitoring
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
COG	Coke Oven Gas
COG-DS	Coke Oven Gas Desulfurization System
COMS	Continuous Opacity Monitoring System
CPMS	Continuous Parameters Monitoring System
dscf	Dry standard cubic feet
ERMS	Emissions Reduction Market System
ESP	Electro Static Precipitator
°F	Fahrenheit
FESOP	Federally Enforceable State Operating Permit
GHG	Greenhouse Gases
gr	grains
HAP	Hazardous Air Pollutant
HCL	Hydrogen Chloride
H_2S	Hydrogen Sulfate
IAC	Illinois Administrative Code
I.D. No.	Identification Number of Source, assigned by Illinois EPA
ILCS	Illinois Compiled Statutes
Illinois EPA	Illinois Environmental Protection Agency
LAER	Lowest Achievable Emission Rate
LMF	Ladle Metallurgy Furnace
MACT	Maximum Achievable Control Technology
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
PM	Particulate Matter
PM_{10}	Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 microns as measured by applicable test or monitoring methods

$PM_{2.5}$	Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 microns as measured by applicable test or monitoring methods
ppm	Parts per million
PSD	Prevention of Significant Deterioration
RMP	Risk Management Plan
scf	Standard cubic feet
SO_2	Sulfur Dioxide
SSM	Startup, Shutdown and Malfunction
T1	Title I - identifies Title I conditions that have been carried over from an existing permit
T1N	Title I New - identifies Title I conditions that are being established in this permit
T1R	Title I Revised - identifies Title I conditions that have been carried over from an existing permit and subsequently revised in this permit
USEPA	United States Environmental Protection Agency
VHAP	Volatile Hazardous Air Pollutant
VOM	Volatile Organic Material

3.0 CONDITIONS FOR INSIGNIFICANT ACTIVITIES

3.1 Identification of Insignificant Activities

The following activities at the source constitute insignificant activities as specified in 35 IAC 201.210:

3.1.1 Activities determined by the Illinois EPA to be insignificant activities, pursuant to 35 IAC 201.210(a)(1) and 201.211, as follows:

a. Material Handling and Processing Operations

N/A

b. Coke Production

N/A

c. Coke Oven Gas By-Products Recovery Plant

Ammonium Sulfate Handling

d. Blast Furnaces

N/A

e. Basic Oxygen Furnaces

N/A

f. Continuous Casting

Tanks #543, #544, #545, #555

g. Finishing Operations

Scale Pits
#6 Zinc Pot (Backup)
#7 and #8 Zinc Pots
Storage Tanks ##306-310, #403, #427, #800, #815

h. Wastewater Treatment

N/A

i. Boiler Houses

N/A

3.1.2 Activities that are insignificant activities based upon maximum emissions, pursuant to 35 IAC 201.210(a)(2) or (a)(3), as follows:

a. Material Handling Operations

N/A

b. Coke Production

N/A

c. Coke Oven Gas By-Products Recovery Plant

Storage Tanks #116, #117, #118, #120

d. Blast Furnaces

Torpedo Car Dekishing

e. Basic Oxygen Furnaces

Lime/Magnesium Handling and Storage Unit

f. Continuous Casting

N/A

g. Finishing Operations

72" Line and Cold Mill

h. Wastewater Treatment

N/A

i. Boiler Houses

N/A

3.1.3 Activities that are insignificant activities based upon their type or character, pursuant to 35 IAC 201.210(a)(4) through (18), as follows:

a. Material Handling Operations

Direct combustion units designed and used for comfort heating purposes and fuel combustion emission units as follows: (A) Units with a rated heat input capacity of less than 2.5 mmBtu/hr that fire only natural gas, propane, or liquefied petroleum gas; (B) Units with a rated heat input capacity of less than 1.0 mmBtu/hr that fire only oil or oil in combination with only natural gas, propane, or liquefied petroleum gas; and (C) Units with a rated heat input capacity of less than 200,000 Btu/hr which never burn refuse, or treated or chemically contaminated wood [35 IAC 201.210(a)(4)].

b. Coke Production

Direct combustion units designed and used for comfort heating purposes and fuel combustion emission units as follows: (A) Units with a rated heat input capacity of less than 2.5 mmBtu/hr that fire only natural gas, propane, or liquefied petroleum gas; (B) Units with a rated heat input capacity of less than 1.0 mmBtu/hr that fire only oil or oil in combination with only natural gas, propane, or liquefied petroleum gas; and (C) Units with a rated heat input capacity of less than 200,000 Btu/hr which never burn refuse, or treated or chemically contaminated wood [35 IAC 201.210(a)(4)].

Storage tanks of virgin or re-refined distillate oil, hydrocarbon condensate from natural gas pipeline or storage systems, lubricating oil, or residual fuel oils [35 IAC 201.210(a)(11)].

Storage tanks of any size containing exclusively soaps, detergents, surfactants, glycerin, waxes, vegetable oils, greases, animal fats, sweeteners, corn syrup, aqueous salt solutions, or aqueous caustic solutions, provided an organic solvent has not been mixed with such materials [35 IAC 201.210(a)(17)].

c. Coke Oven Gas By-Products Recovery Plant

Storage tanks of organic liquids with a capacity of less than 10,000 gallons and an annual throughput of less than 100,000 gallons, provided the storage tank is not used for the storage of gasoline or any material listed as a HAP pursuant to Section 112(b) of the CAA [35 IAC 201.210(a)(10)].

Storage tanks of virgin or re-refined distillate oil, hydrocarbon condensate from natural gas pipeline or storage systems, lubricating oil, or residual fuel oils [35 IAC 201.210(a)(11)].

Storage tanks of any size containing exclusively soaps, detergents, surfactants, glycerin, waxes, vegetable oils, greases, animal fats, sweeteners, corn syrup, aqueous salt solutions, or aqueous caustic solutions, provided an organic solvent has not been mixed with such materials [35 IAC 201.210(a)(17)].

d. Blast Furnaces

Direct combustion units designed and used for comfort heating purposes and fuel combustion emission units as follows: (A) Units with a rated heat input capacity of less than 2.5 mmBtu/hr that fire only natural gas, propane, or liquefied petroleum gas; (B) Units with a rated heat input capacity of less than 1.0 mmBtu/hr that fire only oil or oil in combination with only natural gas, propane, or liquefied petroleum gas; and (C) Units with a rated heat

input capacity of less than 200,000 Btu/hr which never burn refuse, or treated or chemically contaminated wood [35 IAC 201.210(a)(4)].

Storage tanks of virgin or re-refined distillate oil, hydrocarbon condensate from natural gas pipeline or storage systems, lubricating oil, or residual fuel oils [35 IAC 201.210(a)(11)].

e. Basic Oxygen Furnaces

Direct combustion units designed and used for comfort heating purposes and fuel combustion emission units as follows: (A) Units with a rated heat input capacity of less than 2.5 mmBtu/hr that fire only natural gas, propane, or liquefied petroleum gas; (B) Units with a rated heat input capacity of less than 1.0 mmBtu/hr that fire only oil or oil in combination with only natural gas, propane, or liquefied petroleum gas; and (C) Units with a rated heat input capacity of less than 200,000 Btu/hr which never burn refuse, or treated or chemically contaminated wood [35 IAC 201.210(a)(4)].

Storage tanks of organic liquids with a capacity of less than 10,000 gallons and an annual throughput of less than 100,000 gallons, provided the storage tank is not used for the storage of gasoline or any material listed as a HAP pursuant to Section 112(b) of the CAA [35 IAC 201.210(a)(10)].

f. Continuous Casting

Direct combustion units designed and used for comfort heating purposes and fuel combustion emission units as follows: (A) Units with a rated heat input capacity of less than 2.5 mmBtu/hr that fire only natural gas, propane, or liquefied petroleum gas; (B) Units with a rated heat input capacity of less than 1.0 mmBtu/hr that fire only oil or oil in combination with only natural gas, propane, or liquefied petroleum gas; and (C) Units with a rated heat input capacity of less than 200,000 Btu/hr which never burn refuse, or treated or chemically contaminated wood [35 IAC 201.210(a)(4)].

Storage tanks of organic liquids with a capacity of less than 10,000 gallons and an annual throughput of less than 100,000 gallons, provided the storage tank is not used for the storage of gasoline or any material listed as a HAP pursuant to Section 112(b) of the CAA [35 IAC 201.210(a)(10)].

Storage tanks of virgin or re-refined distillate oil, hydrocarbon condensate from natural gas pipeline or storage systems, lubricating oil, or residual fuel oils [35 IAC 201.210(a)(11)].

Storage tanks of any size containing exclusively soaps, detergents, surfactants, glycerin, waxes, vegetable oils, greases, animal fats, sweeteners, corn syrup, aqueous salt solutions, or aqueous caustic solutions, provided an organic solvent has not been mixed with such materials [35 IAC 201.210(a)(17)].

g. Finishing Operations

Direct combustion units designed and used for comfort heating purposes and fuel combustion emission units as follows: (A) Units with a rated heat input capacity of less than 2.5 mmBtu/hr that fire only natural gas, propane, or liquefied petroleum gas; (B) Units with a rated heat input capacity of less than 1.0 mmBtu/hr that fire only oil or oil in combination with only natural gas, propane, or liquefied petroleum gas; and (C) Units with a rated heat input capacity of less than 200,000 Btu/hr which never burn refuse, or treated or chemically contaminated wood [35 IAC 201.210(a)(4)].

Storage tanks of organic liquids with a capacity of less than 10,000 gallons and an annual throughput of less than 100,000 gallons, provided the storage tank is not used for the storage of gasoline or any material listed as a HAP pursuant to Section 112(b) of the CAA [35 IAC 201.210(a)(10)].

Storage tanks of virgin or re-refined distillate oil, hydrocarbon condensate from natural gas pipeline or storage systems, lubricating oil, or residual fuel oils [35 IAC 201.210(a)(11)].

Storage tanks of any size containing exclusively soaps, detergents, surfactants, glycerin, waxes, vegetable oils, greases, animal fats, sweeteners, corn syrup, aqueous salt solutions, or aqueous caustic solutions, provided an organic solvent has not been mixed with such materials [35 IAC 201.210(a)(17)].

h. Wastewater Treatment

Storage tanks of organic liquids with a capacity of less than 10,000 gallons and an annual throughput of less than 100,000 gallons, provided the storage tank is not used for the storage of gasoline or any material listed as a HAP pursuant to Section 112(b) of the CAA [35 IAC 201.210(a)(10)].

Storage tanks of virgin or re-refined distillate oil, hydrocarbon condensate from natural gas pipeline or storage systems, lubricating oil, or residual fuel oils [35 IAC 201.210(a)(11)].

Storage tanks of any size containing exclusively soaps, detergents, surfactants, glycerin, waxes, vegetable oils, greases, animal fats, sweeteners, corn syrup, aqueous salt solutions, or aqueous caustic solutions, provided an organic solvent has not been mixed with such materials [35 IAC 201.210(a)(17)].

i. Boiler Houses

Direct combustion units designed and used for comfort heating purposes and fuel combustion emission units as follows: (A) Units with a rated heat input capacity of less than 2.5 mmBtu/hr that fire only natural gas, propane, or liquefied petroleum gas; (B) Units with a rated heat input capacity of less than 1.0 mmBtu/hr that fire only oil or oil in combination with only natural gas, propane, or liquefied petroleum gas; and (C) Units with a rated heat input capacity of less than 200,000 Btu/hr which never burn refuse, or treated or chemically contaminated wood [35 IAC 201.210(a)(4)].

Storage tanks of organic liquids with a capacity of less than 10,000 gallons and an annual throughput of less than 100,000 gallons, provided the storage tank is not used for the storage of gasoline or any material listed as a HAP pursuant to Section 112(b) of the CAA [35 IAC 201.210(a)(10)].

Storage tanks of virgin or re-refined distillate oil, hydrocarbon condensate from natural gas pipeline or storage systems, lubricating oil, or residual fuel oils [35 IAC 201.210(a)(11)].

Gas turbines and stationary reciprocating internal combustion engines of less than 112 kW (150 horsepower) power output [35 IAC 201.210(a)(15)].

Storage tanks of any size containing exclusively soaps, detergents, surfactants, glycerin, waxes, vegetable oils, greases, animal fats, sweeteners, corn syrup, aqueous salt solutions, or aqueous caustic solutions, provided an organic solvent has not been mixed with such materials [35 IAC 201.210(a)(17)].

3.1.4 Activities that are considered insignificant activities pursuant to 35 IAC 201.210(b). Note: These activities are not required to be individually listed.

3.2 Compliance with Applicable Requirements

Insignificant activities are subject to applicable requirements notwithstanding status as insignificant activities. In particular, in addition to regulations of general applicability, such as 35 IAC 212.301 and 212.123 (Condition 5.3.2), the Permittee shall comply with the following requirements, as applicable:

3.2.1 For each particulate matter process emission unit, the Permittee shall comply with the applicable particulate matter emission limit of 35 IAC 212.321 or 212.322 (see Attachment 2) and 35 IAC Part 266. For example, the particulate matter emissions from a process emission unit shall not exceed 0.55 pounds per hour if the emission unit's process weight rate is 100 pounds per hour or less, pursuant to 35 IAC 266.110.

3.2.2 For each organic material emission unit that uses organic material, e.g., a mixer or printing line, the Permittee shall comply with the applicable VOM emission limit of 35 IAC 219.301, which requires that organic material emissions not exceed 8.0 pounds per hour or, if no odor nuisance exists, do not qualify as photochemically reactive material as defined in 35 IAC 211.4690.

3.2.3 For each cold cleaning degreaser, the Permittee shall comply with the applicable equipment and operating requirements of 35 IAC 219.182.

3.2.4 For each open burning activity, the Permittee shall comply with 35 IAC Part 237, including the requirement to obtain a permit for open burning in accordance with 35 IAC 237.201, if necessary.

3.2.5 For each storage tank that has a storage capacity greater than 946 liters (250 gallons) and, if no odor nuisance exists, that stores an organic material with a vapor pressure exceeding 2.5 psia, the Permittee shall comply with the applicable requirements of 35 IAC 219.122, which requires use of a permanent submerged loading pipe, submerged fill, a vapor recovery system, or an equivalent device approved by the Illinois EPA. [Note: storage tanks used for storing gasoline and any hazardous air pollutants are not eligible for insignificant activities].

3.2.6 For sulfuric acid operations and storage, the Permittee shall comply with the following emission limits of sulfuric acid and/or sulfur trioxide from all emission sources (with the exception of fuel combustion emission sources and acid manufacturing) at a plant or premises, pursuant to 35 IAC 214.303:

a. 45.4 grams in any one hour period for sulfuric acid usage less than 1180 Mg/yr (100 percent acid basis) (0.10 lbs/hr up to 1300 T/yr); and

b. 250 grams per metric ton of acid used for sulfuric acid usage greater than or equal to 1180 Mg/yr (100 percent acid basis) (0.50 lbs/T over 1300 T/yr).

3.3 Addition of Insignificant Activities

3.3.1 The Permittee is not required to notify the Illinois EPA of additional insignificant activities present at the source of a

type that is identified in Condition 3.1, until the renewal application for this permit is submitted, pursuant to 35 IAC 201.212(a).

3.3.2 The Permittee must notify the Illinois EPA of any proposed addition of a new insignificant activity of a type addressed by 35 IAC 201.210(a) and 201.211 other than those identified in Condition 3.1, pursuant to Section 39.5(12)(b) of the Act.

3.3.3 The Permittee is not required to notify the Illinois EPA of additional insignificant activities present at the source of a type identified in 35 IAC 201.210(b).

4.0 SUMMARY OF SIGNIFICANT EMISSION UNITS AT THIS SOURCE

Department	Description	Emission Control Equipment	Section
Material Handling and Processing Operations	Coal Crusher, Coal Pulverizer, Conveyors, Screens, Storage Bins, Feed Hoppers	Baghouse, Various Dust Collectors and Enclosures	7.1
Coke Production	Coke Oven Batteries "A" and "B" Coke Quenching	Water Scrubber; Flares Tower, Baffles	7.2
Coke By-Product Recovery Plant	Various Storage Tanks and Process Vessels	Vapor Recovery System and Various Blanketing and Negative Pressure Systems	7.3
COG Desulfurization System	Amine Unit and SRU Unit	Thermal Oxidizer	
COG System	Holding Tank and COG Flare	None	
Blast Furnaces	Blast Furnaces "A" and "B" BFG Flares #1 and #2	Casthouse Baghouse; Iron Spout Baghouse	7.4
Basic Oxygen Processes	BOF #1/#2 and Auxiliary Equipment	Electrostatic Precipitator; Baghouses	7.5
Continuous Casting	Continuous Casting and Slab Formation	None	7.6
Hot Strip Mill	Slab Reheat Furnaces	None	7.7
Finishing Operations	Pickling Line, Galvanizing Lines, Coating Operations	Fume Scrubbers; Catalytic Converter	7.8
Wastewater Treatment Plant	Various tanks, filtration and Lagoons	None	7.9
Boilers	Power Boiler #1 Boilers #11 and #12 Cooling Water Tower Portable Boilers #1 - #4	Flue Gas Recirculation (planned for Boilers #11 and #12)	7.10
Internal Combustion Engine	Emergency Engine-Generator	None	7.11
Gasoline Storage and Dispensing	Four Gasoline Storage Tanks and associated Dispensing Operations	None	7.12

Department	Description	Emission Control Equipment	Section
Fugitive Dust	Landfill Vehicular Traffic on Roadways, Parking Lots and Other Open Areas Storage Piles including truck unloading, wind erosion and material transfer from storage piles, beaching areas	None	7.13

5.0 OVERALL SOURCE CONDITIONS

5.1 Applicability of Clean Air Act Permit Program (CAAPP)

5.1.1 This permit is issued based on the source requiring a CAAPP permit as a major source of NO_x, PM_{10}, SO_2, VOM, CO, GHG and HAP emissions.

5.1.2 For purposes of the CAAPP, U.S. Steel is considered a single source with Stein Steel Mill Services (I.D. 119813AAD) located at 20th Street and Edwardsville in Granite City. Stein Steel Mill Services has a separate CAAPP permit for it operations.

5.1.3 For purposes of the CAAPP, U.S. Steel is considered a single source with Granite City Slag, LLC (I.D. 119040ATF) located at 20th Street and Edwardsville in Granite City. Granite City Slag has a separate CAAPP permit for it operations.

5.1.4 For purposes of the CAAPP, U.S. Steel is considered a single source with AKJ Industries, Inc (I.D. 119040AEB) located at 20th Street and Edwardsville in Granite City. AKJ Industries has a separate CAAPP permit for it operations.

5.1.5 For purposes of the CAAPP, U.S. Steel is considered a single source with Oil Technology, Inc (I.D. 119040ATG) located onsite of Granite City Steel (Route 203) in Granite City. Oil Technology has a separate CAAPP permit for it operations.

5.1.6 For purposes of the CAAPP, U.S. Steel is considered a single source with Tube City IMS (I.D.119040ATL) located at 2500 East 23rd Street in Granite City. Tube City has a separate CAAPP permit for it operations.

5.1.7 For purposes of the CAAPP, U.S. Steel is considered a single source with Gateway Energy & Coke Co LLC (I.D. 119040ATN) located at Edwardsville Road in Granite City. Gateway Energy & Coke has elected to obtain a separate CAAPP permit for its operations.

5.2 Area Designation

5.2.1 This permit is issued based on the source being located in an area that, as of the date of permit issuance, is designated nonattainment for the National Ambient Air Quality Standards for ozone (moderate nonattainment), $PM_{2.5}$ and lead, and attainment or unclassifiable for all other criteria pollutants (PM_{10}, CO, NO_x, SO_2).

5.3 Source-Wide Applicable Provisions and Regulations

5.3.1 Specific emission units at this source are subject to particular regulations as set forth in Section 7 (Unit-Specific Conditions for Specific Emission Units) of this permit.

5.3.2 Fugitive Dust

a. This source shall be operated under the provisions of Fugitive Particulate Matter Operating Program prepared by the Permittee and submitted to the Illinois EPA for its review. Such operating program shall be designed to significantly reduce fugitive particulate matter emissions [35 IAC 212.309(a)]. The Permittee shall comply with the fugitive particulate matter operating program and any amendments to the program submitted pursuant to Condition 5.3.2(b), as required by 35 IAC 212.309. As a minimum, the operating program shall include provisions identified in 35 IAC 212.310(a) through (g) and the following:

   i. A detailed description of the best management practices utilized to achieve compliance with 35 IAC 212.304 through 212.308.

   ii. Estimated frequency of application of dust suppressants by location; and

   iii. Such other information as may be necessary to facilitate the Illinois EPA's review of the operating program.

b. Pursuant to 35 IAC 212.312, the operating program shall be amended from time to time by the Permittee so that the operating program is current. Such amendments shall be consistent with the requirements set forth by this Condition 5.3.2 and shall be submitted to the Illinois EPA within 30 days of such amendment.

c. In addition to the items described above in Condition 5.3.2(a), the Permittee shall include the following additional plans and programs as part of the Fugitive Particulate Matter Operating Program:

   i. Housekeeping program for non-roadway areas as required by Condition 7.13.5(a)(i)(B);

   ii. Road Cleaning Program as required by Condition 7.13.5(d); and

   iii. On-site fugitive dust control program as referenced in Condition 7.13.9(b).

d. The revised Fugitive Particulate Matter Operating Program, submitted by the Permittee on August 12, 2009, (identified as Revision 8 and necessitated by changes to responsible officials and description of areas treated) and containing an attached Table and Map for the iron-making and steel-making roads respectively), is incorporated herein by reference. The document constitutes the formal operating program required under 35 IAC 212.310, addressing the control of fugitive particulate matter emissions from all plant roadways, including the iron-making and steel-making

roads, storage piles, access areas near storage piles, and other subject operations located at the facility that are subject to 35 IAC 212.309.

Any future revision to the aforementioned operating program made by the Permittee during the permit term is automatically incorporated by reference provided that said revision is not expressly disapproved, in writing, by the Illinois EPA within 30 days of receipt of said revision. In the event that the Illinois EPA notifies the Permittee of a deficiency with any revision to the operating program, the Permittee shall be required to revise and resubmit the operating program within 30 days of receipt of notification to address the deficiency [415 ILCS 39.5(7)(a)].

e. Pursuant to 35 IAC 212.301, the affected emission units at the source shall not cause or allow the emission of fugitive particulate matter from any process, including any material handling or storage activity, that is visible by an observer looking generally toward the zenith at a point beyond the property line of the source.

f. Pursuant to 35 IAC 212.307, all unloading and transporting operations of materials collected by pollution control equipment shall be enclosed or shall utilize spraying, pelletizing, screw conveying or other equivalent methods.

5.3.3 PM_{10} Contingency Measure Plan

a. This stationary source meets the criteria in 35 IAC 212.700 and is required to prepare and submit a contingency measure plan reflecting the PM_{10} emission reductions as set forth in 35 IAC 212.701 and 212.703.

b. PM_{10} Contingency Measure Plan shall be implemented by the Permittee in accordance with 35 IAC 212.704 upon notification from the Illinois EPA.

c. Pursuant to 35 IAC 212.701(c), for operational changes subject to Sections 212.304, 212.305, 212.306, 212.308, 212.316(a) through (e), 212.424 or 212.464 which require either a new permit or a revision to an existing permit the Permittee shall, within 30 days after such changes, submit a request to modify this CAAPP permit in order to include a new, appropriate contingency measure plan.

d. The plan, as submitted by the Permittee on November 15, 1994 (which includes tabulations of PM_{10} fugitive emissions, maps for the steel-works and iron making respectively, and a comparative analysis of contingency requirements and existing road programs), is incorporated herein by reference. The document constitutes the formal PM_{10} Contingency Measure Plan required by 35 IAC 212.701, addressing the Levels 1 and 2 control measures for reducing annual source-wide fugitive emissions of PM_{10} from plant

roads (paved and unpaved) and materials handling operations in the event of an exceedance of the 24-hour ambient air quality standard for PM10 under 35 IAC 212.704 or 212.705.

5.3.4 Ozone Depleting Substances

The Permittee shall comply with the standards for recycling and emissions reduction of ozone depleting substances pursuant to 40 CFR Part 82, Subpart F, except as provided for motor vehicle air conditioners in Subpart B of 40 CFR Part 82:

a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR 82.156.

b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.

c. Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 CFR 82.161.

5.3.5 Standards for Asbestos Demolition and Renovation (40 CFR 61.145)

a. Prior to demolition or renovation of the affected facility or part of the affected facility, the Permittee shall fulfill notification requirements established by 40 CFR 61.145(b).

b. During demolition or renovation, the Permittee shall comply with the procedures for asbestos emission control established by 40 CFR 61.145(c).

5.3.6 Future Emission Standards

Should this stationary source become subject to a regulation under 40 CFR Parts 60, 61, 62, or 63, or 35 IAC Subtitle B after the date this permit is issued, then the owner or operator shall, in accordance with the applicable regulation(s), comply with the applicable requirements by the date(s) specified and shall certify compliance with the applicable requirements of such regulation(s) as part of the annual compliance certification, as required by Condition 9.8. This permit may also have to be revised or reopened to address such new regulations (see Condition 9.12.2).

5.3.7 Episode Action Plan

a. Pursuant to 35 IAC 244.141, the Permittee shall maintain at the source and have on file with the Illinois EPA a written Episode Action Plan (plan) for reducing the levels of emissions during yellow alerts, red alerts, and emergencies, consistent with safe operating procedures.

b. The Permittee shall immediately implement the appropriate steps described in this plan should an air pollution alert or emergency be declared, as required by 35 IAC 244.169, or as may otherwise be required under 35 IAC 244, Appendix D.

c. If an operational change occurs at the source which invalidates the plan, a revised plan shall be submitted to the Illinois EPA for review within 30 days of the change, pursuant to 35 IAC 244.143(d). Such plans shall be further revised if disapproved by the Illinois EPA.

d. The revised plan, submitted by the Permittee on October 19, 2009, (which contains a completed APC Form 100 and attached Tables I-V identifying additional actions to be implemented), is incorporated herein by reference. The document constitutes the formal Episode Action Plan required by 35 IAC 244.142, addressing the actions that will be implemented to reduce SO_2, PM_{10}, NO_2, CO and VOM emissions from various emissions units in the event of a yellow alert, red alert or emergency issued under 35 IAC 244.161-244.165.

Any future revision to the aforementioned plan made by the Permittee during the permit term is automatically incorporated by reference provided that said revision is not expressly disapproved, in writing, by the Illinois EPA within 30 days of receipt of said revision. In the event that the Illinois EPA notifies the Permittee of a deficiency with any revision to the plan, the Permittee shall be required to revise and resubmit the plan within 30 days of receipt of notification to address the deficiency [415 ILCS 39.5(7)(a)].

5.3.8 Risk Management Plan (RMP)

Should this stationary source, as defined in 40 CFR 68.3, become subject to the federal regulations for Chemical Accident Prevention in 40 CFR Part 68, then the owner or operator shall submit the items below. This condition is imposed in this permit pursuant to 40 CFR 68.215(a)(2)(i) and (ii).

a. A compliance schedule for meeting the requirements of 40 CFR Part 68 by the date provided in 40 CFR 68.10(a); or

b. A certification statement that the source is in compliance with all requirements of 40 CFR Part 68, including the registration and submission of the RMP, as part of the annual compliance certification required by Condition 9.8.

5.3.9 Energy Assessment (40 CFR 63, Subpart DDDDD)

Pursuant to 40 CFR 63.7500(a)(1) and Item 3 of Table 3 of 40 CFR 63 Subpart DDDDD, the Permittee must have a one-time energy assessment performed on the major source facility (i.e., the facility) by a qualified energy assessor. This energy

assessment shall be completed no later than the applicable compliance date of this NESHAP for existing sources and meet requirements in Table 3, including preparation of a comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments. This energy assessment shall be conducted consistent with the definitions for "energy assessment", "energy management practices" and "energy use system" in 40 CFR 63.7575

5.4 Source-Wide Non-Applicability of Regulations of Concern

a. Except where noted, 35 IAC 212.321 and 212.322 shall not apply to the steel manufacturing processes subject to 35 IAC 212.442 through 212.452 [35 IAC 212.441].

b. Except where noted, emission limitations of 35 IAC 212.324 are not applicable to any emission unit subject to a specific emissions standard or limitation contained in 35 IAC Subpart R, Primary and Fabricated Metal Products and Machinery Manufacture pursuant to 35 IAC 212.324(a)(3)(C).

c. This source (as a source of coke manufacturing, by-products recovery plant, iron and steel production) is excluded from the control requirements of 35 IAC Part 219 Subpart TT pursuant to 35 IAC 219.980(e).

d. This source does not receive any off-site waste as defined in 40 CFR 63.680(b) and, therefore is not subject to 40 CFR Part 63 Subpart DD "Off-site Waste and Recovery Operations".

e. The source is not required to address 40 CFR Part 64, Compliance Assurance Monitoring (CAM) for Major Stationary Sources at the time of issuance of this permit, because the initial CAAPP application was submitted prior to April 1998 [40 CFR 64.5(a)(1)].

5.5 Source-Wide Control Requirements and Work Practices

The Permittee (U.S. Steel), in conjunction with Gateway Energy and Coke Company shall maintain 267.77 tons of PM_{10} emission offsets generated by the following activities/projects (see also Sections 7.3 and 7.13):

Activity/Project	(Tons/Year)
Coke Oven Gas (COG) Desulfurization Project	31.74
Road Cleaning Program	236.03
Total:	267.77

a. These emission reductions have been relied upon by the Illinois EPA to issue Construction Permits 06070088 and 06070020 for projects by the Permittee and Gateway, respectively and cannot be used as emission reduction credits for other purposes.

b. If the Permittee proposes to rely upon emission offsets from other sources or other activities/projects, the Permittee shall

apply for and obtain a revision to Permit 06070088 prior to relying on such emission offsets, which application shall be accompanied by detailed documentation for the nature and amount of those alternative emission offsets.

5.6 Source-Wide Production and Emission Limitations

5.6.1 Emissions of Hazardous Air Pollutants

Source-wide emission limitations for HAPs as listed in Section 112(b) of the CAA are not set. This source is considered to be a major source of HAPs.

5.6.2 Other Source-Wide Production and Emission Limitations from existing permits:

a. Provisions from Construction Permit #95010001

i. Total production of iron and steel by U.S. Steel/Granite City plant shall not exceed the following limits. Compliance with these annual production limits shall be determined on a month by month basis by showing that the actual production of iron and steel from the plant did not exceed the scheduled rate of production for a month given in the most recent production schedule provided to the Illinois EPA Compliance Section and Collinsville Regional Office as provided below [T1]:

Product	Net tons/yr
Iron	3,165,000
Steel	3,580,000

A. If no production schedule is submitted to the Illinois EPA by the Permittee for a particular year, the scheduled monthly production of iron and steel shall be set at one twelfth of the annual production limits in Condition 5.6.2(a)(i) above.

B. 1. The Permittee may submit a schedule for iron and steel production for each month of the calendar year. Such schedule shall provide the scheduled monthly iron and steel production for each month and the total of such scheduled production shall not exceed the annual production limits in Condition 5.6.2(a)(i) above. This schedule shall be submitted each year no later than December 15th of the preceding year.

2. During the course of the year, the Permittee may submit a revised production

schedule which accounts for actual production levels which were below that scheduled for the previous months, provided that in no case shall the scheduled production for prior months in such a revised schedule be lowered to less than actual production levels or raised. Such revised schedule shall be submitted no later than 15 days after the first day of the month for which scheduled production has been raised. Such schedule shall be accompanied by data on actual production in preceding months.

ii. Total fuel usage for blast furnaces stoves (A and B), boilers 11 and 12, ladle drying preheaters and blast furnace gas flare #1 and shall not exceed the following limits. Compliance with the monthly limits shall be determined by direct comparison of monthly data to the applicable limit. Compliance with the annual limits shall be determined based on a calendar year [T1]:

A. Natural Gas usage:

225 million ft^3 per month and 1,346 million ft^3 per year;

B. Blast Furnace Gas (BFG) usage:

30,800 million ft^3 per month and 185,030 million ft^3 per year; and

C. Fuel Oil usage:

60,000 gallons per month and 365,000 gallons per year.

iii. A. Annual emissions from the fuel combustion units identified in Condition 5.6.2(a)(ii) above shall not exceed the following limits in tons/year:

PM/PM_{10}	SO_2*	NO_x	VOM	CO	Lead
274	641	706	2	1,295	0.06

* These limits have been addressed by an enforcement action, with a compliance schedule established for compliance with these limits. (See Condition 7.4.13)

B. Annual emissions from each individual fuel used in the fuel combustion units identified in

Condition 5.6.2(a)(ii) above shall not exceed the following limits:

1. Natural Gas

Pollutant	Emission Factor (Lbs/mmcf)	Maximum Emissions (Tons/Yr)
PM	5.1	3.43
PM_{10}	5.1	3.43
SO_2	0.6	0.40
NO_x	306.0	205.94
VOM	2.8	1.88
CO	40.0	26.92

2. BFG

Pollutant	Emission Factor (Lbs/mmcf)	Maximum Emissions (Tons/Yr)
PM	2.90	268.29
PM_{10}	2.90	268.29
SO_2	6.65*	615.22*
NO_x	5.28	488.48
CO	13.70	1,267.46

* These limits have been addressed by an enforcement action, with a compliance schedule established for compliance with these factors and limits. (See Condition 7.4.13)

3. Fuel Oil

Pollutant	Emission Factor (Lbs/Mgal)	Maximum Emissions (Tons/Yr)
PM	9.72	1.77
PM_{10}	9.75	1.77
SO_2	141.30	25.79
NO_x	55.00	10.04
VOM	0.28	0.05
CO	5.00	0.91
Lead	0.336	0.06 (Waste Oil)

C. Compliance with the annual limits in Condition 5.6.2(a)(iii) shall be determined based on a calendar year.

b. Provisions from Construction Permit #06070022:

Annual emissions of the source from combustion of COG shall not exceed the following limits [T1)]

	Limits (Tons/Year)	
	PM_{10}	SO_2
"Outage" of Affected System	47.55	530.59
Total (includes normal and outage):	224.80	807.90

c. Provisions from FESOP #94120017:

Emissions of SO_2 from the so called "sulfur dioxide emission units" operated at the source shall not exceed the following limits. Compliance with the limits shall be determined in accordance with the procedure in Condition 5.12.

Unit Operating Group	Sulfur Dioxide Emissions		
	(Lbs/3-Hours)	(Lbs/Day)	(Tons/Yr)
Slab Reheat Furnaces 1-3	2,299	9,754	987
Slab Reheat Furnace 4	---	11,873	1,204
Blast Furnace Stoves A and B	---	19,774	3,609
Boilers 11 and 12	---	20,584	3,756
Ladle Drying Preheaters	555	2,786	509
Blast Furnace Casthouse Baghouse	---	3,430	626
Iron Spout Baghouse	---	170	31

5.7 Source-Wide Testing Requirements

Pursuant to 35 IAC 201.282 and Section 4(b) of the Act, every emission source or air pollution control equipment shall be subject to the following testing requirements for the purpose of determining the nature and quantities of specified air contaminant emissions and for the purpose of determining ground level and ambient air concentrations of such air contaminants:

a. Testing by Owner or Operator: The Illinois EPA may require the owner or operator of the emission source or air pollution control equipment to conduct such tests in accordance with procedures adopted by the Illinois EPA, at such reasonable times as may be specified by the Illinois EPA and at the expense of the owner or operator of the emission source or air pollution control equipment. All such tests shall be made by or under the direction of a person qualified by training and/or experience in the field of air pollution testing. The Illinois EPA shall have the right to observe all aspects of such tests [35 IAC 201.282(a)].

b. Testing by the Illinois EPA: The Illinois EPA shall have the right to conduct such tests at any time at its own expense. Upon request of the Illinois EPA, the owner or operator of the emission source or air pollution control equipment shall provide, without charge to the Illinois EPA, necessary holes in stacks or ducts and other safe and proper testing facilities, including scaffolding, but excluding instruments and sensing devices, as may be necessary [35 IAC 201.282(b)].

c. Any such tests are also subject to the Testing Procedures of Condition 8.5 set forth in the General Permit Conditions of Section 8.

5.8 Source-Wide Monitoring Requirements

a. Requirements for coke oven gas (COG) flow meters from FESOP #94120017: for purposes of these conditions, a Unit Operating Group is a group of emission units as defined in Condition 5.6.2(c).

Note: Requirements for monitoring the sulfur content of COG as present in FESOP #94120017 are included in Section 7.3 of this CAAPP permit.

i. The Permittee shall test, operate, and maintain a system for measuring the COG usage for each unit operating group.

ii. A flow meter shall be maintained on the main Blast Furnace and Steelworks COG feed lines and each individual emission unit or unit operating group and shall be used to measure the COG usage rate. The total COG usage for each unit operating group as a whole shall be the sum of the individual usage for the emission units of that group as measured by the individual meters or that measured by a single flow meter measuring the COG usage for the unit operating group as a whole.

iii. The COG flow meter system shall be capable of recording the COG usage in standard cubic feet on an hourly and daily basis. COG usage shall be obtained from the COG flow meter system to allow the determination of hourly and/or daily COG usage for each unit operating group, as needed for the emission rate calculations of this permit.

iv. The COG flow meter system shall be operated, and data collected, reduced and maintained, in accordance with the applicable requirements of 40 CFR 60.13 and 35 Ill. Adm. Code Part 201 Subpart L.

A. Each COG flow meter shall be tested at least every 12 months, in accordance with the procedures of 40 CFR 60, Appendix B, Performance Specification 6.

B. The results of these flow meter performance tests shall be sent to the Illinois EPA's Division of Air Pollution Control, Permit Section and Regional Office within 14 days after completion of the tests. In addition, the results shall be maintained in accordance with the recordkeeping requirements specified in this permit.

C. If a single flow meter on an unit operating group fails, then the COG usage for that group may be calculated using the difference between overall total COG usage and the total COG usage at the remaining properly operating COG flow meters, or the difference in COG usage from the main COG feed line of the affected unit operating group and the COG usage at the remaining properly operating flow meters associated with that main feed line.

D. In the event that several flow meters are down such that the above COG usage calculation is not possible, the COG usage for the affected unit operating group(s) shall be determined by a method approved by the Illinois EPA (e.g., use of temporary backup measurement system). In no case shall COG usage not be determined by a method described in this permit, or an approved alternative method, so as to result in insufficient data being obtained to determine the COG usage for any unit operating group as needed to evaluate compliance using the emission rate calculations of this permit.

v. In the event of malfunction or breakdown of a COG flow meter system, the Permittee shall repair and recalibrate the meter or monitoring system as soon as practicable but no later than 10 days after the malfunction or breakdown is detected, unless prior Illinois EPA approval is obtained by submitting a notification of extended outage and adequate justification to the Illinois EPA detailing the reasons for delay. Records of repair and recalibration must be maintained in accordance with the recordkeeping requirements of this CAAPP permit. This condition does not relieve the Permittee of the minimum data obtaining requirements of this CAAPP permit.

b. The Permittee shall conduct observations at the property line of the source for visible emissions of fugitive particular matter form the source to address compliance with 35 IAC 212.301, upon request by the Illinois EPA, as follows:

For this purpose, daily observations shall be conducted for a week for particular area(s) of concern at the source, as specified in the request. Observations shall begin either within one day or three days of receipt of a written request

from the Illinois EPA, depending, respectively, upon whether observations will be conducted by employees of the Permittee or a third-party observer hired by the Permittee to conduct observations on its behalf. The Permittee shall keep records for these observations, including identity of the observer, the date and time of observations, the location(s) from which observations were made, and duration of any fugitive emissions event(s).

c. Pursuant to FESOP 94120017, the Permittee shall analyze the fuel oil used at the source in accordance with the following.

i. The sulfur content and density as determined by the ASTM methods specified in the testing requirements of FESOP 94120017 shall be used in emission calculations.

ii. The sulfur content and density of the fuel oil shall be determined upon each instance of fuel oil usage.

5.9 Source-Wide Recordkeeping Requirements

5.9.1 Records for Opacity and Emission Limits

The Permittee shall maintain the following records pursuant to Section 39.5(7)(b) of the Act:

a. The Permittee shall maintain records of the total annual net production of iron and steel on a monthly basis and a total calendar year basis, to verify compliance with Condition 5.6.2(a)(i).

b. The Permittee shall maintain records of monthly and annual use of fuels to verify compliance with Condition 5.6.2(a)(ii).

c. The Permittee shall maintain records of annual emissions from the emission units listed in Condition 5.6.2(a)(ii) for comparison to the annual emission limits in Condition 5.6.2(a)(iii)(A) for PM/PM_{10}, SO_2, NO_x, VOM, CO and lead.

d. The Permittee shall maintain the following records for the emission units identified in Condition 5.6.2(a)(ii) to verify the emission factors for different fuels listed in Condition 5.6.2(a)(iii)(B):

i. For emissions of NO_x, PM, PM_{10}, VOM, and CO, records for the emission factors used by the Permittee to determine emissions of the pollutant from the subject emission units for firing of natural gas, blast furnace gas and oil, with supporting documentation and analysis, and the "maximum" annual emission factors for the different fuels and pollutants calculated as a weighted average of the individual

factors for different emission units, weighted for the greatest relative annual use of fuel in different units, beginning with the unit that has the highest emission factor. For example, if the boilers have the highest emission factors for NO_x, the factors shall be weighted for the greatest percentage of fuels expected to be used in the boilers, and then for the units that have the next highest emission factor(s), and so forth until all of the fuel has been accounted for. These records shall be reviewed and updated by the Permittee as necessary to assure that the emission factors that it uses to determine emissions of the subject unit do not understate emissions, including review when emission testing is conducted for the subject emission units, review when emission testing of similar emission units is conducted at other facilities (as would be needed if the Permittee is relying upon data from emission testing at other US Steel facilities), and review when USEPA revises its *Compilation of Air Pollutant Emission Factors*, AP-42 (as would be needed if the Permittee has relied upon emission factors from AP-42). These records shall be prepared and copies submitted to the Illinois EPA in accordance with Condition 5.9.6(c).

ii. Records for the sulfur content of COG and BFG, as measured pursuant to Conditions 5.9.1(e) and 7.3.9(f) and Condition 7.10.8-1(c), respectively, which data shall either be used when determined SO_2 emissions from combustion of the fuels or used to confirm that the determinations of SO_2 emissions from combustion of these fuels do not understate actual SO_2 emissions.

iii. Records for the actual average annual emission rates for different fuels and pollutants, including SO_2 and lead, calculated by dividing the actual emissions of the subject units for different fuels and pollutants by the annual usage of fuels. These records shall be compiled on an annual basis by the Permittee when the records for annual emissions of the subject units are compiled.

e. The Permittee shall maintain the following records for the emissions of PM_{10}* and SO2 associated with use of COG to verify compliance with the emission limits in Condition 5.6.2(b). (See also recordkeeping requirements in Section 7.3 of the permit.)

* For the purpose of this condition, the Permittee shall address total PM_{10}, including both filterable and condensable particulate, rather than only filterable particulate.

i. Records for the volumes of COG that are and are not processed by the COG Desulfurization System (scf), with data for undesulfurized COG on a 3-hour, daily and monthly basis and data for desulfurized COG on a daily and monthly basis.

ii. Records for the sulfur contents of COG (gr/scf or gr/100 scf), with data for undesulfurized COG on a 3-hour, daily and monthly basis and data for desulfurized COG on a daily and monthly basis.

iii. Records for the emission factors used by the Permittee to determine the PM_{10} emissions from firing desulfurized and undesulfurized COG for the emission units at the facility that fire COG, with supporting documentation and analysis, and the "maximum" annual PM_{10} emission factor calculated as a weighted average of the individual factors for different emission units, weighted for the greatest relative annual use of COG in different units, beginning with the unit that has the highest emission factor. These records shall be reviewed and updated by the Permittee as necessary to assure that the emission factors that it uses to determine emissions of units firing COG do not understate emissions, including review when PM_{10} emission testing is conducted for units at the facility and review when PM_{10} emission testing of similar emission units is conducted at other facility.

iv. Records for the annual PM_{10} and SO_2 emissions from the facility from combustion of COG that has not been desulfurized, determined from the summation of the volume of such COG multiplied by either its sulfur content or the established PM10 emission factor for undesulfurized COG.

v. Records for the annual PM_{10} and SO_2 emissions from the facility from combustion of COG that has been desulfurized, determined from the summation of the volume of such COG multiplied by either its sulfur content or the established PM10 emission factor for desulfurized COG.

vi. Records for the total annual PM_{10} and SO_2 emissions from the facility from combustion of COG, determined as the sum of the annual emission from combustion of COG that has and has not been desulfurized.

5.9.2 Records for HAP Emissions

The Permittee shall maintain source-wide records of HAP emissions on a calendar year basis and individually for the emission units or group of emission units covered by Section 7 (Unit Specific Conditions for Specific Emission Units) of this

permit and emitting HAPs, pursuant to Section 39.5(7)(b) of the Act.

5.9.3 Records for Source-Wide Control Requirements and Work Practices

a. The Permittee shall keep a copy of the fugitive particulate matter operating plan, and any amendments or revisions to the plan, as required by Condition 5.3.2. The Permittee shall also keep a record of activities completed according to the plan.

b. The Permittee shall keep copy of the PM_{10} contingency plan, and any amendments or revisions as described by Condition 5.3.3. The Permittee shall also keep a record of activities completed according to the plan.

c. The Permittee shall keep a copy of the Episode Action Plan, and any amendments or revisions to the plan, as described in Condition 5.3.7. The Permittee shall also keep a record of activities completed according to the plan.

d. The Permittee shall keep a record of property line observations required by Condition 5.8(b).

5.9.4 Records to address SO_2 emission limits in Condition 5.6.2(c) from FESOP #94120017:

a. SO_2 emissions of each unit operating group in terms of the associated emission limits of this permit (i.e., lbs/3-hrs and lbs/day) accompanied by the data from which they were determined.

b. SO_2 emissions of each unit operating group in tons/month.

c. SO_2 emissions of each unit operating group in tons/year determined by using a rolling total of the previous 12 consecutive months of data.

d. Records for repairs of any COG flow meter, as required by Condition 5.8(a)(v), including copies of any notifications to the Illinois EPA for extended outage of a flow meter.

e. Records for any fuel oil usage instances with the results of the sampling and analysis of oil sulfur content.

5.9.5 The Permittee shall retain copies of all emission test reports and other test reports and other submittals to the Illinois EPA related to testing that are required by Conditions 5.7 and 5.10 and other conditions of this permit.

5.9.6 Retention, Availability and Submittal of Records

Pursuant to Section 39.5(7)(e)(ii) of the Act, the Permittee shall keep the records required by this permit as follows:

a. All records and logs required by this permit shall be retained for at least five years from the date of entry (unless a longer retention period is specified by the particular recordkeeping provision herein). The Permittee shall keep the last 3 years of data on-site and remaining 2 years data may be kept at an offsite location. The Permittee shall make all these readily accessible records available to the Illinois EPA or USEPA for inspection and/or copying upon request.

b. The Permittee shall retrieve and print, on paper during normal source office hours, any records retained in an electronic format (e.g., computer) in response to an Illinois EPA or USEPA request for records during the course of a source inspection.

c. For certain records related to emission factors or emission rates required to be kept by this permit for various emission units at this source, as specifically identified in other conditions of this permit, the Permittee shall submit a copy of the records to the Illinois EPA as provided below:

i. Copies of initial records shall be submitted to the Illinois EPA within 15 days of the date that the Permittee prepares these records for subject unit(s), which shall in no case be later than January 20, 2012.

ii. Thereafter, copies of revised records shall be submitted to the Illinois EPA with the emission test reports for subject emission unit(s) if the records were revised as a consequence of emission testing or otherwise within 15 days of the date that the Permittee completes the preparation of revised records for subject unit(s).

5.9.7 Inspection, Sampling and Observations Documentation

Inspection, sampling and observation performed as required by this permit shall have documentation in addition to the records elsewhere in this permit that identifies at least the following:

a. Name of person(s) or representative performing such activity;

b. Date and time of such activity;

c. Any applicable industry standards or other specific procedures for such activities; and

d. Any quality assurance or quality control results.

5.10 Source-Wide Reporting Requirements

5.10.1 General Source-Wide Reporting Requirements

a. Pursuant to Section 39.5(7)(f)(ii) of the Act, the Permittee shall promptly notify the Illinois EPA, Air Compliance Section, within 30 days of deviations from applicable requirements as follows:

i. Requirements in Condition 5.3.2(d) and (e)

ii. Requirements in Condition 5.5.

iii. Requirements in Condition 5.6.2.

b. All such deviations shall be summarized and reported as part of the semiannual monitoring report required by Condition 8.6.1.

c. The Permittee shall notify the Illinois EPA, Air Compliance Section, of all other deviations as part of the semiannual monitoring reports required by in Condition 8.6.1.

d. All required deviation reports described in Condition 5.10.1 above shall contain the following information:

i. Date and time of the deviation;

ii. Emission units(s)/operation involved;

iii. The duration of the event;

iv. Probable cause of the deviation;

v. Any corrective actions or preventative measures taken;

vi. Reporting on malfunction and breakdown shall be performed in accordance with Condition 5.10.5; and

vii. Reporting on startup shall be performed in accordance with Condition 5.10.5.

5.10.2 Annual Emissions Report

a. The annual emissions report required pursuant to Condition 9.7 shall contain emissions information, including HAP emissions, for the previous calendar year.

b. The Permittee shall submit the following additional information from the prior calendar year with the Annual Emissions Report, due May 1st of each year, pursuant to Permit 95010001:

i. Iron and steel production (tons/month and tons/yr, each);

ii. Natural gas and BFG usage ($mmft^3$/month and $mmft^3$/yr, each); and

iii. Fuel oil usage (thousand gallons/month and thousand gallons/yr, for each type of oil).

c. The Permittee shall submit an annual report to the Illinois EPA with its Annual Emission Report describing the implementation of the Road Cleaning Program for the affected road segments, as defined in Condition 7.13.5(d), during the previous year. This report shall at a minimum provide: the number of times each road segment was cleaned; the number of times that scheduled cleaning was not performed, with explanation; a description of any significant changes in road cleaning equipment or cleaning practices, with explanation; and a description of other significant changes to the Program, including changes in contractors [Permit #06070088].

5.10.3 Reporting requirements from FESOP #94120017

a. The Permittee shall submit quarterly reports (every 3 calendar months) to the Illinois EPA. This report is due 30 days after the end of the reporting period and may be submitted on computer disk. This report shall contain the following information for the days during the quarter:

i. A summary showing the emissions of SO_2 for each unit operating group for each day and the 12 month rolling average in tons/year.

ii. A statement identifying any apparent violations which occurred during the quarter covered by the report or, if there have been no apparent violations, a statement to that effect.

iii. A summary of any COG flow meter downtime.

iv. Identification of any days for which data for at least 75% of the operating hours of the unit operating group was not obtained by an approved method; justification for not obtaining the data; and description of corrective action taken.

b. These reports shall be sent to IEPA Compliance Section in Springfield and IEPA Regional Office in Collinsville.

c. Copies of the Final Report for the tests identified in Condition 5.8(a)(iv) shall be submitted to the Illinois EPA along with the quarterly reports required by this CAAPP permit within 30 days after the reported quarter.

5.10.4 Other Source-Wide Reporting Requirements

a. i. A quarterly report shall be submitted to the Illinois EPA stating the following: the dates any necessary control measures were not implemented, a listing of those control measures, the reasons that the control measures were not implemented, and any corrective actions taken. This information includes, but is not limited to, those dates when controls were not applied based on a belief that application of such control measures would have been unreasonable given prevailing atmospheric conditions, which shall constitute a defense to the requirements of this Section. This report shall be submitted to the Illinois EPA thirty (30) calendar days from the end of a quarter. Quarters end March 31, June 30, September 30, and December 31 [35 IAC 212.316(g)(5)].

ii. The reporting requirements from the above are established for fugitive particulate matter control measures implemented for the certain operations identified in 35 IAC 212.316(b) through 212.316(f).

iii. Control measures for this condition are those identified in the Fugitive Particulate Matter Operating Program.

b. Upon written request by the Illinois EPA, a report shall be submitted to the Illinois EPA for any period specified in the request stating the following: the dates during which any process emission unit was in operation when the air pollution control equipment was not in operation or was not operating properly, documentation of causes for pollution control equipment not operating or not operating properly, and a statement of what corrective actions were taken and what repairs were made [35 IAC 212.324(g)(6)].

5.10.5-1 Reporting for Startups (State Authorization)

Pursuant to 39.5(7)(a) and (f)(ii) of the Act, when startup reports are required for an emission unit by unit specific conditions in Chapter 7 of this permit, such reports shall be submitted to the Illinois EPA, Air Compliance Section and Collinsville Regional Field Office on a semi-annual basis, and include the following information related to startups of such emission unit and associated air pollution control equipment.

a. If startups occurred during the reporting period, the report shall include the following:

i. The number of startups.

ii. The number of departures from established procedures.

iii. The number of exceedances of each applicable standard.

iv. A general explanation for the magnitude of the numbers reported and the significance or meaning of those numbers.

v. A general explanation for the departures.

vi. A general explanation for the exceedances.

vii. A general discussion of whether any improvements were made to startup practices

b. If there were no startups for the reporting period, a statement that "No startups occurred during this reporting period."

c. Startups that resulted in excess emissions shall be addressed in the deviation reports as required by unit specific conditions in Chapter 7 of this permit.

5.10.5-2 Reporting for Malfunction or Breakdown (State Authorization)

a. The Permittee shall provide the following notification and reports to the Illinois EPA, Air Compliance Section and Collinsville Regional Field Office, pursuant to 35 IAC 201.263, concerning continued operation of an affected emission unit or related air pollution control equipment when such continued operation would cause a violation of a standard or limitation in 35 IAC Subtitle B, Chapter I, subchapter c:

i. If an emission unit or control device operates during a malfunction/breakdown, the Permittee shall immediately report such event to the Illinois EPA within 2 working days after such event occurs. The immediate notification shall be provided to the Illinois EPA's Springfield Office (Compliance Section) by a telephone, facsimile, electronic mail or other alternative method of correspondence that constitutes the fastest available alternative. The immediate notification shall be followed by a letter to the Illinois EPA's Springfield Office (Compliance Section), postmarked within 7 working days after the end of the event. The 7 day follow-up letter shall contain the name, title, and signature of the owner or operator or other responsible official certifying its accuracy, explaining the circumstances and reasons for event, describing all excess emissions and/or parameter monitoring exceedances which may have occurred during the malfunction/breakdown event, actions taken to minimize emissions or parameter exceedance and all repairs made in conjunction with such malfunction/breakdown event.

ii. If all the necessary information identified above is contained within the 2-day immediate notification and the notification was done by means of written correspondence, a 7-day follow-up letter is not required to be submitted.

iii. A summary of these malfunction/breakdown reports required by this permit shall be submitted to the Illinois EPA's Springfield Office Compliance Section on a quarterly basis and contain the following:

A. Date and time of malfunction/breakdown;

B. Emission unit(s)/control involved;

C. The duration of the event;

D. Probable cause of malfunction/breakdown; and

E. Repairs and other corrective actions taken.

5.10.5-3 Federal Startup Shutdown and Malfunction/Breakdown Requirements

a. For those emission units subject to a NESHAP standard and for which an SSM plan is required under 40 CFR 63.10(d)(5), the Permittee shall submit reports as required by the NESHAP including:

i. Periodic startup, shutdown or malfunction reports [40 CFR 63.10(d)(5)(i)]

A. 1. If actions taken by an owner or operator during a startup or shutdown (and the startup or shutdown causes the affected emission unit to exceed any applicable emission limitation in the relevant NESHAP emission standards specified in Section 7 of this permit), or malfunction of an affected emission unit (including actions taken to correct a malfunction) are consistent with the procedures specified in the source's startup, shutdown, and malfunction plan (see 40 CFR 63.6(e)(3)), the Permittee shall state such information in a startup, shutdown, and malfunction report.

2. Actions taken to minimize emissions during such startups, shutdowns, and malfunctions shall be summarized in the report and may be done in checklist form; if actions taken are the same for each event, only one checklist is necessary.

3. Such a report shall also include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.

B. The startup, shutdown, and malfunction report shall consist of the following:

A letter, containing the name, title, and signature of the owner or operator or other responsible official who is certifying its accuracy.

C. Reports shall only be required if a startup, shutdown or malfunction occurred during the reporting period.

D. The SSM Report shall be submitted to the Illinois EPA semiannually and shall be delivered or postmarked by the 30th day following the end of each calendar half (or other calendar reporting period, as appropriate).

E. If the owner or operator is required to submit excess emissions and continuous monitoring system performance (or other periodic) reports required by this permit, the startup, shutdown, and malfunction reports required under 40 CFR 63.10(d) may be submitted simultaneously with the excess emissions and continuous monitoring system performance (or other) reports.

F. If startup, shutdown, and malfunction reports are submitted with excess emissions and continuous monitoring system performance (or other periodic) reports, and the owner or operator receives approval to reduce the frequency of reporting for the latter under 40 CFR 63.10(e), the frequency of reporting for the startup, shutdown, and malfunction reports also may be reduced if the Illinois EPA does not object to the intended change. The procedures to implement the allowance in the preceding sentence shall be the same as the procedures specified in 40 CFR 63.10(e)(3).

ii. Immediate startup, shutdown or malfunction reports [40 CFR 63.10(d)(5)(ii)]

A. Notwithstanding the allowance to reduce the frequency of reporting for periodic startup,

shutdown, and malfunction reports under 40 CFR 63.10(d)(5)(i), any time an action taken by an owner or operator during a startup or shutdown that caused the source to exceed any applicable emission limitation in the relevant NESHAP emission standards specified in Section 7 of this CAAPP, or malfunction (including actions taken to correct a malfunction) is not consistent with the procedures specified in the affected source's startup, shutdown, and malfunction plan, the owner or operator shall submit an immediate report stating the actions taken for that event within 2 working days after commencing actions inconsistent with the plan and a follow-up report submitted within 7 working days after the end of the event.

B. The immediate report shall consist of a telephone call (or facsimile (FAX) transmission) to the Illinois EPA.

C. The follow-up report shall consist of the following:

1. The name, title, and signature of the owner or operator or other responsible official who is certifying its accuracy and explaining the circumstances of the event.

2. The reasons for not following the startup, shutdown, and malfunction plan.

3. Description all excess emissions and/or parameter monitoring exceedances which are believed to have occurred (or could have occurred in the case of malfunctions).

4. And actions taken to minimize emissions in conformance with 40 CFR 63.6(e)(1)(i).

5.10.6 Separate copies of all reports required by this permit shall be sent to the IEPA Regional Office in Collinsville.

5.10.7 <u>40 CFR 63, Subpart DDDDD (Notification of Compliance)</u>

a. Pursuant to 40 CFR 63.7545(b), the Permittee must submit an initial Notification according to 40 CFR 63.9(b)(2).

b. Pursuant to 40 CFR 63.7545(e), the Permittee must submit a Notification of Compliance Status according to 40 CFR 63.9(h)(2)(ii). For the initial compliance demonstration for each affected unit, the Permittee must submit the Notification of Compliance Status, including all

performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for the affected unit according to 40 CFR 63.10(d)(2).

c. For subject emission units, for which Permittee must conduct an initial compliance demonstration, the report shall include the information specified in 40 CFR 63.9(h)(2) and 63.7545(e).

d. In addition to the information required by 40 CFR 63.9(h)(2), the notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

i. "This facility complies with the requirements in 40 CFR 63.7540(a)(10) to conduct an annual or biennial tune-up, as applicable, of each unit."

ii. "This facility has had an energy assessment performed according to 40 CFR 63.7530(e)."

iii. "No secondary materials that are solid waste were combusted in any affected unit."

e. Pursuant to 40 CFR 63.7530(e), the Permittee must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 of 40 CFR Part 63, Subpart DDDDD and is an accurate depiction of the affected facility.

f. Pursuant to 40 CFR 63.7530(d), the Permittee must submit a signed statement in the Notification of Compliance Status report that indicates a tune-up was completed on each existing unit firing natural gas with a heat input capacity of less than 10 million Btu per hour.

5.11 Source-Wide Operational Flexibility/Anticipated Operating Scenarios

No source-wide operational flexibility/anticipated operating scenarios have been established in this permit.

5.12 Source-Wide Compliance Procedures

Compliance Provisions for Condition 5.6.2(c) (adopted from FESOP 94120017):

a. Compliance with the lbs/3-hours limits in Condition 5.6.2(c) shall be demonstrated by using emission rate calculations for eight discrete 3-hour periods per day, with the first period beginning at midnight.

b. Compliance with the daily emission limits in Condition 5.6.2(c) shall be demonstrated by using emission rate calculations on a daily block basis (i.e., midnight to midnight).

c. The compliance calculations shall be the primary compliance method for determining compliance with the emission limits in Condition 5.6.2(c), except for the blast furnace casthouse baghouse and iron spout baghouse, for which stack testing shall be the primary means of determining compliance.

d. Total SO_2 emissions from an unit operating group for determination of compliance with the SO_2 limits in Condition 5.6.2(c) shall be the sum of the emissions resulting from the use of COG and fuel oil at the unit operating group, i.e.:

Lbs SO_2 per unit operating group = SO_2 emissions from fuel oil usage + SO_2 emissions from COG usage

Note: When FESOP Permit 94120017 was originally issued, the SO_2 emissions which would result from the use of blast furnace gas and natural gas in the unit operating groups were accounted for in the SO_2 limits of that permit. This was accomplished by lowering the permitted SO_2 from the SO_2 levels used for air quality modeling by an amount equal to the SO_2 which would have been emitted should the unit operating groups use blast furnace gas or natural gas continuously. The SO_2 emissions from blast furnace gas and natural gas were calculated using standard emission factors as found in AIRS Facility Subsystem, Source Classification Codes and Emission Factor Listing for Criteria Air Pollutants, EPA Document Number EPA 450/4-90-003, and Compilation of Air Pollution Emission Factors, Vol. 1, Stationary Point and Other Sources, AP-42.

e. The SO_2 emissions attributable to fuel oil usage shall be calculated from the records required by the CAAPP permit for usage of fuel oil and the sulfur and heat content of oil (See Condition 5.9.4) and the following equation:

Lbs SO_2/period = gallons of oil burned per period x sulfur content in weight percent of the fuel oil used x density of the fuel oil used in pounds per gallon x 2.

f. The SO_2 emissions attributable to COG usage shall be calculated from the records required by the CAAPP permit for the amount of COG burned and the sulfur content of the COG (See Condition 5.9.1(e)) and the following equation:

Lbs SO_2/period = thousand standard cubic feet of COG burned per period x average H_2S content of the COG in grains per standard cubic foot for the period x 0.269.

g. Stack test measurement shall be the primary method of determining the compliance of the Blast Furnace Casthouse and Iron Spout Baghouse with the lbs/day limits in Condition 5.6.2(c). The secondary means of determining compliance shall be the following:

i. The SO_2 attributable to the Blast Furnace Casthouse Baghouse shall be calculated using an emission factor of 0.173 lbs SO_2 per ton of hot metal cast.

ii. The SO_2 attributable to the Iron Spout Baghouse shall be calculated using an emission factor of 0.0063 lbs SO_2 per ton of hot metal cast.

h. Compliance with the tons/yr limits in Condition 5.6.2(c)) shall be determined using a rolling total of 12 consecutive calendar months of data.

i. When fuel oil is used and data is not available for the fuel oil at the individual unit operating groups, the oil usage during such period shall be calculated from the data for total usage of oil apportioned among the individual operating groups using oil based on the relative heat inputs the unit operating group during that period.

j. Usage of COG shall be determined from data collected by the COG flow meters.

Note: For this purpose, data from flow meters for both desulfurized and undesulfirized COG may be used in accordance with Condition 5.9.1(e)(i).

k. The average H_2S content of COG for the lbs/3-hours compliance calculations shall be calculated using an arithmetic average of all available H_2S data during the 3-hour period that COG was burned. In the event that the H_2S monitoring system is unable to obtain a single reading for the 3-hour period, the H_2S content for that 3-hour period shall be obtained by one of the alternative methods specified in Condition 7.3.9(f) of this permit (i.e., manual sampling of H_2S content or determined by type of coal used during that period and previous recorded H_2S content when using this coal type).

For this purpose, data from H_2S monitoring systems for both desulfurized and undesulfurized COG, in accordance with Condition 5.9.1(e)(ii), shall be used as appropriate depending upon whether desulfurized or undesulfurized COG is being combustion.

l. The daily average H_2S content of COG for use in the lbs/day compliance calculations shall be calculated using an arithmetic average of all available hourly average H_2S content data for

that day, and at least data from 75% of the daily operating hours.

Note: For this purpose, data from the H_2S monitoring systems for both desulfurized and undesulfurized COG, in accordance with Condition 5.9.1(e)(ii).

5.13 General Procedures for Certain Permit Limits on Emissions

Pursuant to Sections 39.5(7)(b) and (p)(v) of the Act, these procedures are applicable for the emission limits in Conditions 7.1.6(b)(i) through (iv), 7.4.6(b) through (f), 7.5.6(c) through (g) and 7.6.6(a) through (e), which address the rates of emissions or "emission factors" (commonly in pounds/ton) and the annual emissions or "maximum emissions" (in tons/year) of certain emission units, as the Permittee determines compliance with these limits with "emission factors," using the common meaning of this term. In particular, notwithstanding the fact that the above listed conditions set "emission factor limits" or limits on the rates of emissions, for purposes of this condition, an "emission factor" is a set value for the mass of a pollutant emitted by a particular emission unit relative to the amount of material that is processed or handled by the unit, or in the case of lead, a set value for the mass of lead emissions for each hour that the particular unit operates, which value is used in the determination of the emissions of the unit.

Note: For the emission units (i.e., operations and processes) that are subject to the above emission limits, Conditions 7.1.9(h), 7.4.9(h)(vii) and (i), 7.5.9(f) and (g), and 7.6.9(c) require the Permittee to keep records for the emissions factors that it is using to determine compliance with these emission limits, along with records for the emissions of these units. The specific emission factors being used by the Permittee for the various subject units, based on information provided by the Permittee as of the date of issuance of this revised permit, are found in Attachment 3 of this permit.

a. The emission factors used by the Permittee to determine compliance with these emission limits shall not understate actual emissions.

b. Compliance with these emission limits shall be determined as follows. For terms that are expressed in pounds per ton or, for lead, pounds per hour (i.e., the same terms as the relevant emission factor), compliance shall be determined by comparison against the relevant emission factor for the unit and mode of operation, as applicable. For each annual limit, compliance shall be determined by comparison against the annual emissions of the unit, calculated as the product of the actual annual operation of the unit and the relevant emission factor. If more than one emission factor is needed to address the actual annual emissions of a unit, to address different modes of operation, the annual emissions of the unit shall be calculated as the sum of the annual emissions, calculated as above, for each mode of operation of the unit for which there is a different emission factor. If there are additional emissions that are not accounted

for by the established emission factor(s), these additional emissions shall also be included in the calculation of annual emissions.

c. The Permittee shall, at a minimum, review and, if necessary, update the relevant emission factors that it is using as follows, to assure that the emission factors that it uses to calculate emissions for purposes of determining compliance with these limits are appropriate, i.e., do not understate actual emissions.

i. For emission units that are subject to limits for which emission testing is required to be conducted by this permit, whenever such testing is conducted, relevant emission factors shall be reviewed based on the results of such testing and, if necessary, updated based on those results.

ii. For emission units that are subject to limits for which emission testing is not required to be conducted by this permit, the relevant emission factors shall be reviewed and, if necessary, updated on at least an annual basis, considering new information on emissions of such units that has become available, including revisions of USEPA's *Compilation of Air Pollutant Emission Factors*, AP-42, other information published by USEPA, information related to other emission units operated by U.S. Steel, information presented in specific papers and reports concerning the steel industry, and other salient information.

d. The Permittee shall comply with the following reporting requirements related to the emission factors that it is using to determine compliance with these emission limits:

i. If the Permittee updates the emission factors that it is using, as a result of its review of the relevant emission factors, as provided for by Condition 5.13(c)(i) or (ii), copies of the revised records for such emission factor(s) shall be submitted to the Illinois EPA in accordance with Condition 5.9.6(c)(ii).

ii. At the same time that it submits its Annual Emission Report, as addressed by Condition 5.10.2, the Permittee shall also submit a report confirming its review of relevant emission factors in accordance with Condition 5.13(c)(i) and (ii) during the previous year, which report shall, for each applicable emission limit, include an identification of the testing conducted during the previous year, if any, or a description of all new information that was considered, if any, and the findings and conclusion of its review of such information and any updates that it made to the emission factors that it uses, with explanation.

e. Upon written notification from the Illinois EPA or USEPA that it has determined one or more of the following, the Permittee shall conduct appropriate further review for the emission factor(s)

that are the subject of such notification and submit a written response to the Illinois EPA and, if applicable, USEPA within 45 days, which response may be accompanied by updates to those emission factor(s).

i. The Permittee's records for the applicable emission factor(s), as addressed by Condition 5.9.6(c)(ii) or 5.13(d)(i) do not contain adequate documentation for the selected emission factor(s).

ii. The Permittee's report pursuant to Condition 5.13(d)(ii) does not provide adequate explanation for the updates that were made to the emission factor(s).

iii. The emission factor(s) used by the Permittee do not appear to appropriately address a new mode of operation of the subject unit.

iv. There is new information, as described in or included with the notification, that appears pertinent that the Permittee has not considered in its review for the emission factor(s).

5.14 Source-wide State-Only Conditions

5.14.1 Permitted Emissions for Fees

Emission limitations are not set for the source for the purpose of permit fees. The Permittee shall pay the applicable fee pursuant to Section 39.5 of the Act.

6.0 CONDITIONS FOR EMISSIONS CONTROL PROGRAMS

This section is reserved for emissions control programs. As of the date of issuance of this permit, there are no such programs applicable to this source.

7.0 UNIT SPECIFIC CONDITIONS FOR SPECIFIC EMISSION UNITS

7.1 Material Handling and Processing Operations

7.1.1 Description

Coal handling systems:

The crusher is mainly used in the winter to break-up frozen chunks of coal to prepare the coal to be processed in the pulverizer.

There are two coal pulverizers. Only one pulverizer can be used at any one time. The remaining pulverizer is maintained as a backup unit. The pulverizers reduce the size of the coal to prepare it for the coking process. A baghouse controls the discharge outlets of the coal pulverizers.

Blast furnace raw material handling systems:

Raw materials such as coke, iron-bearing materials, and fluxes are charged to blast furnaces in the iron making process. The materials are charged in the top of the furnace from skip cars, which are filled in the stockhouse from conveyors or hoppers. Iron pellets and coke are screened prior to charging.

New Coke Conveyance System:

The new coke conveyor system transfers coke from Gateway Energy to US Steel to be used in the existing Blast Furnaces.

Steel making system:

Raw materials used in the BOFs and LMF are delivered to the facility by both truck and railcar. The trucks and railcars are either unloaded to the ground or directly into an underground feed hopper. Materials unloaded to the ground are placed in storage piles, or in super sacks, endloaders are used to transfer the materials from the storage piles or super sacks to the underground feed hopper. The underground feed hopper then feeds material onto BOF material transfer conveyor C-1. This material transfer is controlled by the Trackhopper Baghouse, this bag house empties back onto C-1 conveyor.

Materials added in the BOF and LMF are transferred from the underground feed hopper, by a conveyor system consisting of three conveyors (nos. C-1, C-2, and C-3) arranged in series. From conveyor C-3 the materials are offloaded into storage bins 1 thru 10, or a rotating hopper known as the lazy susan, or onto conveyor C-5. The storage bins unload materials to conveyor C-4, which transfers and off-loads the materials into the BOF feed hoppers for #1 vessel or #2 vessel. The lazy susan feeds directly into the BOFs Alloy transfer car. Conveyor C-5 transfers materials to the LMF material handling system. All operations carried out within this unit take place within

enclosed structures. The transfer from conveyors C-1 to C-2 and C-2 to C-3 are controlled by the Binfloor Baghouse, this bag house empties into Bin #2.

Materials are transferred from the BOF Binfloor to the LMF on conveyor C-5. This conveyor off-loads into storage bins which transfer to conveyor C-6. The emissions from the transfer from conveyor C-5 to C-6 are handled by Baghouse #1. Additional raw materials used in the LMF are transferred from the Tripper Conveyor to a set of storage bins. Emissions generated by loadout of the Tripper Conveyor are controlled by Baghouse #2.

Note: This narrative description is for informational purposes only and is not enforceable.

7.1.2 List of Emission Units and Air Pollution Control Equipment

Area	Emission Unit Description	Emission Control Equipment	Date Constructed
Coal Handling and Processing	Coal Crusher	None	Pre-1974
	Coal Pulverizers (2)	Baghouse	
	Conveyors	None	
Blast Furnace	Screens (3) • Two Coke • One Iron Pellet	None	Pre-1974
	Conveyors and Feed Hoppers	None	
	Stock House Storage Bins	None	
	New Coke Conveyance System • Conveyors and Hoppers • Day Bins	Baghouses	2009
Steelmaking	Dump Pit Conveyor	Trackhopper Baghouse	Pre-1974
	Conveyors and Storage Bins	Bin floor Baghouse	
	LMF Conveyors and Storage Bins	Baghouse #1	Prior to 1986

7.1.3 Applicable Provisions and Regulations

a. i. The "affected material handling operations" for the purpose of these unit-specific conditions, are the emission units described in Conditions 7.1.1 and 7.1.2.

ii. The "affected crushing operations" for the purpose of these unit-specific conditions, are the crusher and pulverizers described in Conditions 7.1.1 and 7.1.2.

iii. The "affected screening operations" for the purpose of these unit-specific conditions, are the iron

pellet and coke screens described in Conditions 7.1.1 and 7.1.2.

iv. The "affected transfer operations" for the purpose of these unit-specific conditions, are the conveyors, storage bins, new coke conveyance system and feed hoppers described in Conditions 7.1.1 and 7.1.2.

b. Pursuant to 35 IAC 212.316(b), the Permittee shall not cause or allow fugitive particulate matter emissions generated by the affected crushing and screening operations to exceed an opacity of 10 percent.

c. Pursuant to 35 IAC 212.316(f), the Permittee shall not cause or allow fugitive particulate matter emissions generated by the affected transfer operations to exceed an opacity of 20 percent.

d. Pursuant to 35 IAC 212.321(a), the Permittee shall not cause or allow the emission of particulate matter into the atmosphere in any one hour period from the new coke conveyor system or LMF conveyors and LMF storage bins for which, either alone or in combination with the emission of particulate matter from all other similar process emission units for which construction or modification commenced on or after April 14, 1972, at a source or premises, exceeds the allowable emission rates specified in subsection (c) of 35 IAC 212.321 (see also Attachment 2).

e. Pursuant to 35 IAC 212.322(a), the Permittee shall not cause or allow the emission of particulate matter into the atmosphere in any one hour period from any affected material handling operation for which construction or modification commenced prior to April 14, 1972*, which, either alone or in combination with the emission of particulate matter from all other similar process emission units at a source or premises, exceeds the allowable emission rates specified in subsection (c) of 35 IAC 212.322 (see also Attachment 2).

* The new coke conveyor system and LMF conveyors and LMF storage bins constructed after April 14, 1972, is not subject to 35 IAC 212.322.

f. Pursuant to 35 IAC 212.458(b)(7) and (c), the Permittee shall not cause or allow emissions of PM10, other than that of fugitive particulate matter, into the atmosphere from any affected material handling operation to exceed 0.01 gr/scf during any one hour period, except for this mass emission limit shall not apply to those emission units with no visible emissions other than that of fugitive particulate matter; however, if a stack test is performed, this subsection is not a defense to a finding of a violation of the mass emission limits contained in this condition.

7.1.4 Non-Applicability of Regulations of Concern

The emission limitations of 35 IAC 212.324 are not applicable to the affected material handling operations, as provided by 35 IAC 212.324(a)(3), because the affected operations are subject to standards in 35 IAC Part 212, Subpart R, "Primary and Fabricated Metal Products and Machinery Manufacture".

7.1.5 Control Requirements and Work Practices

a. The affected material handling operations shall be operated under the provisions of a fugitive particulate matter operating program consistent with the provisions of 35 IAC 212.309, 212.310 and 212.312 (see also Condition 5.3.2(a)) [35 IAC 212.309].

b. Pursuant to 35 IAC 212.307, material collected by control equipment on the affected material handling operations shall be handled in accordance with Condition 5.3.2(e).

c. For the air pollution control equipment on the affected operations, the Permittee shall comply with maintenance and repair requirements in 35 IAC 212.324(f), as follows, pursuant to 35 IAC 212.458(d):

The Permittee shall maintain and repair all air pollution control equipment in a manner that assures that the emission limits and standards in 35 IAC 212.458 shall be met at all times. Proper maintenance shall include the following minimum requirements:

i. Visual inspections of air pollution control equipment;

ii. Maintenance of an adequate inventory of spare parts; and

iii. Expeditious repairs, unless the emission unit is shutdown.

d. BACT/LAER requirements for the new coke conveyor system, from Permit 06070088:

i. PM and PM_{10} emissions from the day bins shall be controlled by [T1]:

A. Enclosure of the day bin so as to prevent visible fugitive emissions, as defined by 40 CFR 60.671.

B. Aspiration of the day bins or the enclosure in which they are enclosed to a control device, which device shall be operated in accordance with good air pollution control practice to

minimize emissions. For this purpose, the control device shall be a baghouse or other filtration type device unless the Permittee demonstrates and the Illinois EPA concurs that another type of control device is preferable due to considerations of operational safety.

ii. PM and PM_{10} emissions from the new coke conveyance system shall be controlled by enclosure so as to prevent visible fugitive emissions, as defined by 40 CFR 60.671 [T1].

iii. Emissions of PM and PM_{10} from the control devices for the new coke conveyance system shall not exceed 0.005 gr/dscf [T1].

Condition 7.1.5(d) represents the application of Best Available Control Technology and Lowest Achievable Emission Rate.

7.1.6 Production and Emission Limitations

a. Production and emission limits for the new coke conveyor system from Permit 06070088:

i. The new coke conveyance system shall not transfer more than 740,000 tons of coke per year [T1].

ii. The emissions from the new coke conveyance system shall not exceed 0.95 tons/year of PM and 0.45 tons/year of PM_{10} [T1].

iii. Compliance with the annual limits of Condition 7.1.6(a) shall be determined on a monthly basis from the sum of the data for the current month plus the preceding 11 months (running 12 month total) [T1].

b. Emission limits for blast furnace and steel making material handling operations from Permit 95010001:

i. Emissions from Material HS and Deslagging Station shall not exceed the following limits [T1]:

Pollutant	Emission Factors (Lbs/Ton of steel)	Maximum Emissions (Tons/Yr)
PM	0.00355	6.35
PM_{10}	0.00355	6.35

ii. BOF Additive System (Trackhopper Baghouse) emissions shall not exceed the following limits [T1]:

Pollutant	Emission Factors (Lbs/Ton of steel)	Maximum Emissions (Tons/Yr)
PM	0.00032	0.57
PM_{10}	0.00032	0.57

iii. Flux conveyor & transfer points (Bin Floor Baghouse) emissions shall not exceed the following limits [T1]:

Pollutant	Emission Factors (Lbs/Ton of steel)	Maximum Emissions (Tons/Yr)
PM	0.0016	2.86
PM_{10}	0.0016	2.86

iv. Iron Pellet Screen emissions shall not exceed the following limits [T1]:

Pollutant	Emission Factors (Lbs/Ton Iron)	Maximum Emissions (Tons/Yr)
PM	0.00279	6.01
PM_{10}	0.00279	6.01

v. Compliance with the annual limits in Condition 7.1.6(b) shall be determined based on a calendar year [T1].

7.1.7 Testing Requirements

The following emission tests and opacity observations shall be conducted pursuant to Section 39.5.(7)(d) and (p) of the Act.

a. i. The Permittee shall measure the opacity from the affected crushing, screening and transfer operations unless prolonged weather conditions preclude scheduled observations. These observations shall be conducted by a qualified observer in accordance with Method 9, as further specified below, pursuant to Section 39.5(7)(d) of the Act.

A. This testing shall be conducted at least annually.

B. Upon written request by the Illinois EPA, such testing shall be conducted for specific affected operation(s) within 45 calendar days of the request or by the date agreed upon by the Illinois EPA, whichever is later. At least 30 days prior to the scheduled test date, the Permittee shall submit a detailed test plan to

the Illinois EPA, describing the manner of operation of the affected activity and all control measures that will be implemented during the testing. The results of the testing will be submitted within thirty calendar days of the completion of the tests.

ii. The duration of opacity observations for each test shall be at least 30 minutes (five 6-minute averages).

b. The Permittee shall test for opacity and PM/PM10 emissions from the baghouse for the coal pulverizers and either the trackhopper baghouse, bin floor baghouse or baghouse #1 as will be specified by the Illinois EPA within 30 days of receipt of the test protocol. These two tests shall be completed within 30 months of the effective date of this permit condition. The Permittee shall use the following methods:

Location of Sample Points	Method 1
Gas Flow and Velocity	Method 2, 2A - H
Flue Gas Weight	Method 3, 3A - C
Moisture	Method 4
PM/PM_{10} as provided for by 35 IAC 212.108	Method 5, 201 or 201A

7.1.8 Monitoring Requirements

The Permittee shall perform the following inspections, pursuant to Section 39.5(7)(p)(ii) of the Act:

a. Affected material handling operations other than the new coke conveyance system.

The Permittee shall perform quarterly inspections of the control measures, while the affected material handling operations are in use. For purposes of this condition, all affected material means each type of material handled. Types of material are materials such as: 1) coal; 2) coke; 3) limestone; 4) iron pellets; 5) alloy materials; 6) desulfurization reagents; and 7) slag materials. These inspections shall, at a minimum, include the following:

i. Verification that control measures, including reliance on characteristics of materials, is being properly implemented. For conveyors, these inspections shall include, where applicable, verification that all covers, enclosures and dribble pans are present and in good working condition. For crushers, these inspections shall also include verifications for choke feeding.

ii. For the baghouses on the affected material handling operations - a check of differential pressure and

inspection of the dust removal system, compressed air system, bag condition, fan condition and structural components.

iii. As part of the inspections, the Permittee shall perform observations for visible emissions by Method 22. These observations shall be conducted during the operations of each activity for a minimum of 18 minutes, or for activities that operate on a batch basis, for a minimum of six consecutive batches or 18 minutes. If visible emissions are observed, the Permittee shall take corrective action within 2 hours to return the status of the operations to no visible emissions or observations of opacity by Method 9 shall be conducted. For the purpose of this condition, returning the status of operations to no visible emissions does not include, for any activity, temporary idling or the lack of operations between batches.

b. Affected new coke conveyance system

i. The Permittee shall conduct inspections of the new coke conveyor system on at least a monthly basis for the specific purpose of verifying that control measures required to control emissions from the new coke conveyor system are being properly implemented.

ii. These inspections shall include observation for the presence of visible emissions, performed in accordance with USEPA Method 22, from the conveyors and day bins.

7.1.9 Recordkeeping Requirements

The Permittee shall maintain records of the following items, pursuant to Sections 39.5(7)(a) and (e) of the Act:

a. The Permittee shall keep the following file(s) and log(s):

File(s) containing the following information for the affected material handling operations with supporting information:

i. Information related to the dust collection equipment associated with the affected operations, including design control efficiency or performance specifications and maximum design particulate matter emissions, gr/dscf.

ii. The maximum design capacity of each operation, (tons/hr).

b. For the air pollution control equipment on affected operations, the Permittee shall keep the following records

related to maintenance and repair, as required by 35 IAC 212.458(d):

i. Records of inventory of spare parts and documentation of inspections, maintenance, and repairs of all air pollution control equipment shall be kept in accordance with 35 IAC 212.324(f) [35 IAC 212.324(g)(1)].

ii. Records documenting any period during which any process emission unit was in operation when the air pollution control equipment was not in operation or was malfunctioning so as to cause an emissions level in excess of the emissions limitation. These records shall include documentation of causes for pollution control equipment not operating or such malfunction and shall state what corrective actions were taken and what repairs were made [35 IAC 212.324(g)(2)].

iii. A written record of the inventory of all spare parts not readily available from local suppliers shall be kept and updated [35 IAC 212.324(g)(3)].

c. The Permittee shall keep the written records required by 35 IAC 212.316(g)(1) as follows:

i. For fugitive particulate matter emission units subject to 35 IAC 212.316, records related to the application of control measures for compliance with the opacity limitations of 35 IAC 212.316, including submittals to the Illinois EPA an annual report containing a summary of the information in these records.

ii. These records shall include at least the information specified by 35 IAC 212.316(g)(2), as follows:

A. The name and address of the source;

B. The name and address of the owner and/or operator of the source;

C. A map or diagram showing the location of all emission units controlled;

D. For application of physical or chemical control agents: the name of the agent, application rate and frequency, and total quantity of agent, and, if diluted, percent of concentration, used each day; and

E. A log recording incidents when control measures were not used and a statement of explanation.

iii. These records shall be handled as follows:

A. Copies of all records required by 35 IAC 212.316 shall be submitted to the Illinois EPA within ten (10) working days after a written request by the Illinois EPA and shall be transmitted to the Illinois EPA by a company-designated person with authority to release such records [35 IAC 212.316(g)(3)].

B. The records required under 35 IAC 212.316 shall be kept and maintained for at least five (5) years at the source and be available for inspection and copying by Illinois EPA representatives during working hours [35 IAC 212.316(g)(4)].

d. The Permittee shall maintain records for:

i. The amount of coke handled by the new coke conveyor system (tons/month and tons/year).

ii. The amount of iron pellets screened (tons/month and tons/year).

e. The Permittee shall maintain the following records for the inspections required by Condition 7.1.8:

i. For the inspections required by Condition 7.1.8(a) for each affected material handling operation:

A. Date and time the inspection was performed and name(s) of inspection personnel.

B. The observed condition of the control measures for each affected operation, including the presence of any visible emissions or accumulations of dust in the vicinity of the operation.

C. A description of any maintenance or repair associated with established control measures that are recommended as a result of the inspection and a review of outstanding recommendations for maintenance or repair from previous inspection(s), i.e., whether recommended action has been taken, is yet to be performed or no longer appears to be required.

D. A summary of the observed implementation or status of actual control measures.

ii. For the inspections required by Condition 7.1.8(b) for the affected new coke conveyor system, pursuant to Permit 06070088:

A. The Permittee shall maintain a file, which shall be kept current, that contains the maximum operating capacity of the new coke conveyance system (tons/day).

B. 1. The Permittee shall keep inspection and maintenance log(s) or other records for the control measures associated with the new coke conveyance system, including enclosures and fabric filters.

2. These records shall include the following information for the inspections required by Condition 7.1.8(a) and (b):

I. Date and time the inspection was performed.

II. The observed condition of the control measures, including the presence of any visible emissions.

III. A description of any maintenance or repair associated with the control measures that are recommended as a result of the inspection and a review of outstanding recommendations for maintenance or repair from previous inspection(s), i.e., whether recommended action has been taken, is yet to be performed or no longer appears to be required.

f. In the operational logs or other records for the operation of the affected material handling operations for steelmaking, the Permittee shall include information confirming routine implementation of normal practices for unloading of materials into the receiving hopper and housekeeping practices for this hopper and information identifying departures from those practices, with description, explanation, and corrective actions taken.

g. The Permittee shall maintain records of the following for each incident when any affected material handling operations and the new coke conveyor system operate without control measures:

i. The date of the incident and identification of the operations that were involved.

ii. A description of the incident, including the control measures that were not present or implemented; the control measures that were present, if any; other control measures or mitigation measures that were

implemented, if any; and the magnitude of the PM emissions during the incident.

iii. The time at and means by which the incident was identified, e.g., scheduled inspection or observation by operating personnel.

iv. The length of time after the incident was identified that the operations continued to operate before control measures were in place or the operations were shutdown (to resume operation only after control measures were in place) and, if this time was more than one hour, an explanation why this time was not shorter, including a description of any mitigation measures that were implemented during the incident.

v. The estimated total duration of the incident, i.e., the total length of time that the operations ran without control measures and the estimated amount of coal handled during the incident.

vi. A discussion of the probable cause of the incident and any preventative measures taken.

vii. A discussion whether any applicable emission standards, as listed in Condition 7.1.3, may have been violated during the incident, with supporting explanation.

h. The Permittee shall maintain the following records for the new coke conveyor system and each other operation subject to limits on PM/PM_{10} emissions in Condition 7.1.6:

i. A file containing the emission factors used by the Permittee to determine emissions of each operation, with supporting documentation. These records shall be reviewed and updated by the Permittee as necessary to assure that the emission factors that it uses to determine emissions of the affected operations do not understate actual emissions. These records shall be prepared and copies sent to the Illinois EPA in accordance with Condition 5.9.6(c).

ii. Records for any periods of operation of such operations that are not otherwise addressed in the required records during which the established emission factor in Condition 7.1.9(f)(i) would understate actual emissions of such operation, with description of the period of operation and an estimate of the additional emissions during such period that would not be accounted for by the established factor, with supporting explanation and calculations.

iii. Records for the annual PM/PM_{10} emissions of each operation, based on operating data and appropriate emission factors for comparison to the limits in Conditions 7.1.6(b), with supporting documentation and calculations.

i. The Permittee shall keep records for all opacity measurements conducted in accordance with Method 9 that it conducts or that it orders to be conducted. For each occasion on which such measurements are made, these records shall include the identity of the observer, a description of the measurements that were made, the operating condition of the operations, the observed opacity, and copies of the raw data sheets for the measurements.

j. The Permittee shall keep copies of all tests performed on the affected material handling operations and new coke conveyor system.

7.1.10 Reporting Requirements

a. i. The Permittee shall submit quarterly and annual reports to the Illinois EPA in accordance with 35 IAC 212.316(g)(1) and (5) [35 IAC 212.316(g)].

ii. Pursuant to 35 IAC 212.324(g)(6), upon written request by the IEPA, a report shall be submitted to the IEPA for any period specified in the request stating the following: the dates during which any process emission unit was in operation when the air pollution control equipment was not in operation or was not operating properly, documentation of causes for pollution control equipment not operating or not operating properly, and a statement of what corrective actions were taken and what repairs were made.

iii. Pursuant to Permit 06070088 for the new coke conveyor system, the Permittee shall notify the Illinois EPA within 30 days of deviations from applicable emission standards or operating requirements that continue* for more than 24 hours.

* For this purpose, time shall be measured from the start of a particular event. The absence of a deviation for a short period shall not be considered to end the event if the deviation resumes. In such circumstances, the event shall be considered to continue until corrective actions are taken so that the deviation ceases or the Permittee takes the affected unit out of service for repairs.

b. i. Pursuant to Section 39.5(7)(f)(ii) of the Act, the Permittee shall promptly notify the Illinois EPA, Air

Compliance Section, within 30 days of deviations by the affected material handling operations and new coke conveyor system from applicable requirements as follows:

A. Requirements in Condition 7.1.3(b) through (f).

B. Requirements in Condition 7.1.5.

C. Requirements in Condition 7.1.6.

ii. All such deviations shall be summarized and reported as part of the semiannual monitoring report required by Condition 8.6.1.

iii. The Permittee shall notify the Illinois EPA, Air Compliance Section, of all other deviations from permit requirements as part of the semiannual monitoring reports required by Condition 8.6.1.

iv. All deviation reports described in Condition 7.1.11(b) above shall contain the following:

A. Date, time and duration of the deviation;

B. Description of the deviation;

C. Probable cause of the deviation; and

D. Any corrective actions or preventive measures taken.

7.1.11 Operational Flexibility/Anticipated Operating Scenarios

Operational flexibility is not set for the affected material handling operations and new coke conveyor system.

7.1.12 Compliance Procedures

Compliance with the emission standards in Condition 7.1.3 and the operational/emission limits in Condition 7.1.6 is addressed by the testing requirements of Condition 7.1.7, inspection requirements of Condition 7.1.8 and recordkeeping requirements of Condition 7.1.9.

7.1.13 State-Only Conditions

State-only conditions are not being established.

7.2 Coke Production

7.2.1 Description

Two coke oven batteries (45 ovens each), dual collecting main by-product coke oven batteries, referred to as batteries A and B, are utilized at this iron and steel mill. Each is capable of processing 454,000 tons/year of coal. Potential emissions from these batteries consist of particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, volatile organic materials, and HAPs.

Topside:

Emission points include leaks from coke oven charging, lids, off takes, soaking and emergency flares. Coal is charged to the ovens through four charging port lids, on each oven, utilizing sequential charging with steam aspiration to the collecting mains. Each oven has two off takes to the collecting mains that duct raw coke oven gas from the coking process to the by-products plant (see Section 7.3 of this permit). Soaking occurs after the coking process is completed, when an oven is dampered off from the collecting mains and its off takes' standpipes are opened before beginning pushing. Each battery also has an emergency by-pass on the collecting main (one on each main, two per battery). In the event of an emergency which would lead to excess pressure in a main, e.g., loss of suction from the by-product plant, the by-pass opens. The raw coke oven gas is then combusted in the associated emergency flare.

Doors:

Emissions consist of leaks from coke oven doors. Each oven has two doors, with one on its push side and one on its coke side.

Pushing:

Once the coking cycle in an oven has been completed, the push and coke side doors are removed, respectively, by the pushing machine and coke-side door machines. A ram on the pushing machine pushes the coke out through a guide on the door machine. The coke falls through the guide, which is covered by a hood on the machine, and into the quench box. The emissions from oven pushing are controlled by the pushing system. This mobile control system consists of a venturi scrubber, mist eliminator and exhaust fan. The Permittee currently has two mobile scrubber cars for pushing (PCS cars #3 and #4). The quench box and car travel with this system to the coke quenching operation.

Coke Quenching:

In this operation, loads of hot coke from the ovens are quenched with water. There are two locations where quenching normally takes place. The primary is the West Quench Tower. This tower is equipped with a baffle system. The east quench station,

which is utilized as a backup for the West Tower, does not currently have a quench tower, however, the Permittee is currently engaged in a project to upgrade the quenching operations, adding a quench tower to the East Quench Station and replacing the conventional Quench Tower at the West Quench Station with a low emission quench tower (Construction Permit 08060026).

Underfiring:

Coke oven gas (COG) is combusted to generate the heat required to convert coal to coke. This COG would be treated by both by-products plant and, except during maintenance and outage, by the COG desulfurization system. Natural gas may also be added through the blending station in order to stabilize the heat content of the COG. Emissions from this unit occur at the main stacks of each battery and are mainly the by-products of combustion, including particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, and volatile organic materials.

Note: This narrative description is for informational purposes only and is not enforceable.

7.2.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Date Constructed	Emission Control Equipment
Coke Oven Batteries "A" and "B"	Coke Oven Battery "A"	Battery "A" was rebuilt between 1979 and 1980	Emergency Bypass Flares
	Coke Oven Battery "B"	Battery "B" was rebuilt between 1981 and 1982	Emergency Bypass Flares
	2 Larry Cars		None
	2 Pushing/Quench Cars		Mobile Venturi Scrubber (PCS Cars #3 & #4)
	East Quench Station (backup)		Tower and Baffles (planned)
	West Quench Station		Tower and Baffles
	Coke Oven Underfiring (coke oven combustion stacks)		None

7.2.3 Applicable Provisions

a. The "affected coke oven operations" for the purpose of these unit-specific conditions, are the emission units and activities described in Conditions 7.2.1 and 7.2.2.

b. The affected coke oven operations are subject to 35 IAC 212.443. Certain provisions of this regulation are discussed further in this subsection.

c. i. The following affected coke oven operations are subject to 40 CFR Part 63, Subpart L Coke Oven Batteries: charging, doors, lids, off takes, collecting mains and bleeder stacks. The Permittee is complying with the so-called LAER track under this NESHAP, as provided for by 40 CFR 63.304.

ii. For affected coke oven operations, the Permittee shall comply with applicable provisions of the NESHAP, 40 CFR 63 Subpart A.

d. i. The following affected coke oven operations are subject to 40 CFR Part 63, Subpart CCCCC: pushing, soaking, quenching and battery underfiring stacks.

ii. For affected operations at the coke oven battery, the Permittee shall comply with applicable provisions of the NESHAP, 40 CFR 63 Subpart A as specified in Table 1 in 40 CFR 63 Subpart CCCCC.

7.2.3-1 Applicable Standards: Coke Oven Charging

a. 35 IAC 212.443(b)(1)(A)

No person shall cause or allow the emission of visible particulate matter from any coke oven charging operation, from the introduction of coal into the first charge port, as indicated by the first mechanical movement of the coal feeding mechanism on the larry car, to the replacement of the final charge port lid for more than a total of 125 seconds over 5 consecutive charges; provided however that 1 charge out of any 20 consecutive charges may be deemed an uncountable charge at the option of the operator.

Compliance with this limit shall be determined in accordance with the applicable procedures in 35 IAC 212.443(b)(1)(B) and Condition 7.2.12.

b. 40 CFR 63.304(b)(2)(iv)

Emissions to the atmosphere from coke oven charging shall not exceed 12 seconds of visible emissions per charge, as determined by the procedures in 40 CFR 63.309(d)(2).

c. Battery B

The aggregate of visible emissions from the charging of coke ovens at Battery B shall not exceed a total 55 seconds during any 5 consecutive charges [T1].

Note: This limit is the determination of LAER for charging for Battery B made in Construction Permit C808048.

7.2.3-2 Applicable Standards: Leaks from Doors

a. 35 IAC 212.443(d)

i. No person shall cause or allow visible emissions from more than 10 percent of all coke oven doors at any time. Compliance shall be determined by a one pass observation of all coke oven doors on any one battery.

ii. No person shall cause or allow the operation of a coke oven unless there is on the plant premises at all times an adequate inventory of spare coke oven doors and seals and unless there is a readily available coke oven door repair facility.

b. Battery B

At no time shall there be any visible emissions from more than 5 percent of the door areas on Battery B [T1].

Note: This limit is the determination of LAER for door leaks for Battery B was established in Construction Permit C808048.

c. 40 CFR 63.304(b)(3)(ii)

3.3 percent leaking coke oven doors for each by-product coke oven battery not subject to the emission limitation 40 CFR 63.304(b)(3)(i), as determined by the procedures in 40 CFR 63.309(d)(1).

7.2.3-3 Applicable Standards: Leaks from Lids

a. 35 IAC 212.443(e)

No person shall cause or allow visible emissions from more than 5 percent of all coke oven lids at any time. Compliance shall be determined by a one pass observation of all coke oven lids.

b. Battery B

There shall be no visible emissions from more than 1 percent of the charging ports or lids [T1].

Note: This limit is the determination of LAER for lid leaks for Battery B made in Construction Permit C808048.

c. 40 CFR 63.304(b)(2)(ii)

0.4 percent leaking topside port lids, as determined by the procedures in 40 CFR 63.309(d)(1).

7.2.3-4 Applicable Standards: Leaks from Off Takes

a. 35 IAC 212.443(f)

No person shall cause or allow visible emissions from more than 10 percent of all coke oven off take piping at any time. Compliance shall be determined by a one pass observation of all coke oven off take piping.

b. Battery B

There shall be no visible emissions from more than 4 percent of the off take piping on the coke ovens on Battery B [T1].

Note: This limit is the determination of LAER for off take leaks for Battery B made in Construction Permit C808048.

c. 40 CFR 63.304(b)(2)(iii)

2.5 percent leaking off take system(s), as determined by the procedures in 40 CFR 63.309(d)(1).

7.2.3-5 Applicable Standards: Coke Oven Pushing

a. 35 IAC 212.443(c)(1)(A)

Emissions of uncaptured particulate matter from pushing operations shall not exceed an average of 20 percent opacity for 4 consecutive pushes considering the highest average of six consecutive readings in each push.

Compliance with this limit shall be determined in accordance with the procedures in 35 IAC 212.443(c)(1)(B) and Condition 7.2.12.

b. 35 IAC 212.443(c)(2)

i. The particulate emissions from control equipment used to control emissions during pushing operations shall not exceed 0.040 pounds per ton of coke pushed. Compliance shall be determined in accordance with the procedures set forth in 40 CFR Part 60, Appendix A, Methods 1-5, incorporated by reference in Section 212.113. Compliance shall be based on an arithmetic average of three runs (stack tests) and the

calculations shall be based on the duration of a push as defined in 35 IAC 212.443(c)(1)(A).

ii. The opacity of emissions from control equipment used to control emissions during pushing operations shall not exceed 20%. For a push of less than six minutes duration, the actual number of 15-second readings taken shall be averaged. Compliance shall be determined in accordance with 40 CFR Part 60, Appendix A, Method 9, incorporated by reference in 35 IAC 212.113, Section 2.5 of 40 CFR Part 60, Appendix A, Method 9, incorporated by reference in 35 IAC 212.113, for data reduction shall not be used for pushes of less than six minutes duration [35 IAC 212.443(c)(2)(B)].

c. 40 CFR 63.7290(a)(4)

Particulate matter emissions to the atmosphere from the mobile scrubber car for pushing which captures emissions during travel shall not exceed 0.04 lb/ton of coke.

d. Battery B

Pushing emissions from Battery B shall be captured and cleaned by a single-spot, coke guide evacuated, enclosed quench car/scrubber car system which meets the following limitations [T1]:

i. The gas cleaning device shall be operated to meet 0.04 pounds of particulate matter per ton of coke pushed during the pushing operation.

ii. Visible emissions from the gas cleaning device outlet and uncaptured fugitive emissions shall not exceed 20 percent opacity.

Note: These limits are the determination of LAER for pushing emissions from Battery B made in Construction Permit C808048.

7.2.3-6 Applicable Standards: Coke Quenching

a. i. 40 CFR 63.7295(a)(1)(i)

For the quenching of hot coke, the Permittee must meet the following requirements of 40 CFR 63.7295(a)(1)(i):

The concentration of total dissolved solids (TDS) in the water used for quenching must not exceed 1,100 milligrams per liter (mg/L).

ii. 40 CFR 63.7295(a)(2)

The Permittee must use acceptable makeup water, as defined in 40 CFR 63.7352, as makeup water for quenching.

iii. 40 CFR 63.7295(b)

For each quench tower at a coke oven battery, the Permittee must meet each of the following requirements:

A. Pursuant to 40 CFR 63.7295(b)(1), each tower is equipped with baffles such that no more than 5 percent of the cross sectional area of the tower may be uncovered or open to the sky;

B. Pursuant to 40 CFR 63.7295(b)(2), baffles in each quench tower shall be washed once each day that the tower is used to quench coke, except as specified below:

1. Baffles in a quench tower are not required to be washed if the highest measured ambient temperature remains less than 30 degrees Fahrenheit throughout that day (24-hour period). If the measured ambient temperature rises to 30 degrees Fahrenheit or more during the day, the Permittee shall resume daily washing.

2. The Permittee shall continuously record the ambient temperature on days that the baffles were not washed.

C. Pursuant to 40 CFR 63.7295(b)(3) and (4), the Permittee shall comply with inspection and repair provisions (see Condition 7.2.8-3).

b. 35 IAC 212.443(h)(1)

All coke oven quench towers shall be equipped with grit arrestors or equipment of comparable effectiveness. Baffles shall cover 95 percent or more of the cross sectional area of the exhaust vent or stack and must be maintained. Quench water shall not include untreated coke by-product plant effluent. All water placed on the coke being quenched shall be quench water.

c. 35 IAC 212.443(h)(2)

Total dissolved solids concentrations in the quench water shall not exceed a weekly average of 1200 mg/L.

7.2.3-7 Applicable Standards: Combustion (Battery) Stack

a. 35 IAC 212.443(g)

i. No person shall cause or allow the emissions of particulate matter from a coke oven combustion stack to exceed 110 mg/dscm (0.05 gr/dscf); and

ii. No person shall cause or allow the emission of particulate matter from a coke oven combustion stack to exceed 30% opacity. Compliance shall be determined in accordance with 40 CFR Part 60, Appendix A, Method 9, incorporated by reference in 35 IAC 212.113. However, the opacity limit shall not apply to a coke oven combustion stack when a leak between any coke oven and the oven's vertical or crossover flues is being repaired, after pushing coke from the oven is completed, but before resumption of charging. The exemption from the opacity limit shall not exceed three (3) hours per oven repaired. The owner or operator shall keep written records identifying the oven repaired, and the date, time, and duration of all repair periods. These records shall be subject to the requirements of 35 IAC 212.324(g)(4) and (g)(5).

b. 40 CFR 63.7296

The Permittee must not discharge to the atmosphere any emissions from any battery stack at an existing by-product coke oven battery that exhibits opacity greater than the following applicable limits:

i. Daily average of 15 percent opacity for a battery on a normal coking cycle.

ii. Daily average of 20 percent opacity for a battery on batterywide extended coking.

c. Battery B

Pursuant to Construction Permit 82060043, non-sulfate particulate matter emissions from the battery stack serving Battery B shall not exceed 0.03 gr/dscf [T1].

7.2.3-8 Applicable Standards: Bypass/Bleeder Stack

a. i. Pursuant to 40 CFR 63.307(a)(1), the Permittee shall operate and properly maintain a bypass/bleeder stack flare system that is capable of controlling 120 percent of the normal gas flow generated by the affected battery.

ii. Coke oven emissions shall not be vented to the atmosphere through bypass/bleeder stacks, except

through the flare system or an alternative control device as described in 40 CFR 63.307(d) [40 CFR 63.307(a)(2)].

iii. Each flare installed pursuant to 40 CFR 63.307 shall meet the applicable requirements specified by 40 CFR 63.307(b) with compliance determined as specified by 40 CFR 63.309(h).

b. Pursuant to 40 CFR 63.307(c), the flare shall be operated with no visible emissions, as determined by the methods specified in 40 CFR 63.309(h)(1), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

7.2.4 Non-Applicability of Regulations of Concern

a. The emission limitations of 35 IAC 212.324 are not applicable to any emission unit subject to a specific emissions standard or limitation contained in 35 IAC Part 212 Subpart R, Primary and Fabricated Metal Products and Machinery Manufacture, pursuant to 35 IAC 212.324 (a)(3).

b. The affected coke oven operations are not fuel combustion emission units as defined in 35 IAC 211.2470 and therefore are not subject to the standards for fuel combustion emission units in 35 IAC Parts 212, 214, 216 and 217.

c. This permit is issued based on the affected coke oven operations not being subject to the applicable requirements of 35 IAC 219.301 because there is 85 percent reduction of uncontrolled organic material that would otherwise be emitted into atmosphere, pursuant to 35 IAC 219.302.

7.2.5-1 Work Practices: Soaking Plan (40 CFR 63.7294)

Pursuant to 40 CFR 63.7294(a), the Permittee shall operate the coke ovens pursuant to a written work practice plan for soaking, which includes the measures specified by 40 CFR 63.7294(a), including, if soaking emissions are caused by leaks from the collecting main, the Permittee shall take corrective actions to eliminate soaking emissions in accordance with the actions identified in the soaking plan. If soaking emissions are not caused by leaks, the Permittee must determine whether the soaking emissions are due to incomplete coking. If incomplete coking is the cause of the soaking emissions, the Permittee must put the oven back on the collecting main until it is completely coked or the Permittee must ignite the standpipe emissions as specified by 40 CFR 63.7294(a)(4) and (5).

7.2.5-2 Work Practice Plan (40 CFR 63.306)

a. Pursuant to 40 CFR 63.306(c), for affected units subject to the NESHAP, 40 CFR 63 Subpart L, the Permittee shall implement a written emission control Work Practice Plan for each affected coke oven battery designed to achieve

compliance with visible emission limitations for coke oven doors, topside port lids, off take systems, and charging operations.

b. Pursuant to 40 CFR 63.306(a)(1) and (b), the Permittee shall organize the work practice plan to indicate clearly which parts of the plan pertain to each emission point subject to visible emission standards under 40 CFR Subpart L. Each of the following provisions, at a minimum, shall be addressed in the plan in sufficient detail and with sufficient specificity to allow USEPA and the Illinois EPA to evaluate the plan for completeness and enforceability:

i. An initial and refresher training program for all coke plant operating personnel with responsibilities that impact emissions, including contractors, in job requirements related to emission control and the requirements of 40 CFR Subpart L, including work practice requirements, that includes all the elements specified by 40 CFR 63.306(b)(1). Contractors with responsibilities that impact emission control may be trained by the Permittee or by qualified contractor personnel; however, the Permittee shall ensure that the contractor training program complies with the requirements of 40 CFR 63.306(b)(1).

ii. Procedures for controlling emissions from coke oven doors on by-product coke oven batteries, including the elements specified by 40 CFR 63.306(b)(2).

iii. Procedures for controlling emissions from charging operations on by-product coke oven batteries, including the elements specified by 40 CFR 63.306(b)(3).

iv. Procedures for controlling emissions from topside port lids on by-product coke oven batteries, including the elements specified by 40 CFR 63.306(b)(4).

v. Procedures for controlling emissions from off take system(s) on by-product coke oven batteries, including the elements specified by 40 CFR 63.306(b)(5).

vi. Procedures for each emission point subject to visible emission limitations under 40 CFR 63 Subpart L for maintaining a daily record of the performance of plan requirements pertaining to the daily operations of the affected coke oven operations as defined in Condition 7.2.3(c) and its emission control equipment, including the elements specified by 40 CFR 63.306(b)(7).

vii. Any additional work practices or requirements specified by the USEPA or Illinois EPA pursuant to 40 CFR 63.306(d).

c. Pursuant to 40 CFR 63.306(c) the Permittee shall implement the provisions of the work practice plan pertaining to a particular emission point:

i. Following the second independent exceedance of the visible emission limitation for the emission point in any consecutive 6-month period, by no later than 3 days after receipt of written notification of the second such exceedance from the certified observer. For this purpose, the second exceedance is "independent" if the criteria of 40 CFR 63.306(c)(1)(i)(A), (B) or (C) are met.

ii. And continue to implement such plan provisions until the visible emission limitation for the emission point is achieved for 90 consecutive days. After the visible emission limitation for a particular emission point is achieved for 90 consecutive days, any exceedances prior to the beginning of the 90 days are not included in making the above determination of exceedances.

d. Revisions to the work practice plan shall be done in accordance with 40 CFR 63.306(d) and (a)(2).

e. The Work Practice Plan, as submitted by the Permittee on November 12, 1993, (which contains various training and standard operating procedures for the A & B coke oven batteries), is incorporated herein by reference. The document constitutes the formal work practice plan required by 40 CFR 306(a) for each coke oven battery, addressing work practices for achieving compliance with the visible emissions limitations of Subpart L.

Any future revision to the aforementioned plan made by the Permittee during the permit term is automatically incorporated by reference provided that said revision is not expressly disapproved, in writing, by the Illinois EPA within 30 days of receipt of said revision. In the event that the Illinois EPA notifies the Permittee of a deficiency with any revision to the plan, the Permittee shall be required to revise and resubmit the plan within 30 days of receipt of notification to address the deficiency [Section 39.5(7)(a) of the Act].

7.2.5-3 NESHAP Provisions for Startup, Shutdown and Malfunction

a. Pursuant to 40 CFR 63.7310(a) and (c), for affected coke oven operations subject to 40 CFR 63 Subpart CCCCC:

i. The Permittee shall comply with the emission limitations, work practice standards, and operating and maintenance requirements of 40 CFR 63 Subpart CCCCC, at all times except periods of startup, shutdown, and malfunction as defined at 40 CFR 63.2.

ii. The Permittee shall develop and implement a written startup, shutdown and malfunction plan according to the provisions in 40 CFR 63.6(e)(3).

b. Pursuant to 40 CFR 63.310, for affected coke oven operations subject to 40 CFR 63 Subpart L:

i. At all times, including periods of startup, shutdown, and malfunction, the Permittee shall operate and maintain the affected coke oven operations, and associated pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions to the levels required by standards under 40 CFR Subpart L. Failure to adhere to the requirement of 40 CFR 63.310 shall not constitute a separate violation if a violation of an applicable performance or work practice standard has also occurred [40 CFR 63.310(a)].

ii. The Permittee shall develop and implement according to 40 CFR 63.310(c), a written startup, shutdown, and malfunction plan that describes procedures for operating the affected units, including associated air pollution control equipment, during a period of a startup, shutdown, or malfunction in a manner consistent with good air pollution control practices for minimizing emissions, and procedures for correcting malfunctioning process and air pollution control equipment as quickly as practicable [40 CFR 63.310(b)].

iii. Pursuant to 40 CFR 63.310(c), during a period of startup, shutdown, or malfunction the Permittee shall operate the battery (including associated air pollution control equipment) in accordance with the procedure specified in the startup, shutdown, and malfunction plan; and malfunctions shall be corrected as soon as practicable after their occurrence, in accordance with the plan.

iv. To satisfy the requirement for a startup, shutdown, and malfunction plan, the Permittee may use the standard operating procedures manual for the battery, provided the manual meets all the requirements of 40 CFR 63.310 and is made available for inspection at reasonable times when requested by the Administrator (USEPA) or Illinois EPA, as provided by 40 CFR 63.310(g).

v. The USEPA or Illinois EPA may require reasonable revisions to a startup, shutdown, and malfunction plan as provided by 40 CFR 63.310(h).

vi. Pursuant to 40 CR 63.310((i), if the Permittee demonstrates to the satisfaction of the Administrator (USEPA and Illinois EPA) that a startup, shutdown, or malfunction has occurred, then an observation occurring during such startup, shutdown, or malfunction shall not:

A. Constitute a violation of relevant requirements of 40 CFR 63 Subpart L;

B. Be used in any compliance determination under 40 CFR 63.309; or

C. Be considered for purposes of 40 CFR 63.306 (the work practice plan), until the Administrator (USEPA and Illinois EPA) has resolved the claim that a startup, shutdown, or malfunction has occurred, as further provided by 40 CFR 63.310(i)(3).

vii. The Permittee shall maintain all records related to startup, shutdown and malfunction, including internal reports which form the basis of each malfunction notification under 40 CFR 63.310(d) as required by 40 CFR 63.310(f).

7.2.5-4 Startup Authorization Pursuant to State Rule

Pursuant to 35 IAC 201.149 and Part 201, Subpart I, subject to the following terms and conditions, for the affected coke ovens, the Permittee is authorized to violate the applicable standards in 35 IAC 212.443 during startup. For this purpose a start-up is the resumption of normal production following the period when the battery has been idled.

Note: This authorization is provided because the Permittee has applied for such authorization in its CAAPP application, generally describing the efforts that will be used "…to minimize startup emissions, duration of individual starts, and frequency of startups".

a. This authorization does not relieve the Permittee from the continuing obligation to demonstrate that all reasonable efforts are made to minimize startup emissions, duration of individual startups and frequency of startups.

b. The Permittee shall conduct startup of the affected coke oven operations in accordance with the manufacturer's written instructions or other written procedures prepared by the Permittee and maintained at the source (see

Condition 7.2.9(g)(i)), that are specifically developed to minimize emissions from the startup.

c. The Permittee shall fulfill applicable recordkeeping of Condition 7.2.9(g).

d. The Permittee shall fulfill applicable reporting of Condition 5.10.5-1.

e. As provided by 35 IAC 201.265, an authorization in a permit for excess emissions during startup does not shield a Permittee from enforcement for any violation of applicable emission standard(s) that occurs during startup and only constitutes a prima facie defense to such an enforcement action provided that the Permittee has fully complied with all terms and conditions connected with such authorization.

7.2.5-5 Malfunction and Breakdown Authorization Pursuant to State Rule

a. Pursuant to 35 IAC 201.149 and Part 201, Subpart I, subject to the following terms and conditions, the Permittee is authorized to continue operation of the affected coke oven batteries in excess of the applicable state standards in 35 IAC 212.443 in the event of a malfunction or breakdown.

Note: This authorization is provided because the Permittee applied for such authorization in its CAAPP application, generally explaining why such continued operation would be required to prevent injury to personnel or severe damage to equipment, and describing the measures that will be taken to minimize emissions from any malfunctions and breakdowns.

i. This authorization only allows such continued operation as necessary to prevent injury to personnel or severe damage to equipment and does not extend to continued operation solely for the economic benefit of the Permittee.

ii. Upon occurrence of excess emissions due to malfunction or breakdown, the Permittee shall repair the responsible affected coke oven operations or other responsible equipment and/or re-establish the applicable control practices (e.g., the rail system for quench car).

iii. The Permittee shall fulfill the applicable recordkeeping and reporting requirements of Conditions 7.2.9(h) and Condition 5.10.5-2, respectively. For these purposes, time shall be measured from the start of a particular incident. The absence of excess emissions for a short period shall not be considered to end the incident if excess emissions resume.

iv. Following notification to the Illinois EPA (see Condition 5.10.5-2(a)(i))of a malfunction or breakdown with excess emissions, the Permittee shall comply with all reasonable directives of the Illinois EPA with respect to such incident.

v. This authorization does not relieve the Permittee from the continuing obligation to minimize excess emissions during malfunction or breakdown. As provided by 35 IAC 201.265, an authorization in a permit for continued operation with excess emissions during malfunction and breakdown does not shield the Permittee from enforcement for any such violation and only constitutes a prima facie defense to such an enforcement action provided that the Permittee has fully complied with all terms and conditions connected with such authorization.

b. During the period when only one quench station is available (i.e., the other quench station is not operable because of construction work on a new quench tower) or there is a malfunction or breakdown preventing hot coke from being moved to a tower-equipped quench station (e.g., rail line malfunction), the Permittee is authorized to continue operation of the coke ovens with emergency quenching, i.e., quenching without a quench tower or at a quench station that is experiencing a malfunction or breakdown (see Condition 7.2.5-5).

7.2.6 Production and Emission Limitations

a. i. The amount of coal charged to the affected Battery "B" shall not exceed 454,000 tons per year [Construction Permit C808048].

b. i. Emissions of PM from the mobile scrubber cars for pushing shall not exceed 4.2 lb/hr and 18.3 t/yr [T1].

Compliance with annual limits shall be determined from a running total of 12 months of data [Construction Permit 88070071].

ii. Spare cars, parts inventories and maintenance practices shall be maintained and implemented by the Permittee for the pushing operations (quench cars and mobile scrubbers) consistent with good air pollution control practices [Permit 88070071].

c. i. Supplementary natural gas usage for the coke ovens shall not exceed 20 million scf/month and 123 million scf/yr [T1].

ii. Emissions attributable to the combustion of natural gas for the underfiring of the batteries shall not exceed the following limits. Compliance with the

annual limits shall be determined from a running total of 12 months of data [T1]:

	Emissions	
Pollutant	(Tons/Month)	(Tons/Year)
NO_x	2.80	17.22
CO	0.84	5.17
PM	0.12	0.73
PM_{10}	0.11	0.62
VOM	0.06	0.34
SO_2	0.01	0.04

iii. The above limitations were established in the Permit 04110018.

d. i. Once shakedown of the new quench tower on the West Quench Station has been completed, the Permittee shall use the West Quench Station preferentially. For this purpose, on an annual basis*, excluding periods when the West Quench Station cannot be used due to malfunction or breakdown, the East Quench Station shall not quench more than: 5 percent of the total number of quenches or 15,000 tons of coke, whichever is greater, not to exceed 30,000 tons of coke per year.

* This limit shall apply for the 12 month period from July 1 of one year through June 30 of the following year. This limit shall also apply for the initial 12 months following shakedown of the West Quench Station with new quench tower.

ii. Shakedown of each affected quench tower shall be completed within 180 days of the initial quench with each tower.

iii. The above limitations were established in the Permit 08060026.

7.2.7-1 Emission Testing for Coke Oven Pushing

a. Testing requirements established by 40 CFR Part 63 Subpart CCCCC:

i. Pursuant to 40 CFR 63.7321, for each control device subject to an emission limit for particulate matter in 40 CFR 63.7290(a), the Permittee must conduct performance tests no less frequently than twice (at mid-term and renewal) during each term of the CAAPP permit (i.e., every 30 months).

ii. The Permittee must conduct each performance test according to the following requirements in 40 CFR 63.7322.

A. To determine compliance with a process-weighted mass rate of particulate matter (lb/ton of coke) from a control device applied to pushing emissions where a cokeside shed is not used, follow these test methods and procedures to determine the concentration of particulate matter according to the following test methods in Appendix A to 40 CFR Part 60:

1. Method 1 to select sampling port locations and the number of traverse points. Sampling sites must be located at the outlet of the control device and prior to any releases to the atmosphere.

2. Method 2, 2F, or 2G to determine the volumetric flow rate of the stack gas.

3. Method 3, 3A, or 3B to determine the dry molecular weight of the stack gas.

4. Method 4 to determine the moisture content of the stack gas.

5. Method 5 or 5D, as applicable, to determine the concentration of front half particulate matter in the stack gas.

B. During each particulate matter test run, sample only during periods of actual pushing when the capture system fan and control device are engaged. Collect a minimum sample volume of 30 dry standard cubic feet of gas during each test run. Three valid test runs are needed to comprise a performance test. Each run must start at the beginning of a push and finish at the end of a push (*i.e.*, sample for an integral number of pushes).

C. Determine the total combined weight in tons of coke pushed during the duration of each test run according to the procedures in the Permittee's source test plan for calculating coke yield from the quantity of coal charged to an individual oven.

D. Compute the process-weighted mass emissions (E_p) for each test run using the following equation:

$$E_p = \frac{C \times Q \times T}{P \times K} \qquad \text{(Eq. 1)}$$

Where:

E_p = Process weighted mass emissions of particulate matter, lb/ton;

C = Concentration of particulate matter, gr/dscf;

Q = Volumetric flow rate of stack gas, dscf/hr;

T = Total time during a run that a sample is withdrawn from the stack during pushing, hr;

P = Total amount of coke pushed during the test run, tons; and

K = Conversion factor, 7,000 gr/lb.

b. Testing requirements to address 35 IAC 212.443(c)(2)

If the PM emissions measured during the emissions testing conducted pursuant to Condition 7.2.7-1(a) are more than 0.036 lb/ton, the Permittee shall conduct a follow-up test between 12 and 18 months after such test, unless subsequent emission testing conducted in the 12 month period following such test shows PM emissions are no more than 0.030 lb/ton.

7.2.7-2 Testing Requirements for Coke Quenching

a. Requirements of 40 CFR Part 63 Subpart CCCCC

i. Pursuant to 40 CFR 63.7333(f), the Permittee shall sample and analyze quench water for total dissolved solids on at least a weekly basis in accordance with the procedures specified by 40 CFR 63.7325(a).

ii. If the Permittee elects to comply with the TDS limit for quench water in 40 CFR 63.7295(a)(1)(i), the Permittee must conduct each performance test that applies to the affected quenching operations according to the following conditions in 40 CFR 63.7325(a)(1) and (2):

A. Take the quench water sample from a location that provides a representative sample of the quench water as applied to the coke (e.g., from the header that feeds water to the quench tower reservoirs). Conduct sampling under normal and representative operating conditions.

B. Determine the TDS concentration of the sample using Method 160.1 in 40 CFR part 136.3 (see residue-filterable"), except that you must dry the total filterable residue at 103 to 105°C instead of 180°C.

b. Requirements of 35 IAC 212.443(h)

i. Pursuant to 35 IAC 212.443(h)(3), the quench water shall be sampled for total dissolved solids concentrations in accordance with the methods specified in Standard Methods for the Examination of Water and Wastewater, Section 209C, "Total Filterable Residue Dried at 103-105°C" 15th Edition, 1980, incorporated by reference in 35 IAC 212.113. Analyses shall be performed on grab samples of the quench water as applied to the coke in accordance with the sampling schedule in Condition 7.2.12(c).

ii. If the quench station is not used during any given calendar week, the grab samples for that quench station need not be analyzed.

c. Testing requirements for West Quench Station from Permit 08060026

Within two years after initial startup of the West Quench Station with low emission quench tower, the Permittee shall have emission test(s) conducted for this quench station at its expense as follows:

i. The emissions test(s) shall be designed to measure the PM, PM_{10}, and $PM_{2.5}$ emission rates (lb/ton coke) from the quench tower under conditions that are representative of the maximum emissions as the station is normally operated.

ii. The Permittee shall install any facilities necessary to accommodate this emissions testing.

iii. The following methods and procedures shall be used for testing emissions of PM unless other method(s) are approved by the Illinois EPA as part of its review of the test plan.

A. The following USEPA Test Methods:

Refer to 40 CFR 60, Appendix A for USEPA test methods and www.epa.gov/ttn/emc/prelim.html for other test methods.

Location of Sample Points	USEPA Method 1
Gas Flow and Velocity	USEPA Method 2
Flue Gas Weight	USEPA Method 3
Moisture	USEPA Method 4
PM	USEPA Method 5

B. Testing for emissions of filterable and condensable PM_{10} shall be conducted using an appropriate Test Method developed by USEPA, e.g., Method 201/201A or Other Test Method (OTM) 27 and Method 202 or OTM 28, or a Reference Method proposed by USEPA, subject to review by the Illinois EPA as part of the review of the test plan.

C. Testing for emissions of filterable $PM_{2.5}$ shall be conducted using an applicable Reference Method, as adopted by USEPA in 40 CFR Part 51, Appendix M, or in 40 CFR Part 60, Appendix A. If USEPA has not adopted a Reference Method for testing of filterable $PM_{2.5}$ when testing must be performed, testing for filterable $PM_{2.5}$ shall be conducted using an appropriate Test Method developed by USEPA, e.g., OTM 27, or a Reference Method proposed by USEPA, subject to review by the Illinois EPA as part of the review of the test plan.

iv. For this emission testing, test notification and reporting shall be done by the Permittee in accordance with Conditions 8.6.2 and 8.6.3 of this permit.

7.2.7-3 Compliance Demonstrations and Emission Testing for Coke Oven Underfiring (combustion stacks)

a. For compliance demonstration with opacity limits, the Permittee must conduct each performance test that applies to the affected operations according to the following requirements in 40 CFR 63.7324(b):

To determine compliance with the daily average opacity limit for stacks of 15 percent for a by-product coke oven battery on a normal coking cycle or 20 percent for a by-product coke oven battery on batterywide extended coking, follow the test methods and procedures outlined below:

i. Using the continuous opacity monitoring system (COMS) required in 40 CFR 63.7330(e), measure and record the

opacity of emissions from each battery stack for a 24-hour period.

ii. Reduce the monitoring data to hourly averages as specified in 40 CFR 63.8(g)(2).

iii. Compute and record the 24-hour (daily) average of the COMS data.

b. Pursuant to Sections 39.5(7)(d) and (p) of the Act, the Permittee shall conduct emission tests for each coke oven combustion stack under conditions that are representative of maximum emissions as follows:

i. Testing for PM emissions (filterable PM from Battery A and filterable and filterable non-sulfate PM from Battery B) shall be conducted as follows:

A. Initial testing shall be conducted within 24 months of the effective date of this permit condition.

B. Thereafter, emission testing shall be repeated in 30 months, unless the PM emission rate measured from both stacks during the previous testing is less than 0.040 gr/dscf for filterable PM and less than 0.024 gr/dscf for filterable non-sulfate PM from the combustion stack on Battery B, in which case testing shall be repeated in 60 months.

C. Testing shall also be conducted for combustion stack(s) upon written request from the Illinois EPA as specified in the request. This testing shall be completed within 90 days of the date of the request or such later date agreed to by the Illinois EPA.

ii. In conjunction with the initial testing for PM emissions required by Condition 7.2.7-3(b)(i)(A), the Permittee shall also test for CO and NO_x from one of the coke oven combustion stacks, as selected by the Illinois EPA.

iii. The following USEPA test methods shall be used for testing of emissions, unless another USEPA test method is approved by the Illinois EPA. Refer to 40 CFR 51, Appendix M, and 40 CFR 60, Appendix A, for test methods.

Location of Sample Points	Method 1
Gas Flow and Velocity	Method 2
Flue Gas Weight	Method 3
Moisture	Method 4

PM (filterable)	Method 5
PM (non-sulfate filterable)	Method 5F
CO	Method 10
NO_x	Method 7 or 7E

iv. For this emission testing, test notification and reporting shall be done by the Permittee in accordance with Conditions 8.6.2 and 8.6.3 of this permit.

v. With the report for emission testing, the Permittee shall also provide a summary of the opacity data monitored during the period of testing (6 minute averages and daily average), the sulfur content of COG being combusted during the period of testing, as measured by the monitoring system(s) for COG, the PM content of COG combusted during the period of testing, and data for the firing rate of the battery during testing (mmBtu or SCF of COG and natural gas per hour) for each test run, with supporting calculations.

c. Testing conditions above are established pursuant to Sections 39.5(7)(d) and (p) of the Act.

7.2.8-1 Monitoring Requirements for Charging, Doors, Lids and Off Takes

a. i. Pursuant to 40 CFR 63.309(a), daily performance tests shall be conducted by a certified observer each day, 7 days per week for the affected battery, as specified by 40 CFR 63.309, the results of which shall be used in accordance with procedures specified in 40 CFR 63 Subpart L to determine compliance with each of the applicable visible emission limitations for coke oven doors, topside port lids, off take systems, and charging operations in 40 CFR 63 Subpart L.

ii. The Permittee shall enter into a contract providing for the inspections and performance tests required under the NESHAP, 40 CFR 63 Subpart L, to be performed by a Method 303 certified observer. The inspections and performance tests will be conducted at the expense of the Permittee, during the period that the USEPA is the implementing agency [40 CFR 63.309(a)(5)(ii)].

A. The certified observer shall conduct daily performance tests according to the requirements specified in 40 CFR 63.309(c).

B. Pursuant to 40 CFR 63.309(c)(3), upon request of the certified observer the Permittee shall demonstrate pursuant to Reference Method 303 the accuracy of the pressure measurement device

for the collecting mains and shall not adjust the pressure to a level below the range of normal operation during or prior to the inspection.

C. In no case shall the owner or operator knowingly block a coke oven door, or any portion of a door for the purpose of concealing emissions or preventing observations by the certified observer, as prohibited by 40 CFR 63.309(c)(6).

D. 1. Pursuant to 40 CFR 63.309(e), the certified observer shall make available to the implementing agency, as well as to the Permittee, a copy of the daily inspection results by the end of the day and shall make available the calculated rolling average for each emission point to the Permittee as soon as practicable following each performance test. The information provided by the certified observer is not a compliance determination. For the purposes of notifying the owner or operator of the results obtained by a certified observer, the person does not have to be certified.

2. Pursuant to 40 CFR 63.306(d)(3), if the certified observer calculates that a second exceedance (or if applicable, a second independent exceedance) has occurred, the certified observer shall notify the Permittee. No later than 10 days after receipt of such notification, the Permittee shall notify the administrator (USEPA) and Illinois EPA of any finding of whether work practices are related to the cause or solution of the problem.

Note: Pursuant to 40 CFR 63.306(d)(6), the reviewing authority (USEPA) may disapprove the submitted finding if it determines that a revised work practice plan is needed to prevent exceedances of the applicable visible emission limitations.

iii. Pursuant to 40 CFR 63.309(f), compliance with the NESHAP, 40 CFR 63 Subpart L shall not be determined more often than the schedule provided for performance tests under 40 CFR 63.309. If additional valid emissions observations are obtained (or in the case

of charging, valid sets of emission observations), the arithmetic average of all valid values (or valid sets of values) obtained during the day shall be used in any computations performed to determine compliance under 40 CFR 63.309(d) or determinations under 40 CFR 63.306.

iv. Pursuant to 40 CFR 63.309(i), no observations obtained during any program for training or for certifying observers under 40 CFR 63 Subpart L shall be used to determine compliance with the requirements of 40 CFR 63 Subpart L or any other federally enforceable standard.

b. Pursuant to 40 CFR 63.308, for the collecting mains, the Permittee shall conduct daily inspections for leaks and promptly repair any leaks as specified by 40 CFR 63.308(a) through (d).

c. Pursuant to Section 39.5(7)(d) of the Act, the Permittee shall have daily inspections conducted for charging and doors, lids and off takes to confirm compliance by Battery A with 35 IAC 212.443(b), (d), (e) and (f) and by Battery B with LAER limit (See Conditions 7.2.3-1(c), 7.2.3-2(b), 7.2.3-3(b), and 7.2.3-4(b)). These inspections shall be conducted in accordance with applicable procedures in Condition 7.2.12(a). These inspections may be coordinated with the daily inspections required by the NESHAP, provided that appropriate observations are made and collected to address these applicable limits under state rule and permit.

7.2.8-2 Monitoring Requirements for Pushing

a. Pursuant to 40 CFR 63.7330(b), For each venturi scrubber applied to pushing emissions, the Permittee must at all times monitor the pressure drop and water flow rate using a CPMS according to the following requirements:

Pursuant to 40 CFR 63.7331(e), operate, and maintain CPMS to measure and record the pressure drop across the scrubber and scrubber water flow rate during each push according to the requirements in the site specific monitoring plan as well as the following:

i. Each CPMS must complete a measurement at least once per push [40 CFR 63.7331(e)(1)];

ii. Each CPMS must produce valid data for all pushes [40 CFR 63.7331(e)(2)]; and

iii. Each CPMS must determine and record the daily (24-hour) average of all recorded readings [40 CFR 63.7331(e)(3)].

b. Pursuant to 40 CFR 63.7330(d), For each capture system applied to pushing emissions, the Permittee must at all times operate and maintain a device to measure the fan RPM.

c. Pursuant to 40 CFR 63.7331(b), the Permittee must maintain and make available for inspection upon request by the Illinois EPA and USEPA a site-specific monitoring plan for each Continuous Parameter Monitoring System (CPMS) that addresses the following requirements:

i. Installation of the CPMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.*, on or downstream of the last control device) [40 CFR 63.7331(b)(1)];

ii. Performance and equipment specifications for the sample interface, the parametric signal analyzer, and the data collection and reduction system [40 CFR 63.7331(b)(2)];

iii. Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations) [40 CFR 63.7331(b)(3)];

iv. Ongoing operation and maintenance procedures in accordance with the general requirements of 40 CFR 63.8(c)(1), (3), (4)(ii), (7), and (8) [40 CFR 63.7331(b)(4)];

v. Ongoing data quality assurance procedures in accordance with the general requirements of 40 CFR 63.8(d) [40 CFR 63.7331(b)(5)]; and

vi. Ongoing recordkeeping and reporting procedures in accordance with the general requirements of 40 CFR 63.10(c), (e)(1), and (e)(2)(i) [40 CFR 63.7331(b)(6)].

d. Pursuant to 40 CFR 63.7331(d), the Permittee must operate and maintain the CPMS in continuous operation according to the site-specific monitoring plan.

e. Pursuant to 40 CFR 63.7332(a), except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times the affected source is operating.

f. Pursuant to 40 CFR 63.7332(b), the Permittee may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels, or in fulfilling a minimum data availability requirement, if applicable. You must use all the data collected during all other periods in assessing compliance. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitor to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

g. Pursuant to 40 CFR 63.7333(d)(3)(ii), check the fan RPM at least every 8 hours to verify the daily average fan RPM is at or above the minimum level in Condition 7.2.8-2(h) and recording the results of each check.

h. i. Pursuant to 40 CFR 63.7290(b)(1), for each venturi scrubber applied to pushing emissions, the Permittee must maintain the daily average pressure drop and scrubber water flow rate at or above (no lower than) the following minimum levels established as the site-specific operating limits during testing:

PCS Car	Scrubber Water Flow Rate, gal/min	Pressure Drop, in. wc
#3	860	37
#4	607	33

ii. Pursuant to 40 CFR 63.7290(b)(3)(ii), for each capture system the Permittee must maintain the daily average fan revolutions per minute (RPM) at or above (no lower than) the minimum level established as the site-specific operating limits during testing:

PCS Car	RPM
#3	1650
#4	1743

iii. Pursuant to 40 CFR 63.7323 (e)(1) through (3), the Permittee may change the operating limit for a venturi scrubber, capture system, or mobile control device that captures emissions during pushing if the Permittee meets the following requirements described below:

A. Submit a written notification to the Illinois EPA of Permittee's request to conduct a new performance test to revise the operating limit.

B. Conduct a performance test to demonstrate that emissions of particulate matter from the

control device do not exceed the applicable limit in 40 CFR 63.7290(a).

C. Establish revised operating limits according to the applicable procedures in 40 CFR 63.7323.

i. The Permittee shall comply with the work practice standards for fugitive pushing emissions as specified by 40 CFR 63.7291. In particular:

i. The Permittee shall observe and record the opacity of fugitive pushing emissions as required by 40 CFR 63.7291(a)(1), (a)(2), (a)(3) and (a)(4).

ii. The Permittee shall undertake corrective action(s) in the event that the opacity of fugitive pushing emissions exceeds the applicable limit, as required by 40 CFR 63.7291(a)(5) through (a)(7).

iii. Pursuant to 40 CFR 63.7291(b), the Permittee may request to use an alternative to the work practice standards in 40 CFR 63.7291(a) using the procedure provided in 40 CFR 63.6(g).

j. For each by-product coke oven battery with vertical flues subject to the work practice standards for fugitive pushing emissions in 40 CFR 63.7291(a), the Permittee must demonstrate continuous compliance according to the following requirements of 40 CFR 63.7334(a)(1) through (8):

i. The Permittee shall observe and record the opacity of fugitive emissions for four consecutive pushes per operating day, except the Permittee may make fewer or non-consecutive observations as permitted by 40 CFR 63.7291(a)(3). The Permittee shall maintain records of the pushing schedule for each oven and records indicating the legitimate operational reason for any change in the pushing schedule according to 40 CFR 63.7291(a)(4).

ii. The Permittee shall observe and record the opacity of fugitive emissions from each oven in a battery at least once every 90 days. If an oven cannot be observed during a 90-day period, the Permittee shall observe and record the opacity of the first push of that oven following the close of the 90-day period that can be read in accordance with the procedures in 40 CFR 63.7334(a)(1) through (8).

iii. The Permittee shall make all observations and calculations for opacity observations of fugitive pushing emissions in accordance with Method 9 in appendix A to 40 CFR Part 60 using a Method 9

certified observer unless the Permittee has an approved alternative procedure under 40 CFR 63.7334(a)(7).

iv. The Permittee shall record pushing opacity observations at 15-second intervals as required in section 2.4 of Method 9 Appendix A to 40 CFR Part 60. The following requirements do not apply: (section 2.4 of Method 9) for a minimum of 24 observations; the data reduction requirements in (section 2.5 of Method 9); and obtaining at least 3 hours of observations (thirty 6-minute averages) to demonstrate initial compliance (40 CFR 63.6(h)(5)(ii)(B)) does not apply.

v. If fewer than six but at least four 15-second observations can be made, the Permittee shall use the average of the total number of observations to calculate average opacity for the push. Missing one or more observations during the push (*e.g.*, as the quench car passes behind a building) does not invalidate the observations before or after the interference for that push. However, a minimum of four 15-second readings must be made by the Permittee for a valid observation.

vi. The Permittee shall begin observations for a push at the first detectable movement of the coke mass. The Permittee shall end observations of a push when the quench car enters the quench tower.

A. For a battery without a cokeside shed, the Permittee shall observe fugitive pushing emissions from a position at least 10 meters from the quench car that provides an unobstructed view and avoids interferences from the topside of the battery. This may require the observer to be positioned at an angle to the quench car rather than perpendicular to it. Typical interferences for the observer to avoid include emissions from open standpipes and charging. Opacity of emissions shall be observed above the battery top with the sky as the background where possible. The Permittee shall record the oven number of any push not observed because of obstructions or interferences.

B. An observer may reposition after the push to observe emissions during travel if necessary.

vii. If it is infeasible to implement the procedures in 40 CFR 63.7334 (a)(1) through (6) for an oven due to physical obstructions, nighttime pushes, or other reasons, the Permittee may apply to an appropriate permitting authority (USEPA) for permission to use an alternative procedure. The application must provide a detailed explanation of why it is infeasible to use the procedures in 40 CFR 63.7334 (a)(1) through (6), identify the oven and battery numbers, and describe the alternative procedure. An alternative procedure must identify whether the coke in that oven is not completely coked, either before, during, or after an oven is pushed.

viii. For each oven observed that exceeds an opacity of 30 percent for any short battery, the Permittee must take corrective action and/or increase the coking time in accordance with 40 CFR 63.7291(a). The Permittee shall maintain records documenting conformance with the requirements in 40 CFR 63.7291(a).

k. Pursuant to Section 39.5(7)(d) of the Act, the Permittee shall have daily observations conducted for pushing to confirm compliance with 35 IAC 212.443(c)(1)(A) (Condition 7.2.3-5(a)). These observations shall be conducted in accordance with applicable procedures in Condition 7.2.12(b). These observations may be coordinated with the observations required by the NESHAP provided that appropriate observations are made and data collected to address the applicable standard under state rule. These observations shall also include, on a monthly basis, opacity observations for the stack of the mobile scrubber car.

l. For each coke oven battery with a capture system or control device applied to pushing emissions, the Permittee shall demonstrate continuous compliance with the operation and maintenance requirements in 40 CFR 63.7300(c) by meeting the following requirements outlined in 40 CFR 63.7335(b):

i. Making monthly inspections of capture systems according to 40 CFR 63.7300(c)(1) and recording all information needed to document conformance with these requirements; and

ii. Performing preventative maintenance for each control device according to 40 CFR 63.7300(c)(2) and recording all information needed to document conformance with these requirements.

7.2.8-3 Monitoring Requirements for Quenching

a. For each coke oven battery subject to the work practice standard for quenching in 40 CFR 63.7295(b), the Permittee must demonstrate continuous compliance according to the following requirements of 40 CFR 63.7334(e)(1) through (3):

i. Maintaining baffles in each quench tower such that no more than 5 percent of the cross-sectional area of the tower is uncovered or open to the sky as required in 40 CFR 63.7295(b)(1);

ii. Maintaining records that document conformance with the washing, inspection, and repair requirements in 40 CFR 63.7295(b)(2), including records of the ambient temperature on any day that the baffles were not washed; and

iii. Maintaining records of the source of makeup water to document conformance with the requirement for acceptable makeup water in 40 CFR 63.7295(a)(2).

b. Pursuant to 40 CFR 63.7295(b), for the quench tower, the Permittee shall perform inspections on at least a monthly basis for damaged or missing baffles and initiate repair or replacement within 30 days, which shall be completed as soon as practicable, as specified by 40 CFR 63.7295(b)(3) and (4).

7.2.8-4 Monitoring Requirements for Combustion Stacks

a. Pursuant to 40 CFR 63.7330(e), for each coke oven battery stack, the Permittee must operate and maintain a COMS to measure and record the opacity of emissions exiting each stack according to the requirements in 40 CFR 63.7331(j)(1) through (5) and the following below:

i. The Permittee must operate, and maintain each COMS according to the requirements in 40 CFR 63.8(e) and Performance Specification 1 in 40 CFR Part 60, Appendix B. The Permittee shall identify periods the COMS is out-of-control, including any periods that the COMS fails to pass a daily calibration drift assessment, quarterly performance audit, or annual zero alignment audit.

ii. The Permittee must conduct a performance evaluation of each COMS according to the requirements in 40 CFR 63.8 and Performance Specification 1 in Appendix B to 40 CFR Part 60.

iii. The Permittee must develop and implement a quality control program for operating and maintaining each

COMS according to the requirements in 40 CFR 63.8(d). At minimum, the quality control program must include a daily calibration drift assessment, quarterly performance audit, and an annual zero alignment audit of each COMS.

iv. Each COMS installed, operated and maintained by the Permittee must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period. The Permittee must reduce the COMS data as specified in 40 CFR 63.8(g)(2).

v. The Permittee must determine and record the hourly and daily (24-hour) average opacity according to the procedures in 40 CFR 63.7324(b) using all the 6-minute averages collected for periods during which the COMS is not out-of-control.

b. Pursuant to Sections 39.5(7)(d) and (p) of the Act, the Permittee shall also record 6-minute average opacity data from the COMS required by Condition 7.2.8-4(a).

7.2.8-5 Monitoring Requirements for Emergency By-pass Bleeder Stacks

Pursuant to 40 CFR 63.309(h)(1), for a flare installed to meet the requirements of 40 CFR 63.307(b) (see Condition 7.2.3-8(b)):

If any emergency by-pass bleeder stack flare operates more than 5 minutes (cumulative) during any 2 hour period, visible emissions observations shall be conducted by using Method 22 in Appendix A of 40 CFR Part 60.

7.2.9 Recordkeeping Requirements

The Permittee shall maintain records of the following items for the affected coke production operations, pursuant to Sections 39.5(7)(a) and (e) of the Act:

a. 40 CFR 63, Subpart CCCCC (40 CFR 63.7334(d))

For each by-product coke oven battery subject to the work practice standard for soaking in 40 63.7294(a), the Permittee must demonstrate continuous compliance by maintaining records that document conformance with requirements in 40 CFR 63.7294(a)(1) through (5).

b. 40 CFR 63, Subpart CCCCC (40 CFR 63.7342 and 63.7343)

i. The Permittee shall keep the following records specified in 40 CFR 63.7342 (a)(1) through (3):

A. A copy of each notification and report that the Permittee submitted to comply with 40 CFR 63 Subpart CCCCC, including all documentation supporting any initial notification or notification of compliance status that the Permittee submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv).

B. The records in 40 CFR 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

C. Records of performance tests, performance evaluations, and opacity observations as required in 40 CFR 63.10(b)(2)(viii).

ii. For each COMS or CEMS, the Permittee shall keep the following records specified in 40 CFR 63.7342(b)(1) through (4):

A. Records described in 40 CFR 63.10(b)(2)(vi) through (xi).

B. Monitoring data for COMS during a performance evaluation as required in 40 CFR 63.6(h)(7)(i) and (ii).

C. Previous (that is, superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3).

D. Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

iii. The Permittee shall keep the records in 40 CFR 63.6(h)(6) for visual observations [40 CFR 63.7342(c)].

iv. The Permittee shall keep the records required in 40 CFR 63.7333 through 63.7335 to show continuous compliance with each emission limitation, work practice standard, and operation and maintenance requirement that applies to the Permittee [40 CFR 63.7342(d)].

v. The Permittee shall keep its records in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1) [40 CFR 63.7343(a)].

vi. As specified in 40 CFR 63.10(b)(1), the Permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record [40 CFR 63.7343(b)].

vii. The Permittee shall keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). The Permittee may keep the records offsite for the remaining 3 years [40 CFR 63.7343(c)].

c. 40 CFR 63, Subpart CCCCC (40 CFR 63.7326)

i. Pursuant to 40 CFR 63.7326(a)(2), For each venturi scrubber applied to pushing emissions, the Permittee shall have a record of the pressure drop and scrubber water flow rate measured during the performance test in accordance with 40 CFR 63.7323(a).

ii. Pursuant to 40 CFR 63.7326(a)(4)(iii), For each capture system applied to pushing emissions, the Permittee shall have a record of the fan RPM measured during the performance test in accordance with 40 CFR 63.7323(c)(3).

d. 40 CFR Part 63, Subpart L (40 CFR 63.311(f) and (g))

The Permittee shall maintain files of all required information in a permanent form suitable for inspection at an onsite location for at least 1 year and must thereafter be accessible within 3 working days to the Administrator for the time period specified in 40 CFR 70.6(a)(3)(ii)(B). Copies of the work practice plan developed under 40 CFR 63.306 and the startup, shutdown, and malfunction plan developed under 40 CFR 63.310 shall be kept onsite at all times. The Permittee shall maintain the following information:

i. A copy of the work practice plan required by 40 CFR 63.306 and any revision to the plan [40 CFR 63.311(f)(3)];

ii. If the Permittee is required under 40 CFR 63.306I to implement the provisions of a work practice plan for a particular emission point, the following records shall be maintained by the Permittee regarding the implementation of plan requirements for that emission point during the implementation period [40 CFR 63.311(f)(4)]:

A. Copies of all written and audiovisual materials used in the training, the dates of each class, the names of the participants in each class, and documentation that all appropriate personnel have successfully completed the training required under 40 CFR 63.306(b)(1);

B. The records required to be maintained by the plan provisions implementing 40 CFR 63.306(b)(7);

C. Records resulting from audits of the effectiveness of the work practice program for the particular emission point, as required under 40 CFR 63.306(b)(2)(i), 63.306(b)(3)(i), 63.306(b)(4)(i), or 63.306(b)(5)(i); and

D. If the plan provisions for coke oven doors must be implemented, records of the inventory of doors and jambs as required under 40 CFR 63.306(b)(2)(vi).

iii. The design drawings and engineering specifications for the bypass/bleeder stack flare system or approved alternative control device or system as required under 40 CFR 63.307 [40 CFR 63.311(f)(5)].

iv. Records specified in 40 CFR 63.310(f) regarding the basis of each malfunction notification [40 CFR 63.311(f)(6)].

v. Records required to be maintained and reports required to be filed with the Illinois EPA under Subpart L shall be made available in accordance with the requirements of 40 CFR 63.311(g) by the Permittee to the authorized collective bargaining representative of the employees at a coke oven battery, for inspection and copying.

A. Requests under 40 CFR 63.311(g) shall be submitted in writing, and shall identify the records or reports that are subject to the request with reasonable specificity;

B. The Permittee shall produce the reports for inspection and copying within a reasonable period of time, not to exceed 30 days. A reasonable fee may be charged for copying (except for the first copy of any document), which shall not exceed the copying fee charged by the Illinois EPA under the Act;

C. Nothing in 40 CFR 63.311(g) shall require the production for inspection or copying of any portion of a document that contains trade secrets or confidential business information that the Illinois EPA would be prohibited from disclosing to the public under the Act; and

D. The inspection or copying of a document under 40 CFR 63.311(g) shall not in any way affect any property right of the owner or operator in such document under laws for the protection of intellectual property, including the copyright laws.

e. Implementation of the good air pollution control practices, as required by Condition 7.2.5-3(b)(i), shall be supported by maintaining logs or other records for the implementation of operation practices and for maintenance activities performed by Permittee.

f. Records of the total annual coke production at batteries "A" and "B" (ton/yr) and separately for the Battery B [39.5(7)(b) of the Act].

g. Records for Startups of Affected coke ovens, pursuant to Section 39.5(7)(b) of the Act

i. The Permittee shall maintain startup procedures for each affected coke oven, as required by Condition 7.2.5-4(b).

ii. The Permittee shall maintain the following records for each startup of an affected coke oven:

A. Date, time and duration of the startup.

B. A description of the startup and reason(s) for the startup.

C. Whether a violation of an applicable standard may have occurred during startup accompanied by the information in Condition 7.2.9(g)(iv) if a violation may have or did occur.

D. Whether the established startup procedures, maintained above, were followed accompanied by the information in Condition 7.2.9(g)(iii) if there were departure(s) from those procedures.

iii. If the established startup procedures were not followed during a startup, the Permittee shall maintain the following records:

A. A description of the departure(s) from the established procedures.

B. The reason(s) for the departure(s) from the established procedures.

C. An explanation of the consequences of the departure(s) for emissions, such as whether the departure(s) prolonged the startup or resulted in additional emissions, and if so:

1. The actions taken to minimize emissions and the duration of the startup; and

2. An explanation whether similar incidents might be prevented in the future and if so, the corrective actions taken or to be taken to prevent similar incidents.

iv. If a violation did or may have occurred during a startup, the Permittee shall maintain the following records:

A. Identification of the applicable standard(s) that were or may have been violated.

B. An explanation of the nature of such violation(s), including the magnitude of such excess emissions.

C. A description of the actions taken to minimize the magnitude of emissions and duration of the startup.

D. An explanation whether similar incidents could be prevented or ameliorated in the future and if so, a description of the actions taken or to be taken to prevent similar incidents in the future.

h. Records for Malfunctions or Breakdowns

Pursuant to 35 IAC 201.263, the Permittee shall maintain records of continued operation of the affected coke ovens as addressed by Condition 7.2.5-4, during malfunctions or breakdowns, which at a minimum, shall include the following records. The preparation of these records shall be completed within 45 days of an incident, unless the Permittee conducts a root cause analysis for the incident, in which case the preparation of these records, other than

the root cause analysis, shall be completed within 120 days of the incident.

i. Date, time and duration of the incident.

ii. A detailed description of the incident, including:

A. A chronology of significant events during and leading up to the incident.

B. Relevant operating data for the unit, including information such as operator log entries and directives provided by management during the incident.

C. The measures taken to reduce the quantity of emissions and the duration of the incident including the resources utilized to address the incident.

D. The magnitude of emissions during the incident.

iii. An explanation why continued operation of an affected coke oven was necessary to prevent personnel injury or prevent equipment damage.

iv. A discussion of the cause(s) or probable cause(s) of the incident including the following:

A. Whether the incident was sudden, unavoidable, or preventable, including:

1. Why the equipment design did not prevent the incident;

2. Why better maintenance could not have avoided the incident;

3. Why better operating practices could not have avoided the incident; and

4. Why there was no advance indication for the incident.

B. Whether the incident stemmed from any activity or event that could have been foreseen, avoided or planned for,

C. Whether the incident was or is part of a recurring pattern indicative of inadequate design, operation or maintenance.

v. A description of any steps taken to prevent similar future incidents or reduce their frequency and severity.

vi. As an alternative to keeping the records required by Condition 7.2.9(h)(iv), the Permittee may perform a root cause analysis. For this purpose, a root cause analysis is an analysis whose purpose is to determine, correct and eliminate the primary causes of the incident and the excess emissions resulting there from. If the Permittee performs a root cause analysis method that would define the problem, define all causal relationships, provide a causal path to the root cause, delineate the evidence, and provide solutions to prevent a recurrence. Such an analysis shall be completed within one year of the incident.

i. Quench stations

The Permittee shall maintain the following records for quenching operations:

i. A file listing the emissions factors used by the Permittee to determine the emissions of the various quenching operations, with supporting documentation and analysis. These records shall be prepared and copies sent to the Illinois EPA in accordance with Condition 5.9.6(c).

ii. Records for the total number of quenches (ovens pushed), the total amount of coke quenched (tons) and the average amount of coke per quench (tons/quench) on a monthly and annual basis*.

iii. A log showing each period of time when coke was quenched at the East Quench Station, with number of quenches during the period and explanation of reason for use of the East Quench Station.

iv. Records on an annual basis* for the:

A. Total number of quenches.

B. For the East Quench Station:

1. Total number of quenches and amount of coke quenched at the East Quench Station.

2. Total number of quenches and amount of coke quenched at the East Quench Station due to malfunction and breakdown.

3. Percentage of total quenches that occurred at the East Quench Station.

C. For the emergency quench station:

1. Total number of quenches and amount of coke quenched at the emergency quench station.

2. Percentage of total quenches that occurred at the emergency quench station.

* These records shall be kept for the 12-month period from July 1 to June 30 and the initial 12-month period following shakedown of the West Quench Station with new quench tower.

v. Records for emissions of PM, PM_{10}, and $PM_{2.5}$ from each affected quench station and from the emergency quench station (tons/month and tons/year), with supporting calculations.

j. i. A file containing the emission rates (lb/hr and lb/ton) used by the Permittee to determine PM emissions from the mobile quench cars, with supporting documentation, which rates shall be reviewed when new data becomes available to assure that these rates do not understate actual emissions. These records shall be prepared and copies sent to the Illinois EPA in accordance with Condition 5.9.6(c).

ii. Records of PM emissions of the mobile scrubber cars (tons/month and tons/year), with supporting calculations.

k. i. Monthly and annual records of supplementary natural gas usage (scf) for underfiring the coke oven batteries and associated emissions (tons) with supporting calculations.

ii. Records of emissions as addressed in Condition 7.2.6(c).

l. Records of observations of duration of charging, percentage of leaks or opacity that are conducted by the Permittee or on its behalf to determine compliance with 35 IAC 212.443(b) and (c)(1)(A) in addition to the observations required by Condition 7.2.8-1 and 7.2.8-2.

m. Records of all test reports and submittals related to emission testing required by Section 7.2 of this permit.

7.2.10 Reporting Requirements

a. Opacity Monitoring Reports for Combustion Stacks

Pursuant to Sections 39.5(7)(a), (d) and (p) of the Act, the Permittee shall provide the following reports for each coke oven battery to the Illinois EPA, including a copy directly to Collinsville Regional Office, on a quarterly basis.

i. "Excess opacity reports" that list all opacity measurements which exceed 30 percent, averages over a six minute period. These reports shall also provide, for each such incident, the percent opacity measured as well as the date and span of such incident. These reports shall state the reasons for excess opacity. These reports shall also specify the date of those periods during which the continuous monitoring system was not in operation.

ii. "Summary reports" that provide the average opacity, 6-minute average, measured during the reporting period and the distribution of opacity measurements, 6-minute average and hourly average, during the reporting period, by percent, in ranges as follows:

Ranges	
6-Minute Averages	Hourly Averages
≤ 2	≤ 1
> 2 and ≤ 5	> 1 and ≤ 3
> 5 and ≤ 10	> 3 and ≤ 6
> 10 and ≤ 15	> 6 and ≤ 10
> 15 and ≤ 20	> 10 and ≤ 15
> 20 and ≤ 30	> 15
> 30	

b. 40 CFR Part 63, Subpart CCCCC (40 CFR 63.7336)

Pursuant to 63.7336(a) the Permittee must report each instance in which it did not meet each emission limitation in Conditions 7.2.3-5(c), 7.2.3-6(a) and 7.2.3-7(b). This includes periods of startup, shutdown, and malfunction. The Permittee must also report each instance in which it did not meet each work practice standard or operation and maintenance requirement in Condition 7.2.8-2(h). These instances are deviations from the emission limitations (including operating limits), work practice standards, and operation and maintenance requirements. These deviations must be reported according to the requirements in 40 CFR 63.7341.

c. 40 CFR Part 63, Subpart CCCCC (40 CFR 63.7341)

i. Pursuant to 40 CFR 63.7341(a)(3) and (4), compliance report due dates. Unless the Illinois EPA has approved a different schedule, the Permittee shall submit quarterly compliance reports for battery

stacks and semiannual compliance reports for all other affected sources to the Illinois EPA according to the following requirements:

A. All quarterly compliance reports for battery stacks must be postmarked or delivered no later than one calendar month following the end of the quarterly reporting period. All semiannual compliance reports must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

B. If the Illinois EPA has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A), the Permittee may submit compliance reports according to the dates the Illinois EPA has established instead of according to the dates in 40 CFR 63.7341(a)(1) through (3).

ii. Quarterly compliance report contents. Each quarterly report must provide information on compliance with the emission limitations for battery stacks in 40 CFR 63.7296. The reports must include the information in 40 CFR 63.7341(c)(1) through (3), and as applicable, 40 CFR 63.7341(c)(4) through (8).

iii. Semiannual compliance report contents. Each compliance report must provide information on compliance with the emission limitations, work practice standards, and operation and maintenance requirements for all affected sources except battery stacks. The reports must include the following information [40 CFR 63.7341(c)]:

A. Company name and address.

B. Statement by a responsible official, with the official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

C. Date of report and beginning and ending dates of the reporting period.

D. If the Permittee had a startup, shutdown, or malfunction during the reporting period and the Permittee took actions consistent with the startup, shutdown, and malfunction plan, the compliance report must include the information in 40 CFR 63.10(d)(5)(i).

E. If there were no deviations from the continuous compliance requirements in 40 CFR 63.7333(e) for battery stacks, a statement that there were no deviations from the emission limitations during the reporting period. If there were no deviations from the continuous compliance requirements in 40 CFR 63.7333 through 63.7335 that apply to the Permittee (for all affected sources other than battery stacks), a statement that there were no deviations from the emission limitations, work practice standards, or operation and maintenance requirements during the reporting period.

F. If there were no periods during which a continuous monitoring system (including COMS, continuous emission monitoring system (CEMS), or CPMS) was out-of-control as specified in 40 CFR 63.8(c)(7), a statement that there were no periods during which a continuous monitoring system was out-of-control during the reporting period.

G. For each deviation from an emission limitation in Subpart CCCCC (including quench water limits) and for each deviation from the requirements for work practice standards in Subpart CCCCC that occurs at an affected source where the Permittee is not using a continuous monitoring system (including a COMS, CEMS, or CPMS) to comply with the emission limitations in Subpart CCCCC, the compliance report must contain the following information (this includes periods of startup, shutdown, and malfunction):

1. The total operating time of each affected source during the reporting period.

2. Information on the number, duration, and cause of deviations (including unknown cause, if applicable) as applicable and the corrective action taken.

H. For each deviation from an emission limitation occurring at an affected source where the Permittee is using a continuous monitoring system (including COMS, CEMS, or CPMS) to comply with the emission limitation in Subpart CCCCC, the Permittee shall include the

following information (this includes periods of startup, shutdown, and malfunction):

1. The date and time that each malfunction started and stopped.

2. The date and time that each continuous monitoring system (including COMS, CEMS, or CPMS) was inoperative, except for zero (low-level) and high-level checks.

3. The date, time, and duration that each continuous monitoring system (including COMS, CEMS, or CPMS) was out-of-control, including the information in 40 CFR 63.8(c)(8).

4. The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

5. A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

6. A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

7. A summary of the total duration of continuous monitoring system downtime during the reporting period and the total duration of continuous monitoring system downtime as a percent of the total source operating time during the reporting period.

8. An identification of each HAP that was monitored at the affected source.

9. A brief description of the process units.

10. A brief description of the continuous monitoring system.

11. The date of the latest continuous monitoring system certification or audit.

12. A description of any changes in continuous monitoring systems, processes, or controls since the last reporting period.

iv. Immediate startup, shutdown, and malfunction report. If the Permittee had a startup, shutdown, or malfunction during the semiannual reporting period that was not consistent with the Permittee's startup, shutdown, and malfunction plan, the Permittee shall submit an immediate startup, shutdown, and malfunction report according to the requirements in 40 CFR 63.10(d)(5)(ii).

d. 40 CFR Part 63, Subpart L (40 CFR 63.311)

i. Semiannual compliance certification. The Permittee shall include the following information in the semiannual compliance certification [40 CFR 63.311(d)]:

A. Certification, signed by the Permittee, that no coke oven gas was vented, except through the bypass/bleeder stack flare system of a by-product coke oven battery during the reporting period or that a venting report has been submitted according to the requirements in 40 CFR 63.311(e).

B. Certification, signed by the Permittee, that a startup, shutdown, or malfunction event did not occur for a coke oven battery during the reporting period or that a startup, shutdown, and malfunction event did occur and a report was submitted according to the requirements in 40 CFR 63.310(e).

C. Certification, signed by the Permittee, that work practices were implemented if applicable under 40 CFR 63.306.

ii. Report for the venting of coke oven gas other than through a flare system. The Permittee shall report any venting of coke oven gas through a bypass/bleeder stack that was not vented through the bypass/bleeder stack flare system to the Administrator as soon as practicable but no later than 24 hours after the beginning of the event. A written report shall be submitted within 30 days of the event and shall include a description of the event and, if applicable, a copy of the notification for a

hazardous substance release required, pursuant to 40 CFR 63.311(e).

iii. 40 CFR Part 63, Subpart L (40 CFR 63.310)

A. Pursuant to 40 CFR 63.310(d), in order for the provisions of 40 CFR 63.310(i) to apply with respect to the observation (or set of observations) for a particular day, notification of a startup, shutdown, or a malfunction shall be made by the Permittee:

If practicable, to the certified observer if the observer is at the source during the occurrence; or to the enforcement agencies (USEPA and Illinois EPA), in writing, within 24 hours of the occurrence first being documented by personnel, and if the notification to the certified observer was not made, an explanation of why no such notification was made.

B. Pursuant to 40 CFR 63.310(e), within 14 days of the notification made under 40 CFR 63.310 (d), or after a startup or shutdown, the Permittee shall submit a written report to the Illinois EPA that describes the time and circumstances of the startup, shutdown, or malfunction; and describes actions taken that might be considered inconsistent with the startup, shutdown, or malfunction plan.

e. i. Pursuant to Section 39.5(7)(f)(ii) of the Act, the Permittee shall promptly notify the Illinois EPA, Air Compliance Section, within 30 days of deviations by the affected coke oven operations from applicable requirements unless a NESHAP standard specifies a different timeframe as identified in Condition 7.2.11(c) and (d), as follows:

A. Requirements in Condition 7.2.3(d).

B. Requirements in Condition 7.2.3-1.

C. Requirements in Condition 7.2.3-2.

D. Requirements in Condition 7.2.3-3.

E. Requirements in Condition 7.2.3-4.

F. Requirements in Condition 7.2.3-5.

G. Requirements in Condition 7.2.3-6.

H. Requirements in Condition 7.2.3-7.

I. Requirements in Condition 7.2.3-8.

J. Requirements in Condition 7.2.5-1.

K. Requirements in Condition 7.2.5-2.

L. Requirements in Condition 7.2.6.

ii. All such deviations shall be summarized and reported as part of the semiannual monitoring report required by Condition 8.6.1.

iii. The Permittee shall notify the Illinois EPA, Air Compliance Section, of all other deviations as part of the semiannual monitoring reports required by Condition 8.6.1.

iv. All deviation reports described in Condition 7.2.10(e) above shall contain the following:

A. Date, time and duration of the deviation;

B. Description of the deviation;

C. Probable cause of the deviation; and

D. Any corrective actions or preventive measures taken.

f. Quench stations [08060026]

The Permittee shall provide the following notification and reports to the Illinois EPA, Air Compliance Section and Regional Field Office, pursuant to 35 IAC 201.263, concerning continued operation of quenching operations during malfunction or breakdown that does not meet the requirements of 35 IAC 212.443(h)(1):

i. For noncompliance due to malfunction or breakdown that lasts more than 30 minutes (quenching of four ovens):

A. The Permittee shall notify the Illinois EPA's regional office by telephone as soon as possible during normal working hours, but no later than the next Agency business day.

B. Upon achievement of compliance, the Permittee shall give a written follow-up notice within 15 days to the Illinois EPA, Air Compliance Section and Regional Field Office, providing a detailed explanation of the event, the length of time during which operation continued under such conditions, the measures taken by the Permittee to minimize and correct deficiencies

with chronology, and when the repairs were completed.

C. If compliance is not achieved within 48 hours of the occurrence, the Permittee shall submit interim status reports to the Illinois EPA, Air Compliance Section and Regional Field Office, on a daily basis, until compliance is achieved. These interim reports shall provide a brief explanation of the nature of the malfunction or breakdown, corrective actions accomplished to date, actions anticipated to occur with schedule, and the expected date on which repairs will be complete.

ii. For noncompliance due to malfunction or breakdown that is no more than 30 minutes in duration, the Permittee shall provide the information for the incident or period with the periodic compliance reports required by 40 CFR 63, Subpart CCCCC.

iii. Within two years of initial startup of the low emission quench tower on the West Quench Station, the Permittee shall submit a report evaluating the reduction in filterable and total $PM_{2.5}$ and PM_{10} emissions achieved by this project, on both in terms of emissions per ton of coke quenched and in terms of annual emissions.

g. Reporting on the State malfunction and breakdown authorization shall be performed in accordance with Condition 5.10.5-2.

h. Reporting on the State startup authorization shall be performed in accordance with Condition 5.10.5-1.

i. Reporting on the Federal SSM authorization shall be performed in accordance with Condition 5.10.5-3.

7.2.11 Operational Flexibility/Anticipated Operating Scenarios

Operational flexibility is not set for the affected coke oven operations.

7.2.12 Compliance Procedures

For purposes of 35 IAC 212.443:

a. Coke Oven Charging, Leaks from Doors, Leaks from Lids and Leaks from Off Takes: Observations shall be conducted in accordance with 40 CFR 63, Appendix A, Method 303 which is consistent with the procedures specified in 35 IAC 280.104 to 280.107 and the Consent Decree, Civil Action No. 81-3009 referenced in Construction Permit C808048.

i. Battery A and B - Charging:

Observations shall be conducted in accordance with 40 CFR 63, Appendix A, Method 303 which is consistent with the procedures specified in 35 IAC 280.104 to 280.107 and the Consent Decree, Civil Action No. 81-3009 referenced in Construction Permit C808048.

Observation of charging emissions shall be made from any point or points on the topside of a coke oven battery from which a qualified observer can obtain an unobstructed view of the charging operation.

The qualified observer shall time the visible emissions with a stopwatch while observing the charging operation. Only emissions from the charge port and any part of the larry car shall be timed. The observation shall commence as soon as coal is introduced into the first charge port as indicated by the first charge port as indicated by the first mechanical movement of the coal feeding mechanism on the larry car and shall terminate when the last charge port lid has been replaced. Simultaneous emissions from more than one emission point shall be timed and recorded as one emission and shall not be added individually to the total time.

The qualified observer shall determine and record the total number of seconds that charging emissions are visible during the charging of coal to the coke oven.

For each charge observed, the qualified observer shall record the total number of seconds of visible emissions, the clock time for the initiation and completion of the charging operation and the battery identification and oven number.

The qualified observer shall not record any emissions observed after all charging port lids have been firmly seated following removal of the larry car, such as emissions occurring when a lid has been temporarily removed to permit spilled coal to be swept into the oven.

In the event that observations of emissions from a charge are interrupted due to events beyond the control of the observer, the data from that charge shall be invalidated and the observer shall note on his observation sheet the reason for invalidating the data. The observer shall then resume observation of the next consecutive charge or charges, and continue until he has obtained a set of consecutive charges immediately preceding the interrupted charge and the charge immediately following the interrupted charge shall constitute consecutive charges. Compliance

shall be determined by summing the seconds of charging emission observed during a set of five consecutive charges. Any one charge may be included in only one set of consecutive charges.

ii. Battery A and B - Doors:

Compliance with the percent door area leakage standard shall be determined in accordance with the following method:

Observations of door emissions shall be made from a minimum distance of 25 feet from each door. Each door shall be observed in sequence for only that period necessary to determine whether or not, at the time, there are visible emissions from any point on the door while the observer walks along the side of the battery. If the observer's view of a door is more than momentarily obstructed, as, for example, by door machinery, pushing machinery, coke guide, luter truck, or opaque steam plumes, he shall record the door obstructed and the nature of the obstruction and continue the observations with the next door in sequence which is not obstructed. The observer shall continue this procedure along the entire length of the battery for both sides and shall record the battery identification, battery side, and oven door identification number of each door exhibiting visible emissions. Before completing the traverse or immediately thereafter he shall attempt to reobserve the obstructed doors.

iii. Battery A and B - Charging Ports/Lids:

For purposes of determining compliance with limits on visible emissions from charging ports, observations of any visible emissions shall be made and recorded during the time an observer walks the topside of a battery from one end to the other. Each oven shall be observed in sequence. The observer may also observe off take pipe leaks during this traverse of the battery. The observer shall record the battery identification, the points of emissions from each oven, the oven number, and whether an oven was dampered off. Compliance shall be determined by application of the following formula which shall exclude the ports on up to 3 ovens ahead of the oven being pushed which are dampered off.

iv. Battery A and B - Off Takes:

For purposes of determining compliance with limits on visible emissions from off take pipes, observations of any visible emissions from the off take piping shall be made by traversing the topside of the

battery. During the traverse(s), the observer shall walk as near to the center of the battery as safety considerations permit but may walk as close as necessary to the off take piping to determine whether an observed emission is emanating from the off take piping. Each oven shall be observed in sequence. The observer may also observe charging port emissions during this traverse of the battery. The observer shall record the battery identification, the points of off take piping emission from any oven and the oven number.

b. Coke Oven Pushing:

i. Battery A and B:

Opacity readings shall be taken by a qualified observer located in a position where the oven being pushed, the coke receiving car and the path to the quench tower are visible. The opacity shall be read as the emissions rise and clear the top of the coke battery gas mains. The qualified observer shall record opacity readings of emissions originating at the receiving car and associated equipment and the coke oven, including the standpipe on the coke side of the oven being pushed. Opacity readings shall be taken in accordance with the procedures set forth in 40 CFR Part 60, Appendix A, Method 9, incorporated by reference in 35 IAC 212.113, except that Section 2.5 for data reduction shall not be used. The qualified observer referenced in this subsection shall be certified pursuant to 40 CFR Part 60, Appendix A, Method 9, incorporated by reference in 35 IAC 212.113.

ii. Battery A:

Opacity readings shall be taken at 15-second intervals, beginning from the time the coke falls into the receiving car or is first visible as it emerges from the coke guide whichever occurs earlier, until the receiving car enters the quench tower or quenching device. For a push of less than 90 seconds duration, the actual number of 15-second readings shall be averaged.

At least four consecutive pushes per day.

iii. Battery B:

Opacity readings shall be taken at 15-second intervals, beginning from the time the coke falls into the receiving car or is first visible as it emerges from the coke guide whichever occurs earlier, until the end of the sixth reading. During the

pushing operation, the observer shall observe all the pushing emissions including, but not limited to, fugitive emissions from the pushing emission control device and from open quench cars during travel.

At a minimum, one push per day.

c. Coke Quenching (35 IAC 212.443(h)(2))

i. Samples shall be taken from each quench station as separate grab samples or composite samples.

ii. Samples shall be collected a minimum of five days per week and analyzed to report a weekly concentration. The samples for each week shall be analyzed either:

A. Separately, with the average of the individual daily concentrations determined; or

B. As one composite sample, with equal volumes of the individual daily samples combined to form the composite sample.

7.2.13 State-Only Conditions

State-only conditions are not being established.

7.3 Coke By-Product Recovery Plant and COG Desulfurization System

7.3.1 Description

COG is made up of various organic materials volatilized during the coal-to-coke conversion process. The raw coke oven gas from U. S. Steel two existing coke oven batteries is processed in the coke by-product recovery plant, where various byproducts are removed. Once treated, the COG is used as a fuel in the coke batteries and in various boilers and furnaces throughout the facility.

Coke Oven Gas (COG) Processing Unit:

COG from the coke ovens first passes through the primary cooler where it is cooled. The cooling of COG causes tar, naphthalene, and liquor to condense. The cool COG is then pushed through the entire by-product plant with the aid of exhausters. More tar and liquor are removed by the centrifugal force created in the exhausters. Droplets of tar, naphthalene, and liquor accumulate and drain to the tar sump. Ammonia present in the COG is then removed by passing it through ammonia absorber. The removal of ammonia is accomplished by exposing the COG to a spray of sulfuric acid in the ammonia absorber. The COG then enters the Tar Spray Final Cooler where the COG is further cooled and most of the naphthalene is removed with tar injection. Next COG passes through the Light Oil Scrubber, which is designed to remove the remaining naphthalene and "Light Oils".

From the light oil scrubber, the treated COG is normally further processed in the COG desulfurization system to remove sulfur. The COG is not always processed by desulfurization system because of the need for periodic maintenance on the system. The permit limits the amount of time during which this may occur. COG desulfurization system consists of a packed tower amine unit, hydrogen cyanide destruction unit, and a Claus sulfur recovery unit with tail gas oxidizer. The system removes hydrogen sulfide (H_2S) from the treated COG stream from the by-product plant. The COG desulfurization system is not part of the by-products recovery plant.

The COG stream from the by-product plant is sent to a pressure holding tank from where the COG is distributed to underfire the Coke Oven Batteries and various parts of the plant.

Light Oil Processing Unit:

Processing the Light Oil generated at the Light Oil Scrubber, also called Benzol Washer, is the main activity of this unit. In the Light Oil Scrubber, wash oil is used to scrub out Light Oil from the Coke Oven Gas. Next wash oil is cleaned and re-circulated back through the Light Oil scrubber as described below.

After scrubbing out the light oil in the Light Oil Scrubber, the wash oil passes through two oil to vapor heat exchangers, where the light oil is vaporized. The vapors are then passed through two cool water condensers to condense out the light oil. The light oil then passes through the Secondary Light Oil Separator, where any remaining wash oil and water is removed. The liquid oil is then pumped into one of six storage tanks.

After passing through the oil to vapor heat exchangers, the wash oil passes through steam heaters, the Wash Oil Still, coolers, and finally the Wash Oil Recirculating Tank before it is reintroduced in the Light Oil Scrubber.

Coal Tar Processing:

Tar is collected into a tar sump. The tar is decanted by passing through one of three decanters. Sludge from the decanters is dumped into hoppers from where it is collected by a company for further treatment. Tar from the decanters pass through two dehydration tanks where the water is removed. The tar is then pumped to a storage tank, where it is stored until shipment.

Note: This narrative description is for informational purposes only and is not enforceable.

7.3.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Date Constructed	Emission Control Equipment
By-Product Recovery	Coke oven Gas Processing Unit (coke oven gas transfer and handling; gas coolers; gas processing/cleaning unit)	Prior to 06/1982	Steam Blanketing
By-Product Recovery (Continued)	Light Oil Processing (stills; process condensers; sumps) Coal Tar Processing (tar collection and transfer; tar storage tanks) Tar Storage Tanks; Dehydration Tanks; Decanters; Light Oil Storage Tanks; Ammonia Liquor; Storage Tanks	Prior to 06/1982	Clean Gas Blanketing; Steam Blanketing; Negative Pressure Systems

Emission Unit	Description	Date Constructed	Emission Control Equipment
	Railcar/Truck Loading	2004	Vapor Recovery System; Negative Pressure
COG Desulfurization System	Packed tower amine unit and hydrogen cyanide destruction unit		Closed Systems
	Claus Sulfur Recovery Unit		Thermal Oxidizer
COG Flare	COG holding tank and flare		None

7.3.3 Applicable Provisions and Regulations

a. i. The "affected by-product recovery plant" for the purpose of these unit-specific conditions, is the group of emission units and/operations in the coke by-product recovery plant described in Conditions 7.3.1 and 7.3.2.

ii. The COG desulfurization system is the system for desulfurization of treated COG described in Conditions 7.3.1 and 7.3.2.

iii. The COG flare is the system for burning of excess of COG described in Conditions 7.3.1 and 7.3.2.

b. The affected by-product recovery plant is subject to the work practices in 40 CFR Part 61, Subpart L, National Emission Standards for Benzene Emissions from Coke By-Product Recovery Plants.

c. The affected by-product recovery plant is subject to the work practices in 40 CFR Part 61, Subpart V, National Emission Standards for Equipment Leaks (Fugitive Emissions).

d. The affected by-product recovery plant is subject to the work practices in 40 CFR Part 61, Subpart FF, National Emission Standard for Benzene Waste Operations.

e. No person shall cause or allow the loading of any organic material into any stationary tank having a storage capacity of greater than 946 liters (250 gallons), unless such tank is equipped with a permanent submerged loading pipe or an equivalent device approved by the Illinois EPA according to the provisions of 35 IAC 201, and further processed consistent with 35 IAC 219.108, or unless such tank is a pressure tank as described in 35 IAC 219.121(a) or is

fitted with a recovery system as described in 35 IAC 219.121(b)(2) [35 IAC 219.122(b)].

f. The affected by-product recovery plant, COG desulfurization system and COG flare are subject to 35 IAC 212.123(a), no person shall cause or allow the emission of smoke or other particulate matter, with an opacity greater than 30 percent, into the atmosphere from any emission unit other than those emission units subject to the requirements of 35 IAC 212.122, except as allowed by 35 IAC 212.123(b) and 212.124.

g. SO_2 emissions from the affected by-product recovery plant and COG flare shall not exceed 2000 ppm pursuant to 35 IAC 214.301.

7.3.4 Non-Applicability of Regulations of Concern

a. The storage tanks used at the affected by-product recovery plant are not subject to 35 IAC 219.120 because of the exemption for vessels at coke by-product plants in 35 IAC 219.119(b).

b. The storage tanks used at the affected by-product recovery plant are not subject to 35 IAC 219.121 (Storage Containers of Volatile Petroleum Liquids (VPL)) because the liquids kept in those tanks are not the product of petroleum refinery and, therefore, do not meet the definition of VPL/petroleum liquids of 35 IAC Part 211.

c. This permit is issued based on the affected by-product recovery plant not being subject to the applicable requirements of 35 IAC 219.301 because there is 85% reduction of uncontrolled organic material that would otherwise be emitted into atmosphere, pursuant to 35 IAC 219.302.

d. The COG desulfurization system and COG flare are not subject to 40 CFR 63 Subpart L, National Emission Standards for Benzene Emissions from Coke By-Product Recovery Plants, because both COG systems are not involved in the separation and recovery of coal tar derivatives evolved from coal during the coking process of a coke oven battery.

e. This permit is issued based on the COG desulfurization system (thermal oxidizer) not being subject to 35 IAC 214.301 pursuant to 35 IAC 214.302, which provides that 35 IAC 214.301 shall not apply to processes designed to remove sulfur compounds from the flue gases of fuel combustion emission sources.

7.3.5 Operation of COG Flare during Malfunction and Breakdown

Pursuant to 35 IAC 201.149 and Part 201 Subpart I, subject to the following terms and conditions, the Permittee is authorized

to continue to operate the COG flare in excess of the applicable state standard in Condition 7.3.3(f) in the event of a malfunction or breakdown.

Note: This authorization is provided because the Permittee applied for such authorization in its CAAPP application, generally explaining why such continued operation would be required to prevent injury to personnel or severe damage to equipment, and describing the measures that will be taken to minimize emissions from any malfunctions and breakdowns.

a. This authorization only allows such continued operation as necessary to prevent injury to personnel or severe damage to equipment and does not extend to continued operation solely for the economic benefit of the Permittee.

b. Upon occurrence of excess emissions due to malfunction or breakdown, the Permittee shall, as soon as practicable, repair the COG flare, reduce flare load or remove it from service so that excess emissions cease.

c. The Permittee shall fulfill the applicable recordkeeping and reporting requirements of Conditions 7.3.10(h) and 5.10.5-2 For these purposes, time shall be measured from the start of a particular incident. The absence of excess emissions for a short period shall not be considered to end the incident if excess emissions resume.

d. Following notification to the Illinois EPA (see Condition 5.10.5-2(a)(i))of a malfunction or breakdown with excess emissions, the Permittee shall comply with all reasonable directives of the Illinois EPA with respect to such incident.

e. This authorization does not relieve the Permittee from the continuing obligation to minimize excess emissions during malfunction or breakdown. As provided by 35 IAC 201.265, an authorization in a permit for continued operation with excess emissions during malfunction and breakdown does not shield the Permittee from enforcement for any such violation and only constitutes a prima facie defense to such an enforcement action provided that the Permittee has fully complied with all terms and conditions connected with such authorization.

7.3.6 Control Requirements and Work Practices

a. 40 CFR Part 61, Subpart L:

i. The Permittee shall operate and maintain a Control System to meet the standards specified below in 40 CFR Part 61 Subpart L. This Control System consists of a Positive Pressure Gas Blanketing System supplied with clean coke oven gas controlling the light oil

area and a Negative Pressure or Steam Blanketing System controlling tar, ammonia and liquor tanks.

ii. These control systems shall be designed to operate with no detectable emissions (an organic chemical concentration more than 500 ppm above a background concentration), as determined by the methods specified in 40 CFR 61.245, pursuant to 40 CFR 61.132(b).

iii. The Permittee shall comply with 40 CFR 61.132 - Standard: Process vessels, storage tanks, and tar-intercepting sumps, which includes the following:

A. Each owner or operator of a furnace byproduct recovery plant shall enclose and seal all openings on each process vessel, tar storage tank, and tar-intercepting sump.

B. The owner or operator shall duct gases from each process vessel, tar storage tank, and tar-intercepting sump to the gas collection system, gas distribution system, or other enclosed point in the by-product recovery process where the benzene in the gas will be recovered or destroyed. This control positive pressure blanketing system shall be designed and operated for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined by the methods specified in 40 CFR 61.245(c).

1. Except, the owner or operator may elect to install, operate, and maintain a pressure relief device, vacuum relief device, an access hatch, and a sampling port on each process vessel, tar storage tank, and tar-intercepting sump. Each access hatch and sampling port must be equipped with a gasket and a cover, seal, or lid that must be kept in a closed position at all times, unless in actual use.

2. The owner or operator may elect to leave open to the atmosphere the portion of the liquid surface in each tar decanter necessary to permit operation of a sludge conveyor. If the owner or operator elects to maintain an opening on part of the liquid surface of the tar decanter, the owner or operator shall install, operate, and maintain a water leg seal on the tar decanter roof near the sludge

discharge chute to ensure enclosure of the major portion of liquid surface not necessary for the operation of the sludge conveyor.

C. Each owner or operator of a furnace coke by-product recovery plant also shall comply with the requirements of 40 CFR 61.132(a) through (c) for each benzene storage tank, BTX storage tank, light-oil storage tank, and excess ammonia-liquor storage tank.

iv. The Permittee shall comply with 40 CFR 61.133 - Standard: Light-oil sumps, which includes the following, pursuant to 40 CFR 61.133(a) and 61.133(c):

A. Each owner or operator of a light-oil sump shall enclose and seal the liquid surface in the sump to form a closed system to contain the emissions.

1. Except, the owner or operator may elect to install, operate, and maintain a vent on the light-oil sump cover. Each vent pipe must be equipped with a water leg seal, a pressure relief device, or vacuum relief device.

2. Except, the owner or operator may elect to install, operate, and maintain an access hatch on each light-oil sump cover. Each access hatch must be equipped with a gasket and a cover, seal, or lid that must be kept in a closed position at all times, unless in actual use.

3. The light-oil sump cover may be removed for periodic maintenance but must be replaced (with seal) at completion of the maintenance operation.

B. The venting of steam or other gases from the by-product process to the light-oil sump is not permitted [40 CFR 61.133(a)].

C. Following the installation of any control equipment used to meet the requirements of 40 CFR 61.133(a), the owner or operator shall monitor the connections and seals on each control system to determine if it is operating with no detectable emissions, using Method 21 (40 CFR Part 60, Appendix A) and the procedures specified in 40 CFR 61.245(c), and shall

visually inspect each source (including sealing materials) for evidence of visible defects such as gaps or tears. This monitoring and inspection shall be conducted semiannually and at any other time the cover is removed.

1. If an instrument reading indicates an organic chemical concentration more than 500 ppm above a background concentration, as measured by Method 21, a leak is detected.

2. If visible defects such as gaps in sealing materials are observed during a visual inspection, a leak is detected.

3. When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected.

4. A first attempt at repair of any leak or visible defect shall be made no later than 5 calendar days after each leak is detected [40 CFR 61.133(c)].

v. The Permittee shall comply with 40 CFR 61.135 - Standard: Equipment leaks.

A. Each piece of equipment in benzene service to which 40 CFR 61 Subpart L applies shall be marked in such a manner that it can be distinguished readily from other pieces of equipment in benzene service [40 CFR 61.135(c)].

B. Each owner or operator of equipment in benzene service shall comply with requirements of 40 CFR 61, Subpart V.

C. The provisions of 40 CFR 61.242-3 and 61.242-9 of Subpart V do not apply to Subpart L.

b. 40 CFR Part 61, Subpart V:

40 CFR 61.242-10: Standards: Delay of Repair

i. Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown.

ii. Delay of repair of equipment for which leaks have been detected will be allowed for equipment that is

isolated from the process and that does not remain in VHAP (volatile hazardous air pollutant) service.

iii. Delay of repair for valves will be allowed if:

A. The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair; and

B. When repair procedures are affected, the purged material is collected and destroyed or recovered in a control device complying with 40 CFR 61.242-11.

iv. Delay of repair for pumps will be allowed if:

A. Repair requires the use of a dual mechanical seal system that includes a barrier fluid system; and

B. Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

v. Delay of repair beyond a process unit shutdown will be allowed for a valve if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

c. 40 CFR 61 Subpart FF (61.355(a)(3) through (a)(5)).

i. Pursuant to 40 CFR 61.355(a)(3), if the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 tons/yr), then the owner or operator shall comply with the requirements of 40 CFR 61.342(c), (d), or (e).

ii. Pursuant to 40 CFR 61.355(a)(4), if the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 tons/yr) but is equal to or greater than 1 Mg/yr, (1.1 ton/yr), then the owner or operator shall:

A. Comply with the recordkeeping requirements of 40 CFR 61.356 and reporting requirements of 40 CFR 61.357; and

B. Repeat the determination of total annual benzene quantity from facility waste at least once per year and whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more.

iii. Pursuant to 40 CFR 61.355(a)(5), if the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall:

A. Comply with the recordkeeping requirements of 40 CFR 61.356 and reporting requirements of 40 CFR 61.357; and

B. Repeat the determination of total annual benzene quantity from facility waste whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more.

d. The COG flare shall be operated with a flame present at all times when COG is vented to the flare [Section 39.5(7)(a) of the Act].

7.3.7 Production and Emission Limits for the COG Desulfurization System from Permit 06070022

a. The Permittee shall operate COG desulfurization system (COG-DS) at all times the by-products plant is producing COG, except when undertaking maintenance or repairs of the system. This total "outage" period shall not exceed 35 days (840 hours) per calendar year.

b. i. Raw COG production during periods of time when the COG-DS is not operating shall not exceed 1,092 mmscf/year.

ii. Total amount of COG generated by Coke Oven Batteries A and B and processed by by-products plant shall not exceed 1,140 mmscf/month and 11,400 mmscf/year.

c. i. The COG-DS shall be operated and maintained in conformance with good air pollution control practices.

ii. The thermal oxidizer combustion chamber for the sulfur recovery unit shall be operated at a temperature that is greater than 1,100°F.

d. i. The H_2S content of the raw COG entering the COG-DS shall not exceed 500 grains of H_2S/100 scf of COG, daily average.

ii. The H_2S content of desulfurized COG exiting the COG-DS shall not exceed 66 grains/100 scf of COG, annual average.

iii. During periods of time when the COG-DS is operating, the H_2S content of COG shall not exceed the following limits: 25 grains of H_2S/100 scf of COG, monthly average, excluding outages, startup, shutdown, and upsets such as failure of fans, pumps or heat exchangers and aberrations in the composition or condition of the raw COG.

e. i. Emissions from the thermal oxidizer on the COG-DS shall not exceed the following limits:

PM_{10}		SO_2	
(Lbs/Hr)	(Tons/Yr)	(Lbs/Hr)	(Tons/Yr)
5.6	24.6	67.3	294.7

ii. Combined emissions of PM_{10} and SO_2 from the thermal oxidizer on COG-DS and combustion of coke oven gas shall not exceed 246.8 and 1,074.1 tons/year for PM_{10} and SO_2, respectively [T1].

iii. Compliance with the annual limits in Conditions 7.3.7(b) and (e) shall be determined from a running total of 12 months of data, unless otherwise specified [T1].

7.3.8 Testing Requirements

a. The Permittee, as the owner or operator of a by-products plant, subject to the provisions of 40 CFR Part 61 Subpart L, shall comply with the requirements in 40 CFR 61.245.

b. The Permittee shall determine the total annual benzene (TAB) quantity of the facility using the test methods and procedures for determination in 40 CFR 61.355(a)(5). In particular, if the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall repeat the determination of total annual benzene quantity from facility waste whenever there is a change in the process generating the waste that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more.

c. For the COG flare and the thermal oxidizer in the COG-DS, the Permittee shall conduct observations for visible emissions and/or opacity, using USEPA Method 22 and 9, respectively. These observations shall be conducted by individual(s) certified to observe opacity by USEPA Method 9. The observer(s) may either conduct observations for opacity or conduct observations for visible emissions, immediately followed by observations for opacity if visible

emissions are observed. Observations shall be conducted in at least a monthly basis for the COG flare and an annual basis for the COG-DS thermal oxidizer. In addition, for the COG flare, observations shall be coordinated with weather conditions so that at least two observations are made in each calendar year during elevated wind speed conditions, i.e., wind speed of at least 16 miles per hour.

d. Upon the written request from the Illinois EPA, the emission tests shall be conducted by the Permittee for the COG-DS to verify compliance with emission limits in Condition 7.3.7(e) as follows [Section 39.5(7)(d) and (p) of the Act]:

i. The following USEPA test methods shall be used, unless another USEPA method is approved by the Illinois EPA.

Location of Sample Points	Method 1
Gas Flow and Velocity	Method 2
Flue Gas Weight	Method 3
Moisture	Method 4
PM_{10}	Method 201 or 201A
SO_2	Method 6

ii. Observations of opacity shall be conducted during these emission tests in accordance with Method 9 and the results of these observations included in the reports for emission testing.

iii. For this emission testing, test notifications and reporting shall be done by the Permittee in accordance with Conditions 8.6.2 and 8.6.3 of this permit.

7.3.9 Monitoring Requirements

a. For the coke by-product recovery plant, when equipment operated in benzene service is tested for compliance with or monitored for no detectable emissions, the owner or operator shall comply with the following requirements [40 CFR 61.245(c)]:

i. The requirements of 40 CFR 61.245 (b) (1) through (4) shall apply.

ii. The background level shall be determined, as set forth in Method 21.

iii. The instrument probe shall be traversed around all potential leak interfaces as close to the interface as possible as described in Method 21.

iv. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

b. Alternatives procedures are not established for each exhauster, as provided by 40 CFR 61.135(e) through (g) and 40 CFR 61.136(d). Therefore, pursuant to 40 CFR 61.135(d), each exhauster shall be monitored quarterly to detect leaks 10,000 ppm or greater by the methods specified in 40 CFR 61.245(b).

c. For the coke by-product recovery plant, the owner or operator shall monitor the connections and seals on each control system to determine if it is operating with no detectable emissions, using Method 21 (40 CFR Part 60, Appendix A) and procedures specified in 40 CFR 61.245(c), and shall visually inspect each source (including sealing materials) and the ductwork of the control system for evidence of visible defects such as gaps or tears. This monitoring and inspection shall be conducted on a semiannual basis and at any other time after the control system is repressurized with blanketing gas following removal of the cover or opening of the access hatch.

i. If an instrument reading indicates an organic chemical concentration more than 500 ppm above a background concentration, as measured by Method 21, a leak is detected.

ii. If visible defects such as gaps in sealing materials are observed during a visual inspection, a leak is detected.

iii. When a leak is detected, it shall be repaired by the Permittee as soon as practicable, but not later than 15 calendar days after it is detected.

iv. A first attempt at repair of any leak or visible defect shall be made by the Permittee no later than 5 calendar days after each leak is detected.

d. Pursuant to 40 CFR Part 61.132(a), the Permittee shall operate and maintain Control Systems on the coke by-product plant in accordance with the work practices in 40 CFR Part 61 Subpart L, as specified below. This Control System consists of a Positive Pressure Gas Blanketing System supplied with clean coke oven gas controlling the light oil area and a Negative Pressure or Steam Blanketing System controlling tar, ammonia and liquor tanks.

i. The following procedures shall be conducted on the control system on a semiannual basis and after each time the control system is repressurized and the Permittee shall [40 CFR 61.132(b)]:

A. Inspect the ductwork for evidence of visible defects such as gaps or tears.

B. Monitor the connections and seals to determine if operating with no detectable emissions.

ii. A maintenance inspection of the control system shall be conducted on an annual basis for evidence of system abnormalities such as blocked or plugged lines, sticking valves, plugged condensate traps and other maintenance defects that could result in abnormal system operation. The owner or operator shall make a first attempt at repair within 5 days, with repair within 15 days of detection [40 CFR 61.132(c)].

e. COG flare

Pursuant to Sections 39.5(7)(a) and (d) of the Act, for the COG flare:

i. The Permittee shall either:

A. Install, operate and maintain instrumentation, with alarm, to confirm the presence of a flame at the flare tip; or

B. Monitor for the presence of a pilot flame using a thermocouple or other equivalent device to detect the presence of a flame; or

C. Verify, once per shift, the presence of a flame at the tip of the flare, and that the flare gas header has a positive pressure.

ii. The Permittee shall perform the following inspections of the flare:

A. An inspection of the ignition system on an annual basis;

B. A detailed maintenance and repair inspection during the period when the flare is out of service and/or idled.

f. Monitoring requirements for COG established by FESOP 94120017, Permit 06070022 and Section 39.5(7)(a) of the Act:

i. The Permittee shall operate systems for monitoring the hydrogen sulfide (H_2S) content of the COG exiting the affected by-product plant and exiting the COG-DS.

The H_2S concentration shall be measured on a wet gas basis.

ii. These H_2S monitoring systems shall be equipped with a strip chart recorder or disk storage and shall be capable of recording the H_2S content in grains per standard cubic feet.

iii. These H_2S monitoring systems shall meet the applicable requirements of Performance Specification 7 of 40 CFR 60, Appendix B. These H_2S monitoring systems shall be operated, and data collected, reduced and maintained, in accordance with the applicable requirements of 40 CFR 60.13 and 35 IAC Part 201 Subpart L.

iv. The H_2S monitoring system for COG exiting the by-product plant shall comply with the following requirements for collection of data:

A. The system shall collect hourly average H_2S content data for at least 75% of the daily operating hours in which COG is not treated by the COG-DS (e.g., at 24 hours/day COG production, at least 18 hourly averages of H_2S content must be obtained). In the event that this minimum data requirement cannot be met by the H_2S monitoring system, the H_2S content data shall be supplemented or obtained by one of the following alternative methods.

I. H_2S determined by type of coal used during that period and previous recorded H_2S content when using this coal type. This method shall only be used for a maximum of 15 days per calendar year.

II. A manual sample of COG shall be taken daily and the H_2S content shall be determined by 40 CFR 60, Appendix A, Method 11, as adapted to measure higher ranges of H_2S. This value, or a value based on the mean of the daily values plus two standard deviations for the previous 90 days for which a reading was obtained, whichever is higher, shall be used. Should a coal blend change occur during the period this alternative method is being used, the mean value plus two standard deviations will be adjusted to reflect any potential change in the H_2S content from that of the previous coal blend.

B. The system shall collect H_2S content data for at least 75% of the daily operating hours in which COG is treated by the COG-DS with this data being the average over at least 5 minutes in each such operating hour. In the event that this minimum data requirement cannot be met by the H_2S monitoring system or can only be met with manual cycling of the H_2S monitoring system for treated COG data shall be supplemented or obtained by one of the following alternative methods:

I. H_2S data as obtained by manual sampling and analysis at least one per day; or

II. H_2S data as obtained from the H_2S monitoring system for treated COG at least twice per day, at least 8 hours apart.

C. The alternative methods provided for in this condition shall only be used in the event of a malfunction or breakdown of the H_2S monitoring systems, i.e., not during periods when a monitoring system is functioning properly to collect valid data.

v. These H_2S monitors shall be tested at least every 12 months in accordance with 40 CFR 60, Appendix B, Performance Specification 7. The results of these tests shall be sent to the IEPA's Division of Air Pollution, Control Permit Section and Regional Office within 14 days after summarizing of results. In addition, the results shall be maintained in accordance with the recordkeeping specified in this permit. For the H_2S monitoring system for COG exiting the by-product plant, this testing shall be conducted as follows:

A. The H_2S content in grains per standard cubic foot of COG shall be determined using 40 CFR 60, Appendix A, Method 11 as adapted to measure higher ranges of H_2S.

B. The following revisions shall be made to Method 11 to allow the measuring of higher ranges of H_2S:

1. Diluent air shall mean air containing less than 0.5 ppm total sulfur compounds and less than 10 ppm each of moisture and hydrocarbons.

2. 7.0 Procedure - Located after the sampling valve, there will be a gas mixing box with a metered supply of (heated) diluent air. This metered supply of diluent air will be introduced prior to sampling and adjusted so that the final dilution of the sample will be 1:20 (i.e., 0.05 liters/min of sample to 0.95 liters/min of dilution air).

3. 9.4 - Vm = Volume of gas sample through the gas meter (meter conditions), liters/20.

Vm_{CSTD} = (Corrected) volume at standard conditions of gas sampled through the dry gas meter. (Standard Liters).

vi. In the event of malfunction or breakdown of the H2S monitoring systems, the Permittee shall repair and recalibrate the meter or monitoring systems as soon as practicable but no later than 10 days after the malfunction or breakdown is detected, unless prior Illinois EPA approval is obtained by submitting adequate justification to the Illinois EPA detailing the reasons for delay. Records of repair and recalibration must be maintained in accordance with the recordkeeping requirements of this permit. This condition does not relieve the Permittee of the minimum data collection requirements of this permit.

g. The Permittee shall equip the thermal oxidizer in the COG-DS with a continuous monitoring system, which shall be calibrated, maintained, and operated at all times the COG-DS thermal oxidizer is in operation, to monitor the combustion chamber temperature of the thermal oxidizer [Sections 39.5(7)(a) and (d) of the Act].

h. The Permittee shall sample and analyze the COG exiting the byproduct plant and treated COG from the COG-DS for PM content using appropriate ASTM methods or other comparable methodology. These measurements shall be conducted at least annually. The records for this activity shall also include data for the H_2S content of COG at the time of sampling [Sections 39.5.7(a) and (d) of the Act].

7.3.10 Recordkeeping Requirements

The Permittee shall maintain records of the following items for the affected by-product recovery plant, the COG-DS and COG flare, pursuant to Sections 39.5(7)(a) and (e) of the Act:

a. 40 CFR Part 61 Subpart L (40 CFR 61.138):

i. The following information pertaining to the design of control equipment installed to comply with 40 CFR 61.132 through 61.134 shall be recorded and kept in a readily accessible location:

A. Detailed schematics, design specifications, and piping and instrumentation diagrams.

B. The dates and descriptions of any changes in the design specifications.

ii. The following information pertaining to sources subject to 40 CFR 61.132 and sources subject to 40 CFR 61.133 shall be recorded and maintained for 2 years following each semiannual (and other) inspection and each annual maintenance inspection:

A. The date of the inspection and the name of the inspector.

B. A brief description of each visible defect in the source or control equipment and the method and date of repair of the defect.

C. The presence of a leak, as measured using the method described in 40 CFR 61.245(c). The record shall include the date of attempted and actual repair and method of repair of the leak.

D. A brief description of any system abnormalities found during the annual maintenance inspection, the repairs made, the date of attempted repair, and the date of actual repair.

b. 40 CFR Part 61 Subpart FF (40 CFR 61.356):

i. Each owner or operator of a facility subject to the provisions of Subpart FF shall comply with the recordkeeping requirements of 40 CFR 61.356. Each record shall be maintained in a readily accessible location at the facility site for a period not less than two years from the date the information is recorded unless otherwise specified [40 CFR 61.356(a)].

ii. Each owner or operator shall maintain records that identify each waste stream at the facility subject to Subpart FF, and indicate whether or not the waste stream is controlled for benzene emissions in accordance with this subpart. In addition the owner or operator shall maintain the following records [40 CFR 61.356(b)]:

A. For each waste stream not controlled for benzene emissions in accordance with Subpart FF, the records shall include all test results, measurements, calculations, and other documentation used to determine the following information for the waste stream: waste stream identification, water content, whether or not the waste stream is a process wastewater stream, annual waste quantity, range of benzene concentrations, annual average flow-weighted benzene concentration, and annual benzene quantity.

B. For each waste stream exempt from 40 CFR 61.342(c)(1) in accordance with 40 CFR 61.342(c)(3), the records shall include:

1. All measurements, calculations, and other documentation used to determine that the continuous flow of process wastewater is less than 0.02 liters (0.005 gallons) per minute or the annual waste quantity of process wastewater is less than 10 Mg/yr (11 ton/yr) in accordance with 40 CFR 61.342(c)(3)(i), or

2. All measurements, calculations, and other documentation used to determine that the sum of the total annual benzene quantity in all exempt waste streams does not exceed 2.0 Mg/yr (2.2 ton/yr) in accordance with 40 CFR 61.342(c)(3)(ii).

C. For each facility where process wastewater streams are controlled for benzene emissions in accordance with 40 CFR 61.342(d), the records shall include for each treated process wastewater stream all measurements, calculations, and other documentation used to determine the annual benzene quantity in the process wastewater stream exiting the treatment process.

D. For each facility where waste streams are controlled for benzene emissions in accordance with 40 CFR 61.342(e), the records shall include for each waste stream all measurements, including the locations of the measurements, calculations, and other documentation used to determine that the total benzene quantity does not exceed 6.0 Mg/yr (6.6 ton/yr).

E. For each facility where the annual waste quantity for process unit turnaround waste is determined in accordance with 40 CFR

61.355(b)(5), the records shall include all test results, measurements, calculations, and other documentation used to determine the following information: identification of each process unit at the facility that undergoes turnarounds, the date of the most recent turnaround for each process unit, identification of each process unit turnaround waste, the water content of each process unit turnaround waste, the annual waste quantity determined in accordance with 40 CFR 61.355(b)(5), the range of benzene concentrations in the waste, the annual average flow-weighted benzene concentration of the waste, and the annual benzene quantity calculated in accordance with 40 CFR 61.355(a)(1)(iii).

F. For each facility where wastewater streams are controlled for benzene emissions in accordance with 40 CFR 61.348(b)(2), the records shall include all measurements, calculations, and other documentation used to determine the annual benzene content of the waste streams and the total annual benzene quantity contained in all waste streams managed or treated in exempt waste management units.

iii. An owner or operator shall maintain a record for each visual inspection required by 40 CFR 61.343 through 61.347 that identifies a problem (such as a broken seal, gap or other problem) which could result in benzene emissions. The record shall include the date of the inspection, waste management unit and control equipment location where the problem is identified, a description of the problem, a description of the corrective action taken, and the date the corrective action was completed [40 CFR 61.356(g)].

c. 40 CFR Part 61 Subpart V (40 CFR 61.246):

i. A. Each owner or operator subject to the provisions of Subpart V shall comply with the recordkeeping requirements of 40 CFR 61.246 [40 CFR 61.246(a)(1)].

B. An owner or operator of more than one process unit subject to the provisions of Subpart V may comply with the recordkeeping requirements for these process units in one recordkeeping system if the system identifies each record by each process unit [40 CFR 61.246(a)(2)].

ii. When each leak is detected as specified in 40 CFR 61.242-2, 61.242-3, 61.242-7, 61.242-8, and 61.135,

the following requirements apply to the Permittee [40 CFR 61.246(b)]:

A. A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

B. The identification on a valve may be removed after it has been monitored for 2 successive months as specified in 40 CFR 61.242-7(c) and no leak has been detected during those 2 months.

C. The identification on equipment, except on a valve, may be removed after it has been repaired.

iii. When each leak is detected as specified in 40 CFR 61.242-2, 61.242-3, 61.242-7, 61.242-8, and 61.135, the following information shall be recorded by the Permittee in a log and shall be kept for 2 years in a readily accessible location [40 CFR 61.246(c)]:

A. The instrument and operator identification numbers and the equipment identification number.

B. The date the leak was detected and the dates of each attempt to repair the leak.

C. Repair methods applied in each attempt to repair the leak.

D. Above 10,000 if the maximum instrument reading measured by the methods specified in 40 CFR 61.245(a) after each repair attempt is equal to or greater than 10,000 ppm.

E. Repair delayed and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

F. The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

G. The expected date of successful repair of the leak if a leak is not repaired within 15 calendar days.

H. Dates of process unit shutdowns that occur while the equipment is unrepaired.

I. The date of successful repair of the leak.

iv. The following information pertaining to all equipment to which a standard applies shall be recorded in a log that is kept in a readily accessible location by the Permittee [40 CFR 61.246(e)]:

A. A list of identification numbers for equipment (except welded fittings) subject to the requirements of Subpart V.

B. 1. A list of identification numbers for equipment that the owner or operator elects to designate for no detectable emissions as indicated by an instrument reading of less than 500 ppm above background.

2. The designation of this equipment for no detectable emissions shall be signed by the owner or operator.

C. A list of equipment identification numbers for pressure relief devices required to comply with 40 CFR 61.242-4(a).

D. 1. The dates of each compliance test required in 40 CFR 61.242-2(e), 61.242-3(i), 61.242-4, 61.242-7(f), and 61.135(g).

2. The background level measured during each compliance test.

3. The maximum instrument reading measured at the equipment during each compliance test.

E. A list of identification numbers for equipment in vacuum service.

v. The following information pertaining to all valves subject to the requirements of 40 CFR 61.242-7(g) and (h) and to all pumps subject to the requirements of 40 CFR 61.242-2(g) shall be recorded by the Permittee in a log that is kept in a readily accessible location [40 CFR 61.246(f)]:

A. A list of identification numbers for valves and pumps that are designated as unsafe to monitor, an explanation for each valve or pump stating why the valve or pump is unsafe to monitor, and the plan for monitoring each valve or pump.

B. A list of identification numbers for valves that are designated as difficult to monitor, an explanation for each valve stating why the valve is difficult to monitor, and the planned schedule for monitoring each valve.

vi. The following information shall be recorded by the Permittee for valves complying with 40 CFR 61.243-2 [40 CFR 61.246(g)]:

A. A schedule of monitoring.

B. The percent of valves found leaking during each monitoring period.

vii. The following information shall be recorded in a log by the Permittee that is kept in a readily accessible location [40 CFR 61.246(h)]:

A. Design criterion required in 40 CFR 61.242-2(d)(5), 61.242-3(e)(2), and 61.135(e)(4) and an explanation of the design criterion; and

B. Any changes to this criterion and the reasons for the changes.

viii. The following information shall be recorded in a log by the Permittee that is kept in a readily accessible location for use in determining exemptions as provided in the applicability section of this subpart and other specific Subparts [40 CFR 61.246(i)]:

A. An analysis demonstrating the design capacity of the process unit, and

B. An analysis demonstrating that equipment is not in VHAP service.

ix. Information and data used to demonstrate that a piece of equipment is not in VHAP service shall be recorded in a log by the Permittee that is kept in a readily accessible location [40 CFR 61.246(j)].

d. The Permittee shall keep the following records for the COG flare [Section 39.5(7)(e) of the Act]:

i. Records of inspections and maintenance or repair activities conducted pursuant to Condition 7.3.9(e)(ii).

ii. H_2S content in the COG with supporting calculations of SO_2 emissions from the flare.

e. The following records for the COG-DS pursuant to Permit 06070022:

i. Temperature monitoring system for thermal oxidizer on the Claus Sulfur Recovery Unit:

A. Recorded data.

B. A log of operating time for the control system or devices, monitoring system, and the coke oven byproducts plant.

C. A maintenance log for the oxidizer and monitoring device detailing all routine and non-routine maintenance performed including dates and duration of any outages.

ii. Operating Records for the Packed Tower Amine Unit:

A. Amine temperature leaving the unit (°F).

B. Amine flow (gallons/minute).

C. COG flow into or out of the unit.

iii. Logs:

A. Operating logs.

B. Maintenance logs detailing all routine and non-routine maintenance performed including dates and duration of any outages.

iv. Production Records:

A. COG production during periods of time when the COG-DS is operating (mmscf/month and mmscf/year).

B. COG production during periods of time when the COG-DS is not operating (mmscf/month and mmscf/year).

v. Records of H_2S content in COG, with supporting data and calculations:

A. H_2S content of COG exiting the by-product plant, daily average.

B. H_2S content of COG, annual average.

C. H_2S content of treated COG, excluding outages, startup, shutdown, and upsets, monthly average.

vi. Emission Records for the COG Desulfurization System (Claus Sulfur Recovery Unit) [Sections 39.5.7(a) and (d) of the Act]

A. A file containing the emission factors used by the Permittee to determine emissions of PM_{10} and SO_2 from the Claus Sulfur Recovery Unit, with supporting documentation. These records shall be reviewed and updated by the Permittee as necessary to assure that the emission factors that it uses to determine emissions of this unit do not understate actual emissions. These records shall be prepared and copies sent to the Illinois EPA in accordance with Condition 5.9.6(c).

B. Engineering calculations for typical and maximum hourly PM_{10} and SO_2 emissions (lbs/hour) Claus Sulfur Recovery Unit, with supporting documentation.

C. Records for the concentration of SO_2 and H_2S (percent by volume) in the tail gas of the Claus Sulfur Recovery Unit, which is sent to the thermal oxidizer, as measured by process instrumentation.

D. Records for any periods of operation of the Claus Sulfur Recovery Unit that are not otherwise addressed in the required records during which the established emission factor in Condition 7.3.10(e)(vi)(A) would understate actual emissions of this unit, with description of the period of operation and an estimate of the additional emissions during such period that would not be accounted for by the established factor, with supporting explanation and calculations.

D. Records for any periods of operation of the Claus Sulfur Recovery Unit that are not otherwise addressed in the required records during which the established emission rate in Condition 7.3.10(e)(vi)(B) would understate the actual emissions of this unit, with description of the period of operation, including date, time and duration, explanation, and an estimate of the additional emissions during such period that would not be accounted for by the established rate, with supporting explanation and calculations.

F. Records for the annual PM_{10} and SO_2 emissions of the Claus Sulfur Recovery Unit for comparison to the limits in Conditions 7.3.7(e), with supporting calculations.

Note: Records for PM_{10} and SO_2 emissions associated with combustion of COG at the facility are contained in Condition 5.9.1(e).

f. The following records for the H_2S monitoring system for COG exiting the by-product plant, pursuant to FESOP 94120017:

i. The hourly average, 3-hour average and daily average H_2S content of the COG in grains per standard cubic foot.

ii. The H_2S monitor strip chart or disk storage.

iii. Thousand standard cubic feet of COG used per 3-hours for slab reheat furnaces 1-3 and ladle drying preheaters and per day for each unit operating group.

iv. The calibration, maintenance and repair of the H_2S monitor used in compliance calculations.

g. Other Records

i. Records of the amount of raw coke oven gas being received from the coke ovens (scf/mo and acf/yr).

ii. Records of the following by-products being produced:

A. Clean coke oven gas (scf/mo and scf/yr);

B. Light oil (gal/mo and gal/yr); and

C. Tar (ton/mo and ton/yr).

iii. If the Permittee operates under manufacturer's specifications or manufacturer's instructions, such manufacturer's documentation shall be kept at the source as part of the required records.

iv. Records of annual benzene waste generated on site (tons/yr).

v. Annual emissions of VOM from the affected by-product recovery plant.

h. Records for Malfunctions or Breakdowns

Pursuant to 35 IAC 201.263, the Permittee shall maintain records of continued operation of the affected COG flare as addressed by Condition 7.3.5 during malfunctions or breakdowns, which at a minimum, shall include the following records. The preparation of these records shall be completed within 45 days of an incident, unless the Permittee conducts a root cause analysis for the incident, in which case the preparation of these records, other than

the root cause analysis, shall be completed within 120 days of the incident.

i. Date, time and duration of the incident.

ii. A detailed description of the incident, including:

A. A chronology of significant events during and leading up to the incident.

B. Relevant operating data for the unit, including information such as operator log entries and directives provided by management during the incident.

C. The measures taken to reduce the quantity of emissions and the duration of the incident including the resources utilized to address the incident.

D. The magnitude of emissions during the incident.

iii. An explanation why continued operation of an affected COG flare was necessary to prevent personnel injury or prevent equipment damage.

iv. A discussion of the cause(s) or probable cause(s) of the incident including the following:

A. Whether the incident was sudden, unavoidable, or preventable, including:

1. Why the equipment design did not prevent the incident;

2. Why better maintenance could not have avoided the incident;

3. Why better operating practices could not have avoided the incident; and

4. Why there was no advance indication for the incident.

B. Whether the incident stemmed from any activity or event that could have been foreseen, avoided or planned for.

C. Whether the incident was or is part of a recurring pattern indicative of inadequate design, operation or maintenance.

v. A description of any steps taken or to be taken to prevent similar future incidents or reduce their frequency and severity.

vi. As an alternative to keeping the records required by Condition 7.3.10(h)(iv), the Permittee may perform a root cause analysis. For this purpose, a root cause analysis is an analysis whose purpose is to determine, correct and eliminate the primary causes of the incident and the excess emissions resulting there from. If the Permittee performs a root cause analysis method that would define the problem, define all causal relationships, provide a causal path to the root cause, delineate the evidence, and provide solutions to prevent a recurrence. Such an analysis shall be completed within one year of the incident.

7.3.11 Reporting Requirements

The Permittee shall submit the following reports pursuant to Section 39.5(7)(a) and (c) of the Act:

a. 40 CFR 61 Subpart L (40 CFR 61.138):

i. A report shall be submitted to the Illinois EPA semiannually starting 6 months after the initial reports required in 40 CFR 61.138(e) and 40 CFR 61.10, which includes the following information [40 CFR 61.138(f)]:

A. For sources subject to 40 CFR 61.132 and sources subject to 40 CFR 61.133:

1. A brief description of any visible defect in the source or ductwork;

2. The number of leaks detected and repaired; and

3. A brief description of any system abnormalities found during each annual maintenance inspection that occurred in the reporting period and the repairs made.

B. For equipment in benzene service subject to 40 CFR 61.135(a), information required by 40 CFR 61.247(b).

C. For each exhauster subject to 40 CFR 61.135 for each quarter during the semiannual reporting period:

1. The number of exhausters for which leaks were detected as described in 40 CFR 61.135(d) and (e)(5);

2. The number of exhausters for which leaks were repaired as required in 40 CFR 61.135(d) and (e)(6); and

3. The results of performance tests to determine compliance with 40 CFR 61.135(g) conducted within the semiannual reporting period.

D. A statement signed by the owner or operator stating whether all provisions of 40 CFR part 61, subpart L, have been fulfilled during the semiannual reporting period.

b. 40 CFR 61 Subpart V (40 CFR 61.247):

i. An owner or operator of any piece of equipment to which Subpart V applies shall submit a statement in writing notifying the Illinois EPA that the requirements of 40 CFR 61.242, 61.245, 61.246, and 61.247 are being implemented [40 CFR 61.247(a)(1)].

ii. A report shall be submitted to the Illinois EPA semiannually starting 6 months after the initial report required in 40 CFR 61.247(a), that includes the following information [40 CFR 61.247(b)]:

A. Process unit identification.

B. For each month during the semiannual reporting period:

1. Number of valves for which leaks were detected as described in 40 CFR 61.242-7(b) of 61.243-2.

2. Number of valves for which leaks were not repaired as required in 40 CFR 61.242-7(d).

3. Number of pumps for which leaks were detected as described in 40 CFR 61.242-2(b) and (d)(6).

4. Number of pumps for which leaks were not repaired as required in 40 CFR 61.242-2(c) and (d)(6).

5. Number of compressors for which leaks were detected as described in 40 CFR 61.242-3(f).

6. Number of compressors for which leaks were not repaired as required in 40 CFR 61.242-3(g).

7. The facts that explain any delay of repairs and, where appropriate, why a process unit shutdown was technically infeasible.

C. Dates of process unit shutdowns which occurred within the semiannual reporting period.

D. Revisions to items reported according to 40 CFR 61.247(a) if changes have occurred since the initial report or subsequent revisions to the initial report.

E. The results of all performance tests and monitoring to determine compliance with no detectable emissions and with 40 CFR 61.243-1 and 61.243-2 conducted within the semiannual reporting period.

c. 40 CFR 61 Subpart FF (40 CFR 61.357)

i. If the total annual benzene quantity from facility waste is less than 1 Mg/yr (1.1 ton/yr), then the owner or operator shall submit to the Illinois EPA and the Administrator a report that updates the information listed in 40 CFR 61.357(a)(1) through (a)(3) whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 1 Mg/yr (1.1 ton/yr) or more [40 CFR 61.357(b)].

ii. If the total annual benzene quantity from facility waste is less than 10 Mg/yr (11 ton/yr) but is equal to or greater than 1 Mg/yr (1.1 ton/yr) then the owner or operator shall submit to the Illinois EPA and the Administrator a report that updates the information listed in 40 CFR 61.357 (a)(1) through (a)(3). The report shall be submitted annually and whenever there is a change in the process generating the waste stream that could cause the total annual benzene quantity from facility waste to increase to 10 Mg/yr (11 ton/yr) or more. If the information in the annual report required by 40 CFR 61.357 (a)(1) through (a)(3) is not changed in the following year, the owner or operator may submit a statement to that effect [40 CFR 61.357(c)].

iii. If the total annual benzene quantity from facility waste is equal to or greater than 10 Mg/yr (11 ton/yr), then the owner or operator shall submit to the Illinois EPA and the Administrator reports described in 40 CFR 61.357(d) [40 CFR 61.357(d)].

d. i. Pursuant to Section 39.5(7)(f)(ii) of the Act, the Permittee shall promptly notify the Illinois EPA, Air Compliance Section, within 30 days of deviations by the affected coke by-product recovery plant, COG system and COG flare from applicable requirements, unless a NESHAP standard specifies a different timeframe, as follows:

A. Requirements in Condition 7.3.3(e), (f) and (g).

B. Requirements in Condition 7.3.6.

C. Requirements in Condition 7.3.7.

ii. All such deviations shall be summarized and reported as part of the semiannual monitoring report required by Condition 8.6.1.

iii. The Permittee shall notify the Illinois EPA, Air Compliance Section, of all other deviations as part of the semiannual monitoring reports required by Condition 8.6.1.

iv. All required deviation reports described in Condition 7.3.11(d) above shall contain the following information:

A. Date, time and duration of the deviation;

B. Description of the deviation;

C. Probable cause of the deviation; and

D. Any corrective action or preventive measures taken.

e. Reporting on the State malfunction and breakdown authorization shall be performed in accordance with Condition 5.10.5-2.

f. Reporting on the Federal SSM authorization shall be performed in accordance with Condition 5.10.5-3.

7.3.12 Operational Flexibility/Anticipated Operating Scenarios

The following requirements established by Construction Permit 09030019 shall be followed during idling of the affected coke batteries and coke by-product recovery plant:

This permit authorizes operation of adsorber systems to control emissions from the equipment in the Coke By-Product Recovery Plant, as an alternative to the various blanketing systems on the by-products plant during idling or other interruptions in

these blanketing systems, as addressed by Permit 09030019, subject to the following requirements:

a. Each system will use a canister-type vessel containing activated carbon to "filter" organic material from the exhaust from the units. The adsorber vessels will not be regenerated on-site but replaced when the capacity of the vessel to adsorb organic material is approached.

b. Various equipment or affected operations at the by-products plant, including processing vessels such as tar decanters, light oil decanters and storage tanks which are subject to NESHAP (the associated operations).

i. The affected adsorbers shall be designed and operated to achieve at least 98 percent control of emissions of benzene from the associated operations, as required by 40 CFR 61.139(a), with compliance determined in accordance with applicable requirements of 40 CFR 61.139(b) and (h).

ii. As the by-products plant is subject to 40 CFR 61, Subpart L, the Permittee will continue to be subject to applicable requirements of 40 CFR 61, Subpart A, General Provisions for associated operations, including 40 CFR 61.12(c), which requires that the Permittee maintain and operate these operations, including associated equipment for air pollution control, in a manner consistent with good air pollution control practice for minimizing emissions.

iii. A. The Permittee shall have access to sampling equipment and other capabilities necessary to conduct monitoring for the affected adsorbers, i.e., operational measurements for the concentration of benzene or hydrocarbons in the exhaust from the adsorbers.

B. While the adsorbers serve to control emissions from the associated operations, the Permittee shall conduct applicable monitoring for the affected adsorbers required by 40 CFR 61, Subparts A and L, including 40 CFR 61.139(e).

iv. For the associated operations while controlled by the adsorbers, the Permittee shall fulfill applicable recordkeeping requirements of 40 CFR 61, Subparts A and L, including 40 CFR 61.139(i).

v. The Permittee shall keep a file for each adsorber system that contains documentation for the adsorption capacity of the adsorption vessel and engineering calculations for the rate at which the associated operations would generate emissions and the expected operating life of an adsorption vessel in days.

vi. The operating records that the Permittee maintains for the associated operations and adsorbers shall include the following information, in addition to other required information:

A. The date that an adsorber vessel is switched out, with reason and measured hydrocarbon concentration in the exhaust prior to switchout.

B. For periods when the adsorbers operated properly, i.e., in accordance with Condition 7.3.12(a), relevant information to generally confirm proper operation.

C. For periods when an adsorber did not operate properly, identification of each such period and the associated operations that were operating, with detailed information describing: 1) The operation of the adsorber, including the monitored exhaust concentration; 2) The potential consequences for additional emissions of organic material with an estimate of the additional emissions, with explanation; 3) The actions taken to restore proper operation; and 4) Any actions taken to prevent similar events in the future.

vii. The maintenance records that the Permittee maintains for the associated operations and adsorbers shall include the following information, in addition to other required information:

A. Until the operations are idled, date and time that an inspection or maintenance/repair activity on the units was performed, with description of activity and name(s) of the responsible personnel.

B. While the associated operations are idled, date and time that an inspection or maintenance/repair activity for the preservation measures on the operations was performed, with description of activity and name(s) of the responsible personnel.

viii. The Permittee shall fulfill applicable reporting requirements of 40 CFR 61, Subparts A and L, for the associated operations while they are controlled by the affected adsorbers.

ix. The Permittee shall notify the Illinois EPA of the following events for the coke by-product plant:

A. The date that existing control systems for the plant are shut off, within 15 days of such date. This report shall describe any difficulties that were encountered in the transition to control with the affected adsorbers, confirm the integrity of the ductwork of each affected adsorber, and include the results of initial measurements for the hydrocarbon concentrations in the exhaust from each affected adsorber, conducted in accordance with Condition 7.3.12(a).

B. The date that operation of all adsorbers is no longer required by 40 CFR 61, Subpart L, within 30 days of such date. This report shall indicate the date when the emptying and cleaning of each group of the associated operations was completed, the current status of each affected adsorber (i.e., physically removed from the plant, scheduled to be removed, or left in place pending further developments), and the actions that are planned to maintain the condition and integrity of the affected associated operations while they are idle.

Note: During a period when the affected plant is idle, even if all associated operations are cleaned and emptied, the Permittee must continue to submit the routine semiannual compliance reports required by 40 CFR 61, Subpart L.

C. The date that resumption of normal operation of the by-product plant is planned, at least 10 days prior to such date. This report shall generally describe the sequence of events that will accompany resumption of operation of the existing control systems for the plant.

7.3.13 Compliance Procedures

For the affected coke by-product recovery plant, COG system and COG flare, compliance with Conditions 7.3.3 and 7.3.7 is addressed by the work practices, testing, monitoring, recordkeeping and reporting requirements in Section 7.3 of this permit.

7.3.14 State-Only Conditions

State-only conditions are not being established.

7.4 Blast Furnaces

7.4.1 Description

Blast Furnaces and Casthouse:

Iron ore is converted to molten iron in the "A" and "B" Blast Furnaces. Iron ore, coke and a variety of fluxes (collectively called the burden) are charged into the top of the furnace, while heated air is blown up through the burden at a high velocity. Molten iron and slag accumulate in the bottom of the furnace, where a taphole is periodically drilled. The molten iron and slag pour out of the furnace into a trough, where the slag is separated from the iron. The iron moves down runners until it pours into torpedo cars. From here, the iron is taken to the Basic Oxygen Furnace (BOF) shop, where it is converted into steel. The slag travels down a separate runner and dumps into the slag pits. The molten slag is quenched with a mixture of water and potassium permanganate solution.

Charging of the Blast Furnace generates particulate matter emissions. Each furnace has a double-bell system to minimize emissions from charging.

Casthouse emissions consisting of particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, and organic materials are generated during tapping of the furnace and the miscellaneous operations that take place within the casthouse structure. Emissions are controlled by the Casthouse Baghouse and the Iron Spout Baghouse.

Emissions may also be discharged from a blast furnace during startup, malfunctions and shutdowns for routine maintenance. Each furnace is equipped with bleeder valves which will relieve to the atmosphere if the furnace becomes over pressurized. This can occur during furnace slops when material in the furnace bridges forming a void and then collapses. Slips can cause over pressurization. In this condition, the stock in the furnace will bridge and cause a void to develop. The void will increase until the bridge collapses. Backdrafting of the blast furnaces is conducted to perform certain repairs, both routine and non-routine. Steam is utilized to draw furnace gases back through the tuyeres and out of backdraft stacks.

Blast Air Stoves:

The blast air stoves heat the blast air for the blast furnaces. Emissions from the stoves consist of particulate matter, sulfur dioxide, nitrogen oxides, and carbon monoxide generated as by-products of the combustion of Blast Furnace Gas (BFG) and Coke Oven Gas (COG). In addition, the blast furnaces can also use fuel oil in the event that other fuels are not available.

The byproduct gases from the blast furnaces are first cleaned in a BFG Pretreatment system with mechanical separation and water

wash to remove entrained dust and are then combusted in the stoves for the blast furnaces and other units at the source. BFG is primarily made up of carbon monoxide. The heat generated by the combustion of these gases is used to heat the brick inside of the stoves. The air flow is switched and this stored heat is then transferred to the blast air that is blown into the blast furnaces as part of the iron making process. There are three stoves for each furnace, which enables a continuous supply of blast air to the blast furnace. Only two of the three stoves will burn at any given time. All three stoves are exhausted to a common stack.

Excess BFG is also used in the various other fuel combustion emission units at the source. BFG that cannot be used as fuel is flared in either BFG flare #1 or #2.

Note: This narrative description is for informational purposes only and is not enforceable.

7.4.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Date Constructed	Emission Control Equipment
Blast Furnaces	• Blast Furnaces (A and B including charging and BFG pretreatment system)	Before 1972	None
	• Blast Furnace Casthouse (Tapping, Iron and Slag Runner, Slag Pits and Torpedo Car Loading Emissions From A and B Furnaces)		Casthouse Baghouse; and Iron Spout Baghouse;
	• Blast Furnace Gas Flare #1		None
	• (6) Blast Air Stoves (BFG,COG and natural Gas) (3 per each furnace)	Before 1972	None
	• Blast Furnace Gas Flare #2	2008	None
	• Slag pits	Before 1972	None

7.4.3 Applicable Provisions

a. The "affected blast furnace processes" for the purpose of these unit-specific conditions, are the emission units and activities described in Conditions 7.4.1 and 7.4.2.

b. Pursuant to 35 IAC 212.445, emissions of PM shall not exceed the following limits:

i. Uncaptured particulate matter from any opening in a blast furnace cast house shall not exceed 20 percent opacity on a six (6) minute rolling average basis beginning from initiation of the opening of the tap hole up to the point where the iron and slag stops flowing in the trough. Opacity observations shall be taken in accordance with the procedures of 40 CFR 60, Appendix A, Method 9 [35 IAC 212.445(a)].

ii. A. Particulate matter emissions from control equipment used to collect any of the emissions from the tap hole, trough, iron or slag runners or iron or slag spouts shall not exceed 0.023 g/dscm (0.010 gr/dscf). Compliance with this standard shall be determined in accordance with the procedures set out in 40 CFR 60, Appendix A, Methods 1 through 5, incorporated by reference in 35 IAC 212.113 and shall be based on the duration of a cast. For this purpose, a cast is defined as the initiation of the opening of the tap hole up to the point where the iron and slag stop flowing through the trough consistent with 35 IAC 212.445(a)(i) [35 IAC 212.445(b)(1)].

B. The opacity of emissions from control equipment used to collect any of the particulate matter emissions from the tap hole, trough, iron or slag runners or iron or slag spouts shall not exceed 10 percent on a six (6) minute rolling average basis [35 IAC 212.445(b)(2)].

c. Pursuant to 35 IAC 214.301, the affected blast furnace processes shall comply with the following: no person shall cause or allow the emission of sulfur dioxide into the atmosphere from any process emission source to exceed 2000 ppm.

d. The affected blast furnace processes other than the cast house are subject to 35 IAC 212.123(a), which provides that no person shall cause or allow the emission of smoke or other particulate matter, with an opacity greater than 30 percent, into the atmosphere from any emission unit other than those emission units subject to the requirements of 35 IAC 212.122, except as allowed by 35 IAC 212.123(b) and 212.124.

e. Pursuant to 40 CFR 63.7790(a) and Paragraph 7 of Table 1, of 40 CFR 63 Subpart FFFFF, the emissions shall not exceed the following limits from each casthouse at an existing blast furnace:

i. Particulate matter emissions from a control device shall not exceed 0.01 gr/dscf; and

ii. Any secondary emissions that exit any opening in the casthouse or structure housing the blast furnace shall not exceed opacity greater than 20 percent (6 minute average).

f. Pursuant to 40 CFR 63.7790(b)(1), the Permittee must operate each capture system applied to emissions from blast furnace casthouse at or above the lowest value or settings established for the operating limits in the Permittee's operation and maintenance plan.

g. Pursuant to 35 IAC 212.316(f), uncaptured particulate matter emissions from blast furnace charging shall not exceed opacity of 20 percent.

h. Pursuant to 35 IAC 212.458(b)(7) and (c), blast furnace stoves shall comply with the following: No person shall cause or allow emissions of PM_{10} into the atmosphere to exceed 22.9 mg/scm (0.01 gr/scf) during any one hour period, provided that this limit shall not apply if there are no visible emissions, except if a stack test is performed, the absence of visible emissions is not a defense to a finding violation.

7.4.4 Non-Applicability of Regulations of Concern

a. The emission limitations of 35 IAC 212.324 are not applicable to any affected blast furnace processes that are subject to a specific emissions standard or limitation contained in 35 IAC Part 212 Subpart R, Primary and Fabricated Metal Products and Machinery Manufacture, pursuant to 35 IAC 212.324 (a)(3).

b. The affected blast furnace processes are not subject to 35 IAC 212.321 and 35 IAC 212.322, pursuant 35 IAC 212.441, which provides that, except where noted, 35 IAC 212.321 and 212.322 shall not apply to the steel manufacturing processes subject to 35 IAC 212.442 through 35 IAC 212.452.

c. This permit is issued based on the affected blast furnace processes not being subject to the applicable requirements of 35 IAC 219.301 because the affected processes do not emit photochemically reactive organic material as defined in 35 IAC 211.4690.

d. The affected blast furnace processes are not subject to 35 IAC 216.121 because the affected blast furnace processes are not the fuel combustion emission sources, as defined 35 IAC 211.2470.

e. Pursuant to 40 CFR 63.7491(g), the Blast Furnace Stoves are not subject to any applicable requirements in 40 CFR Part

63, Subpart DDDDD, NESHAP: Industrial, Commercial, and Institutional Boilers and Process Heaters.

7.4.5-1 Work Practices: Operation and Maintenance Plan (40 CFR 63.7800)

a. As required by 40 CFR 63.6(e)(1)(i), the Permittee shall always operate and maintain the affected blast furnace processes that are subject 40 CFR 63 Subpart FFFFF, including air pollution control and monitoring equipment, in a manner consistent with good air pollution control practices for minimizing emissions at least to the levels required by 40 CFR 63 Subpart FFFFF.

b. The Permittee shall prepare and operate at all times each capture system or control device according to a written operation and maintenance plan for affected blast furnace casthouse. Each written operation and maintenance plan shall address the following elements:

i. Monthly inspections of the equipment that is important to the performance of the total capture system (*e.g.*, pressure sensors, dampers, and damper switches). This inspection must include observations of the physical appearance of the equipment (*e.g.*, presence of holes in ductwork or hoods, flow constrictions caused by dents or accumulated dust in the ductwork, and fan erosion). The operation and maintenance plan also must include requirements to repair any defect or deficiency in the capture system before the next scheduled inspection.

ii. Preventative maintenance for each control device, including a preventative maintenance schedule that is consistent with the manufacturer's instructions for routine and long-term maintenance.

iii. Operating limits for each capture system applied to emissions from a blast furnace casthouse. The Permittee shall establish the operating limits according to the following requirements in 40 CFR 63.7800(b)(3)(i) through (iii):

A. Select operating limit parameters appropriate for the capture system design that are representative and reliable indicators of the performance of the capture system. At a minimum, the Permittee shall use appropriate operating limit parameters that indicate the level of the ventilation draft and the damper position settings for the capture system when operating to collect emissions, including revised settings for seasonal variations.

Appropriate operating limit parameters for ventilation draft include, but are not limited to, volumetric flow rate through each separately ducted hood, total volumetric flow rate at the inlet to the control device to which the capture system is vented, fan motor amperage, or static pressure.

B. For each operating limit parameter selected as described above, the Permittee shall designate the value or setting for the parameter at which the capture system operates during the process operation. If the operation allows for more than one process to be operating simultaneously, the Permittee shall designate the value or setting for the parameter at which the capture system operates during each possible configuration that the source may operate.

C. Include documentation in the plan to support selection of the operating limits established for the capture system. This documentation must include a description of the capture system design, a description of the capture system operating during production, a description of each selected operating limit parameter, a rationale for why the Permittee chose the parameter, a description of the method used to monitor the parameter according to the requirements of 40 CFR 63.7830(a), and the data used to set the value or setting for the parameter for each process configurations.

iv. Pursuant to 40 CFR 63.7800(b)(4), corrective action procedures for baghouses equipped with bag leak detection systems. In the event a bag leak detection system alarm is triggered, the Permittee shall initiate corrective action to determine the cause of the alarm within 1 hour of the alarm, initiate corrective action to correct the cause of the problem within 24 hours of the alarm, and complete the corrective action. Corrective actions may include, but are not limited to:

A. Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in emissions [40 CFR 63.7800(b)(4)(i)].

B. Sealing off defective bags or filter media [40 CFR 63.7800(b)(4)(ii)].

C. Replacing defective bags or filter media or otherwise repairing the control device [40 CFR 63.7800(b)(4)(iii)].

D. Sealing off a defective baghouse compartment [40 CFR 63.7800(b)(4)(iv)].

E. Cleaning the bag leak detection system probe, or otherwise repair the bag leak detection system [40 CFR 63.7800(b)(4)(v)].

F. Shutting down the process producing the particulate emissions [40 CFR 63.7800(b)(4)(vi)].

7.4.5-2 Work Practices: Startup, Shutdown and Malfunction

a. Provisions Related to 40 CFR 63, Subpart FFFFF

i. Pursuant to 40 CFR 63.7810, the Permittee must be in compliance with the emission limitations and operation and maintenance requirements in 40 CFR 63 Subpart FFFFF at all times, except during periods of startup, shutdown and malfunction as defined in 40 CFR 63.2

ii. Pursuant to 40 CFR 63.7810(c), the Permittee shall develop a written startup, shutdown, and malfunction plan for the affected blast furnaces and casthouses according to the provisions established in 40 CFR 63.6(e)(3).

iii. Pursuant to 40 CFR 63.7835, consistent with 40 CFR 63.6(e) and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if the Permittee demonstrates that it was operating in accordance with 40 CFR 63.6(e)(1).

iv. The Permittee shall fulfill the applicable reporting requirements identified in 40 CFR 63.10(d) (Condition 5.10.5(b)) and 40 CFR 63.7841(b)(4).

v. The Permittee shall keep records in accordance with 40 CFR 63.7842(a)(2) related to startup, shutdown and malfunction.

b. Startup and Malfunction/Breakdown Authorizations

i. Malfunction and Breakdown, pursuant to 201.149 and Part 201, Subpart I

A. Subject to the following terms and conditions, the Permittee is authorized to continue operation of the affected blast furnace processes in excess of the applicable state standards in 35 IAC 212.445(b)(1) in the event of a malfunction or breakdown. This shall include blast furnace over pressurization, slips, use of auxiliary tap-holes, and back-drafting associated with periods of malfunction and breakdown.

Note: This authorization is provided because the Permittee applied for such authorization in its CAAPP application, generally explaining why such continued operation would be required to prevent injury to personnel or severe damage to equipment, and describing the measures that will be taken to minimize emissions from any malfunctions and breakdowns.

B. This authorization only allows such continued operation as necessary to prevent injury to personnel or severe damage to equipment and does not extend to continued operation solely for the economic benefit of the Permittee.

C. Upon occurrence of excess emissions due to malfunction or breakdown, the Permittee shall repair the affected emission/process units and/or re-establish applicable control practices.

D. The Permittee shall fulfill the applicable recordkeeping and reporting requirements of Conditions 7.4.9(e) and 5.10.5-2, respectively. For these purposes, time shall be measured from the start of a particular incident. The absence of excess emissions for a short period shall not be considered to end the incident if excess emissions resume.

E. Following notification to the Illinois EPA (see Condition 5.10.5-2(a)(ii))of a malfunction or breakdown with excess emissions, the Permittee shall comply with all reasonable directives of the Illinois EPA with respect to such incident.

F. This authorization does not relieve the Permittee from the continuing obligation to minimize excess emissions during malfunction or breakdown. As provided by 35 IAC 201.265, an authorization in a permit for continued operation with excess emissions during malfunction and breakdown does not shield the

Permittee from enforcement for any such violation and only constitutes a prima facie defense to such an enforcement action provided that the Permittee has fully complied with all terms and conditions connected with such authorization.

ii. Startup, pursuant to 35 IAC 201.149 and Part 201, Subpart I

A. Subject to the following terms and conditions, for the affected blast furnace, the Permittee is authorized to violate the applicable standards of 35 IAC 212.445(b)(1), 212.445(b)(2) and 35 IAC 214.301 during startup.

Note: This authorization is provided because the Permittee applied for such authorization in its CAAPP application, generally describing the efforts that will be used "…to minimize startup emissions, duration of individual starts, and frequency of startups".

B. This authorization does not relieve the Permittee from the continuing obligation to demonstrate that all reasonable efforts are made to minimize startup emissions, duration of individual startups and frequency of startups.

C. The Permittee shall follow the written startup, shutdown, and malfunction plan for the affected blast furnace processes prepared pursuant to 40 CFR 63.6(e)(3) and Condition 7.4.5-2. In addition, the Permittee shall also review the operating condition of the affected blast furnace process prior to initiating startup.

D. The Permittee shall fulfill applicable recordkeeping requirements of Condition 7.4.9(d).

E. The Permittee shall fulfill applicable reporting requirements of Condition 5.10.5-1.

F. As provided by 35 IAC 201.265, an authorization in a permit for excess emissions during startup does not shield a Permittee from enforcement for any violation of applicable emission standard(s) that occurs during startup and only constitutes a prima facie defense to such an enforcement action provided that the Permittee has fully complied with all terms and conditions connected with such authorization.

7.4.5-3 Work Practices from State Permits

a. Except during periods of runner maintenance, the hot metal runners and the short slag runner shall be covered with permanent type runner covers [72080034, 72080036, T1].

b. Water spraying of the slag for the purpose of cooling and minimizing slag load-out emissions will take place after completion of the slagging operation and prior to slag-loadout [85030039, T1].

c. BFG flare #1 shall be operated with no visible emissions as determined by USEPA Method 22, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours [0607023, T1].

d. Requirements for BFG Flare #2 from Permit 06070023:

i. BFG flare #2 shall be operated to comply with the following equipment work practices [T1]:

A. BFG flare #2 shall be operated with no visible emissions as determined by the methods specified in 40 CFR 60.18(f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

B. BFG flare #2 shall be operated with a flame present at all times.

ii. Emissions of PM and PM_{10} from BFG flare #2 shall be controlled by the existing BFG pretreatment system, which entails treatment by dust catchers and wet scrubbers [T1].

iii. BFG and natural gas shall be the only fuels combusted in BFG flare #2 [T1].

7.4.5-4 Other Work Practices

The following requirements are established pursuant to Section 39.5(7)(a) of the Act:

a. The Permittee shall maintain the double-bell system of the blast furnaces in order to minimize emissions from furnace charging.

b. The Permittee shall develop and implement operating practices plan for slag handling processing associated with the slag pits for minimizing emissions and keeping them below the levels established in Condition 7.4.6(e).

7.4.6 Production and Emission Limitations from Existing Permits

a. i. Total combined production of hot metal (a.k.a., iron) from blast furnaces A and B shall not exceed 9,849 net tons per day, averaged over any calendar month [72080034,7208036,95010001, T1]; and

ii. Maximum amount of pellets charged shall not exceed 4,308,581 tons/yr [95010001, T1].

b. Casthouse Baghouse emissions shall not exceed the following limits [95010001, T1]:

Pollutant	Emission Factors (Lbs/Ton Iron)	Maximum Emissions (Tons/Yr)
PM	0.0703	111.19
PM_{10}	0.0703	111.19
SO_2	0.2006	422.00
NO_x	0.0144	22.79
VOM	0.0946	149.68

c. Blast Furnace uncaptured fugitives emissions shall not exceed the following limits [95010001, T1]:

Pollutant	Emission Factors (Lbs/Ton Iron)	Maximum Emissions (Tons/Yr)
PM	0.031	49.06
PM_{10}	0.0155	24.53
SO_2	0.0104	21.94
NO_x	0.0007	1.14
VOM	0.0047	7.42

d. Blast Furnace Charging emissions shall not exceed the following limits [95010001, T1]:

Pollutant	Emission Factors (Lbs/Ton Pellets)	Maximum Emissions (Tons/Yr)
PM	0.0024	5.17
PM_{10}	0.0024	5.17

e. Slag Pits emissions shall not exceed the following limits [95010001, T1]:

Pollutant	Emission Factors (Lbs/Ton Iron)	Maximum Emissions (Tons/Yr)
PM	0.00417	6.60
PM_{10}	0.00417	6.60
SO_2	0.0100	15.83

f. Iron Spout Baghouse emissions shall not exceed the following limits [95010001, T1]:

Pollutant	Emission Factors (Lbs/Ton Iron)	Maximum Emissions (Tons/Yr)
PM	0.02548	40.32
PM_{10}	0.02548	40.32
SO_2	0.0073	13.89

g. Total emissions from blast furnace operations shall not exceed the following limits, tons/yr [95010001, T1]:

	PM*	PM_{10}*	SO_2	NO_x	VOM
Blast Furnace Operations	212	188	474	24	157

* Limit does not address the iron pellet screen (See Section 7.1)

h. Compliance with the daily limit of Condition 7.4.6(a)(i) shall be determined from a monthly total of the relevant daily data divided by the number of days in the month [95010001].

i. Compliance with the annual limits of Condition 7.4.6(a)(2) and Conditions 7.4.6(b) through (g) shall be determined based on a calendar year [95010001].

j. Overlapping casting of "A" and "B" Blast Furnaces shall not exceed a casting rate of 6 tons per minute per furnace [72080034 and 7208036, T1].

k. The PM content of the BFG burned at the facility shall not exceed 0.01 grains/dscf [06070023, T1].

7.4.7 Testing Requirements

a. Blast furnace casthouse pursuant to NESHAP.

The Permittee shall comply with the following testing requirements pursuant to 40 CFR Part 63 Subpart FFFFF:

i. Pursuant to 40 CFR 63.7821(c), for each emissions unit equipped with a baghouse, the Permittee must conduct performance tests no less frequently than once every five years.

ii. Test methods for compliance demonstration with the emission limits for particulate matter [40 CFR 63.7822(b)]:

A. Determine the concentration of particulate matter according to the following test methods in Appendix A to 40 CFR Part 60.

1. Method 1 to select sampling port locations and the number of traverse points. Sampling sites must be located at the outlet of the control device and prior to any releases to the atmosphere.

2. Method 2, 2F, or 2G to determine the volumetric flow rate of the stack gas.

3. Method 3, 3A, or 3B to determine the dry molecular weight of the stack gas.

4. Method 4 to determine the moisture content of the stack gas.

5. Method 5, 5D, or 17, as applicable, to determine the concentration of particulate matter (front half filterable catch only).

B. Collect a minimum sample volume of 60 dry standard cubic feet (dscf) of gas during each particulate matter test run. Three valid test runs are needed to comprise a performance test.

iii. Test methods for compliance demonstration with the opacity limits [40 CFR 63.7823(b) and (c)]:

A. The Permittee shall conduct each visible emissions performance test such that the opacity observations overlap with the performance test for particulate matter [40 CFR 63.7823(b)].

B. To determine compliance with the applicable opacity limit for a blast furnace casthouse, the Permittee shall:

1. Use a certified observer to determine the opacity of emissions according to Method 9 in Appendix A to 40 CFR Part 60.

2. Obtain a minimum of 30 6-minute block averages. For a blast furnace casthouse, the Permittee shall make observations during tapping of the furnace. Tapping begins when the furnace is opened, usually by creating a hole near the

bottom of the furnace, and ends when the hole is plugged.

b. Blast furnace casthouse.

The Permittee shall comply with the following testing requirements pursuant to Sections 39.5(7)(d) and (p) of the Act:

i. For uncaptured emissions (roof monitor) or secondary emissions:

A. The Permittee shall have the opacity (6-minute average), of the exhaust of the building housing the blast furnace casthouse determined by a qualified observer in accordance with USEPA Method 9 while the affected blast furnace(s) are being tapped, as further specified below.

B. The duration of opacity observations for each test shall be at least 30 minutes unless no visible emissions are observed as determined by USEPA Method 22 or the average opacities for the first 12 minutes of observations conducted for the point of release that displays the greatest opacity, 6-minute average, are both no more than 10.0 percent.

C. 1. Observations of opacity shall be conducted on the following frequency unless absence of adequate daylight or weather conditions preclude scheduled observation, in which case, the next observations shall be conducted on the next day during which observations of opacity can properly be conducted in accordance with USEPA Method 9:

I. On a weekly basis (at least once every 7 operating days of the casthouse) except as provided below.

II. On a daily basis (at least 5 days out of 7 operating days of the casthouse) if the maximum opacity observed during any of the five previous observations was 18 percent or more, 6-minute average, continuing on a daily basis until the maximum opacities measured in five consecutive daily observations are all less than 18 percent, 6-minute average, at which time

observations on a weekly basis shall resume.

2. Upon written request by the Illinois EPA, additional opacity observations shall be conducted within five operating days for the casthouse from the date of the request by the Illinois EPA or on the date agreed upon by the Illinois EPA, whichever is later. For such observations conducted pursuant to a request from the Illinois EPA:

I. The Permittee shall notify the Illinois EPA at least 24 hours in advance of the date and time of these observations, in order to enable the Illinois EPA to witness the observations. This notification shall include the name and employer of the qualified observer(s).

II. The Permittee shall promptly notify the Illinois EPA of any changes in the time or date for observations.

III. The duration of these observations shall cover a complete heat or cycle of the affected blast furnace.

IV. The Permittee shall provide a copy of the current certification for the opacity observer and observer's readings to the Illinois EPA at the time of the observations, if the Illinois EPA personnel are present.

D. The Permittee shall keep records for all opacity measurements for the casthouse made in accordance with USEPA Method 9 that the Permittee conducts or that are conducted at its behest by individuals who are qualified to make such observations. For each occasion on which such measurements are made, these records shall include the formal report for the measurements if conducted pursuant to Condition 7.4.7(b)(i)(2), or otherwise the identity of the observer, a description of the measurements that were made, the operating condition of the casthouse, the observed opacity, and copies of the raw data sheets for the measurements.

ii. Emissions from control equipment [35 IAC 212.445(b)]:

A. Upon request from the Illinois EPA, compliance with emission limits of 35 IAC 212.445(b)(1)(see also Condition 7.4.3(b)(ii)(A)) shall be determined in accordance with the procedures set out in 40 CFR Part 60, Appendix A, Methods 1 through 5, incorporated by reference in 35 IAC 212.113, and shall be based on the arithmetic average of three runs. Calculations shall be based on the duration of a cast defined in 35 IAC 212.445(a)(1).

B. Upon request from the Illinois EPA, opacity readings, for verifying compliance with emission limit of 35 IAC 212.445(b)(2)(see also Condition 7.4.3(b)(ii)(B)), shall be taken in accordance with the observation procedures set out in 40 CFR part 60, Appendix A, Method 9, incorporated by reference in 35 IAC 212.113.

c. Additional Emission Testing for the Casthouse Baghouse and the Iron Spout Baghouse, pursuant to Sections 39.5(7)(d) and (p) of the Act:

i. As part of the emission testing required by Condition 7.4.7(a), the Permittee shall also measure the SO_2, NO_x and VOM emissions from each baghouse.

ii. The following USEPA Test Methods shall be used for testing of emissions, unless another USEPA Test Method is approved by the Illinois EPA.

Location of Sample Points	Method 1
Gas Flow and Velocity	Method 2
Flue Gas Weight	Method 3
Moisture	Method 4
SO_2	Method 6
NO_x	Method 7
VOM	Method 25

iii. For this emission testing, test notification and reporting shall be done by the Permittee in accordance with Conditions 8.6.2 and 8.6.3 of this permit.

d. BFG Flares:

Pursuant to Sections 39.5(7)(d) and (p) of the Act, the Permittee shall conduct observations for each BFG flare for the presence of visible emissions and/or opacity, using USEPA Method 22 and 9, respectively. These observations shall be conducted on at least a monthly basis for each

flare. In addition, observations shall be coordinated with weather conditions so that at least two observations are made in each calendar year during elevated wind speed conditions, i.e., wind speed of at least 16 miles per hour. These observations shall be conducted by individual(s) certified to observe opacity by USEPA Method 9. The observer(s) shall initially conduct observations for visible emissions. If any visible emissions are observed, the observations shall continue for two hours or until the cumulative duration of visible emissions exceeds ten minutes, whichever occurs first. If any visible emissions are observed, observations for opacity shall also be conducted.

7.4.8 Monitoring Requirements

a. Monitoring requirements pursuant to 40 CFR 63.7830(a)

For each capture system subject to an operating limit in 40 CFR 63.7790(b)(1) established in the Permittee's capture system operation and maintenance plan, the Permittee must install, operate, and maintain a CPMS according to the following requirements:

Dampers that are manually set and remain in the same position are exempt from the requirement to install and operate a CPMS. If dampers are not manually set and remain in the same position, the Permittee shall make a visual check at least once every 24 hours to verify that each damper for the capture system is in the same position as during the initial performance test.

b. Monitoring requirements pursuant to 40 CFR 7830(b)(1)

The casthouse baghouse and iron spout baghouse shall each be equipped with a bag leak detection system which the Permittee shall operate and maintain according to the following requirements of 40 CFR 63.7831(f):

i. The system must be certified by the manufacturer to be capable of detecting emissions of particulate matter at concentrations of 10 milligrams per actual cubic meter (0.0044 grains per actual cubic foot) or less [40 CFR 63.7831(f)(1)].

ii. The system must provide output of relative changes in particulate matter loadings [40 CFR 63.7831(f)(2)].

iii. The system must be equipped with an alarm that will sound when an increase in relative particulate loadings is detected over a preset level. The alarm must be located such that it can be heard by the appropriate plant personnel [40 CFR 63.7831(f)(3)].

iv. Each system that works based on the triboelectric effect must be installed, operated, and maintained in a manner consistent with the guidance document, "Fabric Filter Bag Leak Detection Guidance," EPA-454/R-98-015, September 1997 [40 CFR 63.7831(f)(4)].

v. Following the initial adjustment, do not adjust the sensitivity or range, averaging period, alarm set points, or alarm delay time, except as detailed in your operation and maintenance plan. Do not increase the sensitivity by more than 100 percent or decrease the sensitivity by more than 50 percent over a 365-day period unless a responsible official certifies, in writing, that the baghouse has been inspected and found to be in good operating condition [40 CFR 63.7831(f)(6)].

c. The Permittee shall conduct inspections of each baghouse at the specified frequencies according to the following requirements [40 CFR 63.7830(b)(4)]:

i. Monitor the pressure drop across each baghouse cell each day to ensure pressure drop is within the normal operating range identified in the operation and maintenance plan manual.

ii. Confirm that dust is being removed from hoppers through weekly visual inspections or other means of ensuring the proper functioning of removal mechanisms.

iii. Check the compressed air supply for pulse-jet baghouses each day.

iv. Monitor cleaning cycles to ensure proper operation using an appropriate methodology.

v. Check bag cleaning mechanisms for proper functioning through monthly visual inspection or equivalent means.

vi. Make monthly visual checks of bag tension on reverse air and shaker-type baghouses to ensure that bags are not kinked (kneed or bent) or laying on their sides. You do not have to make this check for shaker-type baghouses using self-tensioning (spring-loaded) devices.

vii. Confirm the physical integrity of the baghouse through quarterly visual inspections of the baghouse interior for air leaks.

viii. Inspect fans for wear, material buildup, and corrosion through quarterly visual inspections, vibration detectors, or equivalent means.

d. Site-specific monitoring plan requirements pursuant to 40 CFR 63.7831(a)

For each CPMS required in 40 CFR 63.7830, the Permittee shall develop and make available for inspection upon request by the Illinois EPA a site-specific monitoring plan that addresses the following requirements of 40 CFR 63.7831(a)(1) through (a)(6), including:

i. Installation of the CPMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.*, on or downstream of the last control device) [40 CFR 63.7831(a)(1)];

ii. Performance and equipment specifications for the sample interface, the parametric signal analyzer, and the data collection and reduction system [40 CFR 63.7831(a)(2);

iii. Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations) [40 CFR 63.7831(a)(3);

iv. Ongoing operation and maintenance procedures in accordance with the general requirements of 40 CFR 63.8(c)(1), (c)(3), (c)(4)(ii), (c)(7), and (c)(8) [40 CFR 63.7831(a)(4);

v. Ongoing data quality assurance procedures in accordance with the general requirements of 40 CFR 63.8(d) [40 CFR 63.7831(a)(5); and

vi. Ongoing recordkeeping and reporting procedures in accordance with the general requirements of 40 CFR 63.10(c), (e)(1), and (e)(2)(i) [40 CFR 63.7831(a)(6).

e. Pursuant to 40 CFR 63.7831(b), unless otherwise specified by the NESHAP, each CPMS must:

i. Complete a minimum of one cycle of operation for each successive 15-minute period and collect a minimum of three of the required four data points to constitute a valid hour of data;

ii. Provide valid hourly data for at least 95 percent of every averaging period; and

iii. Determine and record the hourly average of all recorded readings.

f. Pursuant to 40 CFR 63.7831(c), the Permittee shall conduct a performance evaluation of each CPMS in accordance with the site-specific monitoring plan.

g. Pursuant to 40 CFR 63.7831(d), the Permittee shall operate and maintain the CPMS in continuous operation according to the site-specific monitoring plan.

h. Pursuant to 40 CFR 63.7790(b)(1) and 63.7800(b)(3)(i), the Permittee shall operate each capture system applied to emissions from a blast furnace casthouse at or above the lowest value or settings as established in the Permittee's operation and maintenance plan and which are currently as follows:

i. Casthouse Baghouse:

A. Motor amperage (total), both blast furnaces casting: 245 amps

B. Motor amperage, one blast furnace casting: 125 amps

ii. Iron Spout Baghouse:

A. Motor amperage, both blast furnaces casting (total): 245 amps

B. Motor amperage, one blast furnace casting: 131 amps

C. Blast Furnace A iron spout damper positions (3): 2 or less open all of the time; 3 open less than 5 minutes

D. Blast Furnace B tilting runner damper position: open

i. Pursuant to 40 CFR 63.7824(c), the Permittee may change the operating limits for the capture system if the Permittee meets the following requirements:

i. Submits a written notification to the Illinois EPA of the Permittee's request to conduct a new performance test to revise the operating limit.

ii. Conducts a performance test to demonstrate compliance with the applicable emission in Table 1 to 40 CFR 63 Subpart FFFFF.

iii. Establishes revised operating limits according to the applicable procedures in 40 CFR 63.7824(a).

j. Monitoring and Collecting Data pursuant to 40 CFR 63.7832:

i. Except for monitoring malfunctions, out-of-control periods as specified in 40 CFR 63.8(c)(7), associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the Permittee shall monitor continuously (or collect data at all required intervals) at all times an affected source is operating.

ii. The Permittee may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels or to fulfill a minimum data availability requirement, if applicable. The Permittee shall use all the data collected during all other periods in assessing compliance.

iii. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

k. Pursuant to the operation and maintenance requirements of the O/M plan required by 40 CFR 63.7800(b), the Permittee shall comply with following inspection procedures for the capture systems:

Monthly inspections of the equipment that is important to the performance of the total capture system. This inspection must include observations of the physical appearance of the equipment (e.g., presence of holes in ductwork or hoods, flow constrictions caused by dents or accumulated dust in the ductwork, and fan erosion). Repair of any defect or deficiency in the capture system shall be done before the next scheduled inspection.

l. Inspection and Monitoring for BFG Flares [Section 39.5(7)(d) of the Act]

i. For BFG flare #1, the Permittee shall either:

A. Install, operate and maintain instrumentation, with alarm, to confirm the presence of a flame at the flare tip; or

B. Monitor the presence of a pilot flame in accordance with Condition 7.4.8(l)(ii); or

C. Verify daily, the following to ensure BFG flare #1 is operating: The presence of a flame or thermal plume at the tip of the flare and that the flare gas header has a positive pressure.

ii. For BFG flare #2, the Permittee shall monitor the presence of a flare pilot flame using a thermocouple or other equivalent device to detect the presence of a flame.

iii. The Permittee shall perform detailed inspections of each BFG flare every 18 months. These inspections shall include all maintenance and repair activities performed based on the inspection results. If the flare cannot be inspected within 18 months, as required, the Permittee may request in writing from IEPA's Permit Section an extension of time to complete this inspection. The request for an extension must be supported with adequate justification for the extension and an assurance that the flare is continuing to operate without any problems. Under no circumstances shall the extension go beyond an additional 6 months.

m. Pursuant to Permits 72080034 and 72080036 [T1]:

i. The Permittee shall maintain and operate a pressure drop continuous recording system on the casthouse baghouse. The recorded data shall be retained for a period of six months shall be made available to the Illinois EPA personnel upon request.

ii. The Permittee shall maintain and operate a continuous pressure drop recording system on the iron spout baghouse.

n. The Permittee shall conduct observations for opacity for operations associated with the blast furnace in accordance with USEPA Method 9 for a minimum of 30 minutes for each operation unless no visible emissions are observed during the first 12 minutes of observations:

i. Blast furnace charging: Annually

ii. Blast furnace stoves stacks: Semiannually

iii. Slag pits: Quarterly

7.4.9 Recordkeeping Requirements

The Permittee shall maintain records of the following items for the affected Blast Furnaces Processes, pursuant to Sections 39.5(7)(a), (e) and (p) of the Act:

a. 40 CFR Part 63 Subpart FFFFF (40 CFR 63.7842 and 63.7843):

i. The Permittee shall keep the following records, as specified in 40 CFR 63.7842 (a)(1) through (a)(3):

A. A copy of each notification and report that the Permittee submitted to comply with 40 CFR 63 Subpart FFFFF, including all documentation supporting any initial notification or notification of compliance status that the Permittee submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv).

B. The records in 40 CFR 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

C. Records of performance tests, performance evaluations, and opacity observations as required in 40 CFR 63.10(b)(2)(viii).

ii. The Permittee shall keep the records in 40 CFR 63.6(h)(6) for visual observations.

iii. The Permittee shall keep the records required in 40 CFR 63.7833 and 63.7834 (including a current copy of the operation and maintenance plan) to show continuous compliance with each emission limitation and operation and maintenance requirement that applies to the Permittee.

iv. The Permittee shall keep its records in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1).

v. As specified in 40 CFR 63.10(b)(1), the Permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

vi. The Permittee shall keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report,

or record, according to 40 CFR 63.10(b)(1). The Permittee may keep the records offsite for the remaining 3 years.

b. 40 CFR Part 63 Subpart FFFFF [40 CFR 63.7834(b)]:

The Permittee shall maintain a current copy of the operation and maintenance plan required in 40 CFR 63.7800(b) onsite and available for inspection upon request.

c. The following records of Permits #72080034, #72080036 and #95010001:

i. The Permittee shall maintain records for each beaching event in which iron is beached that, as a minimum, shall include:

A. An explanation why beaching occurred.

B. The date, time and duration of beaching.

C. The measures used to reduce the amount of beaching.

D. The maximum rate of beaching, tons/minute, (or information showing that the beaching rate did not exceed 20 tons/minute).

d. Records for Startups of Affected Blast Furnace Processes, pursuant to Section 39.5(7)(b) of the Act

i. The Permittee shall maintain startup procedures for each affected blast furnace process, as required by Condition 7.4.5-2(b)(ii)(C).

ii. The Permittee shall maintain the following records for each startup of an affected blast furnace process:

A. Date, time and duration of the startup.

B. A description of the startup and reason(s) for the startup.

C. Whether a violation of an applicable standard may have occurred during startup accompanied by the information in Condition 7.4.9(d)(iv) if a violation may have or did occur.

D. Whether the established startup procedures, maintained above, were followed accompanied by the information in Condition 7.4.9(d)(iii) if there were departure(s) from those procedures.

iii. If the established startup procedures were not followed during a startup, the Permittee shall maintain the following records:

A. A description of the departure(s) from the established procedures.

B. The reason(s) for the departure(s) from the established procedures.

C. An explanation of the consequences of the departure(s) for emissions, such as whether the departure(s) prolonged the startup or resulted in additional emissions, and if so,

1. The actions taken to minimize emissions and the duration of the startup; and

2. An explanation whether similar incidents might be prevented in the future and if so, the corrective actions taken or to be taken to prevent similar incidents.

iv. If a violation did or may have occurred during a startup, the Permittee shall maintain the following records:

A. Identification of the applicable standard(s) that were or may have been violated.

B. An explanation of the nature of such violation(s), including the magnitude of such excess emissions.

C. A description of the actions taken to minimize the magnitude of emissions and duration of the startup.

D. An explanation whether similar incidents could be prevented or ameliorated in the future and if so, a description of the actions taken or to be taken to prevent similar incidents in the future.

e. Records for Malfunctions or Breakdowns

Pursuant to 35 IAC 201.263, the Permittee shall maintain records of continued operation of the affected Blast Furnace Processes as addressed by Condition 7.4.5-2(b)(i), during malfunctions or breakdowns, which at a minimum, shall include the following records. The preparation of these records shall be completed within 45 days of an incident, unless the Permittee conducts a root cause analysis for the incident, in which case the preparation of

these records, other than the root cause analysis, shall be completed within 120 days of the incident.

i. Date, time and duration of the incident.

ii. A detailed description of the incident, including:

A. A chronology of significant events during and leading up to the incident.

B. Relevant operating data for the unit, including information such as operator log entries and directives provided by management during the incident.

C. The measures taken to reduce the quantity of emissions and the duration of the incident including the resources utilized to address the incident.

D. The magnitude of emissions during the incident.

iii. An explanation why continued operation of an affected blast furnace was necessary to prevent personnel injury or prevent equipment damage.

iv. A discussion of the cause(s) or probable cause(s) of the incident including the following:

A. Whether the incident was sudden, unavoidable, or preventable, including:

1. Why the equipment design did not prevent the incident;

2. Why better maintenance could not have avoided the incident;

3. Why better operating practices could not have avoided the incident; and

4. Why there was no advance indication for the incident.

B. Whether the incident stemmed from any activity or event that could have been foreseen, avoided or planned for.

C. Whether the incident was or is part of a recurring pattern indicative of inadequate design, operation or maintenance.

v. A description of any steps taken to prevent similar future incidents or reduce their frequency and severity.

vi. As an alternative to keeping the records required by Condition 7.4.9(e)(iv), the Permittee may perform a root cause analysis. For this purpose, a root cause analysis is an analysis whose purpose is to determine, correct and eliminate the primary causes of the incident and the excess emissions resulting there from. If the Permittee performs a root cause analysis method that would define the problem, define all causal relationships, provide a causal path to the root cause, delineate the evidence, and provide solutions to prevent a recurrence. Such an analysis shall be completed within one year of the incident.

f. Recordkeeping for Backdrafting.

The Permittee shall maintain records for each period when an affected blast furnace is backdrafted. These records shall include, at a minimum for each occurrence, the blast furnace identification, date and timeframe of backdraft, reason for backdrafting (e.g., planned shutdowns and/or routine maintenance), and steps taken to minimize emissions during the backdraft period.

g. Records for BFG Flares

The Permittee shall maintain the following records for BFG flares:

i. Records of opacity observations performed as required by Condition 7.4.7(d).

ii. Records of inspections and maintenance activities conducted pursuant to Condition 7.4.8(l).

iii. For BFG flare #2, date and duration of any time when the pilot flame monitoring equipment of the affected unit was not in operation, with explanation.

iv. Date and duration of any time when there was no pilot flame present at the flare, with explanation.

v. Date, duration and description of any other deviations.

h. The Permittee shall maintain the following operating records for the affected blast furnaces:

i. Monthly and annual usage of natural gas, blast furnace gas and coke oven gas (million ft^3) used by the affected blast furnace stoves.

ii. Blast Furnace hot metal production (total combined daily, monthly and annual in tons), including documentation on iron and slag losses.

iii. Records of iron pellets charged (tons/month and tons/year).

iv. Records of slag processed (tons/month and tons/year).

v. For overlapping tapping of both furnaces, records to demonstrate that the tapping rate of each furnace does not exceed 6 tons per minute.

vi. If the Permittee operates under manufacturer's specifications or manufacturer's instructions, the Permittee shall maintain such manufacturer's documentation, which shall be kept at the facility as part of the required records.

vii. Records identifying process upsets in the operations at the casthouse that result in the generation of additional opacity or PM emissions, such as refractory clay falling into the trough during a missed stop. For these upsets, these records shall include the time of the upset, a description of the upset and a discussion of the consequences for opacity and PM emissions from the casthouse.

i. The Permittee shall keep the following records related to the emissions of the affected blast furnace processes to verify compliance with the applicable limits in Condition 7.4.6(b) through (g):

i. A file containing the emission factors used by the Permittee to determine emissions of different pollutants from the various processes, with supporting documentation. These records shall be reviewed and updated by the Permittee as necessary to assure that the emission factors that it uses to determine emissions of the processes do not understate actual emissions, including review when emission testing is conducted for such processes. These records shall be prepared and copies sent to the Illinois EPA in accordance with Condition 5.9.6(c).

ii. Records for any periods of operation of such processes that are not otherwise addressed in the required records during which the established emission factor in Condition 7.4.9(i)(i) would understate actual emissions of the process, with description of the period of operation and an estimate of the additional emissions during such period that would not be accounted for by the established factor, with supporting explanation and calculations.

iii. Records for the annual emissions of such processes for comparison to the limits in Conditions 7.4.6(b) through (f), with supporting calculations.

iv. Records for combined annual emissions of the affected processes, based on the summation of the above data, for comparison to the limits in Condition 7.4.6(g).

7.4.10 Reporting Requirements

a. 40 CFR 63 Subpart FFFFF (40 CFR 63.7841):

i. Compliance report due dates. The Permittee shall submit the semiannual compliance reports to the Illinois EPA according to the following requirements:

A. Semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

B. Each compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date comes first after the end of the semiannual reporting period.

ii. Compliance report contents. Each compliance report must include the following information:

A. Company name and address.

B. Statement by a responsible official, with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

C. Date of report and beginning and ending dates of the reporting period.

D. If the Permittee had a startup, shutdown, or malfunction during the reporting period and the Permittee took actions consistent with the source's startup, shutdown, and malfunction plan, the compliance report must include the information in 40 CFR 63.10(d)(5)(i).

E. If there were no deviations from the continuous compliance requirements in 40 CFR 63.7833 and 63.7834 that apply to the Permittee, a statement that there were no deviations from the emission limitations or operation and

maintenance requirements during the reporting period.

F. If there were no periods during which a continuous monitoring system (including a CPMS, COMS, or continuous emission monitoring system (CEMS)) was out-of-control as specified in 40 CFR 63.8(c)(7), a statement that there were no periods during which the CPMS was out-of-control during the reporting period.

G. For each deviation from an emission limitation in 40 CFR 63.7790 that occurs at an affected source where the Permittee is not using a continuous monitoring system (including a CPMS, COMS, or CEMS) to comply with an emission limitation in Subpart FFFFF, the compliance report must contain the information described in Condition 7.4.10(a)(ii) and the following information (this includes periods of startup, shutdown, and malfunction):

1. The total operating time of each affected source during the reporting period.

2. Information on the number, duration, and cause of deviations (including unknown cause, if applicable) as applicable and the corrective action taken.

H. For each deviation from an emission limitation occurring at an affected source where the Permittee is using a continuous monitoring system (including a CPMS or COMS) to comply with the emission limitation in Subpart FFFFF, the Permittee must include the information described in Condition 7.4.10(a)(ii) and the following information (this includes periods of startup, shutdown, and malfunction):

1. The date and time that each malfunction started and stopped.

2. The date and time that each continuous monitoring was inoperative, except for zero (low-level) and high-level checks.

3. The date, time, and duration that each continuous monitoring system was out-of-control as specified in 40 CFR 63.8(c)(7), including the information in 40 CFR 63.8(c)(8).

4. The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

5. A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

6. A breakdown of the total duration of the deviations during the reporting period including those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

7. A summary of the total duration of continuous monitoring system downtime during the reporting period and the total duration of continuous monitoring system downtime as a percent of the total source operating time during the reporting period.

8. A brief description of the Blast Furnace processes.

9. A brief description of the continuous monitoring system.

10. The date of the latest continuous monitoring system certification or audit.

11. A description of any changes in continuous monitoring systems, processes, or controls since the last reporting period.

iii. Immediate startup, shutdown, and malfunction report. If the Permittee had a startup, shutdown, or malfunction during the semiannual reporting period that was not consistent with the source's startup, shutdown, and malfunction plan, the Permittee shall submit an immediate startup, shutdown, and malfunction report according to the requirements in 40 CFR 63.10(d)(5)(ii).

b. Reporting requirements for malfunctions and breakdowns (Permits #72080034, #72080036 and #95010001):

The Permittee shall notify the Illinois EPA's regional office by telephone as soon as possible during normal working hours, but no later than the next Agency business day, upon the occurrence of excess emissions due to malfunctions or breakdowns. The Permittee shall submit a quarterly report to the Illinois EPA's regional office in Collinsville providing an explanation of the occurrence of such events.

c. i. Pursuant to Section 39.5(7)(f)(ii) of the Act, the Permittee shall promptly notify the Illinois EPA, Air Compliance Section, within 30 days of deviations by the affected blast furnace processes from applicable requirements unless a NESHAP standard specifies a different timeframe, as follows:

A. Requirements in Condition 7.4.3(b) through (f).

B. Requirements in Condition 7.4.5-1.

C. Requirements in Condition 7.4.5-3.

D. Requirements in Condition 7.4.5-4.

E. Requirements in Condition 7.4.6(a) through (j).

ii. All such deviations shall be summarized and reported as part of the semiannual monitoring report required by Condition 8.6.1.

iii. The Permittee shall notify the Illinois EPA, Air Compliance Section, of all other deviations as part of the semiannual monitoring reports required by Condition 8.6.1.

iv. All required deviation reports described in Condition 7.4.10(c) above shall contain the following information:

A. Date, time and duration of the deviation;

B. Description of deviation;

C. Probable cause of the deviation;

D. Any corrective action or preventative measures taken;

d. Reporting on the State startup authorization shall be performed in accordance with Condition 5.10.5-1.

e. Reporting on the Federal SSM authorization shall be performed in accordance with Condition 5.10.5-3.

7.4.11 Operational Flexibility

Backdrafting the blast furnaces in order to conduct planned/routine maintenance (not associated with malfunction and breakdowns) shall follow procedures designed to minimize the release of emissions during such activities.

7.4.12 Compliance Procedures

a. For affected blast furnace processes, compliance with the applicable standards of Condition 7.4.3 is addressed by the work practices, testing, monitoring, recordkeeping and reporting requirements in Section 7.4 of this permit.

b. Compliance with the production/emission limits of Conditions 7.4.6 and 5.6.2 is addressed by the work practices, testing, monitoring, recordkeeping, and reporting requirements in Sections 7.4 and 5 of this permit.

7.4.13 Compliance Schedule and Current Enforcement Status

a. The Permittee shall comply with the following schedule of compliance related to SO_2 emissions from combustion of Blast Furnace Gas in various emission units at the source, as established in accordance with Consent Order No. 05-CH-750 (December 18, 2007 as amended on December 23, 2009):

Commitment	Timing
Use the correct emission factor for the Blast Furnace Gas SO_2 emissions when calculating, recording and reporting SO_2 emissions and for any other purpose under the Act.	Immediately and at all times going forward.
Work with the Illinois EPA, including providing additional information to the Agency when requested.	Within 30 days of the request.
Obtain a revised PSD Construction Permit.	Subject to Agency final issuance.

b. Submittal of Progress Reports

Quarterly Progress Reports shall be submitted beginning with the fourth quarter of 2009 and ending upon the achievement of compliance. Each quarterly report shall be submitted no later than 30 days after the end of the

corresponding calendar quarter. The Progress Report shall contain at least the following:

i. The required date for achieving commitments, and actual dates when such commitments were achieved.

ii. Any commitments accepted by the Permittee or otherwise established for the affected BOF as part of the resolution of the above referenced Consent Order, with the associated timing for each commitment.

iii. A discussion of progress in complying with commitments that is subject to future deadlines.

iv. If any commitment was not met, an explanation of why the required timeframe or commitment was not met, and any preventive or corrective measures adopted to achieve required commitment.

c. After completion of all required commitments and certification of compliance, as identified in Condition 7.4.13(a) no further Quarterly Progress Reports are required to be submitted.

Note: US Steel informed the Illinois EPA during deliberations on Consent Order 05-CH-750 of possible violations involving SO2 emissions from use of Blast Furnace Gas. The violations involved exceedances of the SO2 limit in Construction Permit 95010001 issued on July 23, 1996. The violations were addressed, working with the Office of the Illinois Attorney General, in Consent Order 05-CH-750, which was entered on December 18, 2007 in the Circuit Court for the Third Judicial Circuit, Madison County, Illinois. This Consent Order required US Steel to submit a complete and accurate application including required SO2 modeling to modify Construction Permit 95010001 by January 31, 2008. That application has been submitted by US Steel.

7.4.14 State-Only Conditions

State-only conditions are not being established.

7.5 Basic Oxygen Processes

7.5.1 Description

Reladling and Desulfurization Stations:

Molten iron from the blast furnaces is transported to the BOF by torpedo cars. The iron is then transferred to the charging ladles at the reladling station. In the desulfurization stations a combination of lime and magnesium is injected into the molten iron to remove the sulfur. The sulfur reacts with the lime and magnesium and forms a layer of slag on the surface of the iron. A collection system with a positive pressure baghouse is used to control emissions of particulate matter from these stations.

Slag Skimming:

After the molten iron is desulfurized, the ladle it is moved to this station where a mechanical arm is used to scrape slag from the surface of the iron. This slag is scraped from the iron ladles and into slag pots. A collection system with a baghouse is used to control emissions from this process.

Basic Oxygen Furnaces (BOF):

A fresh BOF charge usually begins with scrap metal. The scrap is charged into the BOF vessel. Molten iron is then charged into the vessel. A secondary hood is utilized to capture emissions during the charge. During periods of reduced molten iron availability scrap may be preheated with a natural gas fired lance to increase the temperature and reduce the amount of molten iron needed for a heat of steel. The BOF is then closed off and an oxygen lance is inserted to begin the melting and refining process. The oxygen lance openings on each BOF is equipped with steam rings. The steam rings are control measures for emissions of particulate matter from the BOF during the "oxygen blow" or refining phase when oxygen is being fed into the furnaces. The steam rings would inject steam in the area between the oxygen lance and the "lance hole" in the lid of the furnaces, acting to suppress the emissions of particulate through this area during the refining phase. In the BOF, the injected oxygen reacts exothermically with the carbon in the iron generating heat which melts the scrap and reducing the amount of carbon in the bath thus converting the iron to steel. When the refining process is completed, the molten steel is poured into a steel transfer ladle. Materials such as aluminum, silica, and manganese are added, as required, depending upon the particular steel alloy being produced. After the molten steel is tapped, the remaining slag is then dumped into a slag ladle. Emissions from these operations are captured and controlled with an electrostatic precipitator (ESP).

Ladle Preheating and Drying:

In this unit, lances combust either natural gas or coke oven gas to produce the heat needed to dry and preheat iron and steel handling ladles. The refractory linings of freshly re-bricked or repaired ladles must be completely dried and preheated before use. The drying process is necessary because any moisture left in the refractory would immediately vaporize and expand when the ladles are filled with molten iron or steel. This sudden expansion could cause the refractory lining to split which would allow the molten iron and steel to come into contact with, and damage the shell of the ladle. Emissions from this unit consist of particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide and organic materials generated by fuel combustion.

Ladle Metallurgy Furnaces (LMF) and Argon Stirring Stations:

At the LMF station and the argon stirring stations, final adjustments are made to the composition of a ladle of steel and the steel is held pending casting. At the LMF station, electricity can also be used to heat a ladle of steel if it has cooled below the range at which steel can be cast.

If the steel does not need to be reheated and at most minor adjustments are needed to its composition, the ladle of steel goes to one of the two argon stirring stations. At these stations, stirring lances are inserted into the steel and argon is pumped into the steel to maintain uniform composition and temperature. A baghouse is also used to control emissions from the operations.

Note: This narrative description is for informational purposes only and is not enforceable.

7.5.2 List of Emission Units and Air Pollution Control Equipment

Location	Basic Oxygen Process Descriptions	Date Constructed	Emission Control Equipment
Basic Oxygen Process Furnace Shop (BOPF)	Hot Metal Transfer Station	Prior to 05/1983	Reladle/ Desulfurization Baghouse
	(2) Hot Metal Desulfurization Stations		
	Slag Skimming Station	1985	Skimmer Baghouse
	Basic Oxygen Furnaces (BOF) #1 and #2 with Steam Rings	Prior to 08/1972	Electrostatic Precipitator
	Ladle Drying/Preheating (coke oven gas and natural gas modes)	Prior to 08/1972	None

Location	Basic Oxygen Process Descriptions	Date Constructed	Emission Control Equipment
	Ladle Metallurgy Furnace (LMF) Station	Prior to 1986	Baghouse #2
	Argon Stirring Stations	Around 1988	

7.5.3 Applicable Provisions

a. Pursuant to 35 IAC 212.446, emissions of particulate matter from basic oxygen processes shall be controlled as follows:

i. Charging, Refining and Tapping (BOF Operations). Particulate matter emissions from all basic oxygen furnaces (BOF) shall be collected and ducted to pollution control equipment. Emissions from basic oxygen furnace operations during the entire cycle (operations from the beginning of the charging process through the end of the tapping process) shall not exceed the allowable emission rate specified by 35 IAC 212.322. For purposes of computing the process weight rate, nongaseous material charged to the furnace and process oxygen shall be included. No material shall be included more than once [35 IAC 212.446(a)].

ii. Hot Metal Transfer, Hot Metal Desulfurization and Ladle Lancing.

Particulate matter emissions from hot metal transfers to a mixer or ladle, hot metal desulfurization operations and ladle lancing shall be collected and ducted to pollution control equipment, and emissions from the pollution control equipment shall not exceed 69 mg/dscm (0.03 gr/dscf) [35 IAC 212.446(b)(1)].

iii. For openings in the building housing the BOF, no person shall cause or allow emissions to exceed an opacity of 20 percent, as determined by averaging any 12 consecutive observations taken at 15 second intervals [35 IAC 212.446(c)].

b. Pursuant to 35 IAC 212.458, no person shall cause or allow emissions of PM_{10}, other than that of fugitive particulate matter, into the atmosphere to exceed the following limits during any one hour period:

i. 32.25 ng/J (0.075 lbs/mmBtu) of heat input from the burning of coke oven gas (at ladle dryers/preheaters) [35 IAC 212.458(b)(9)].

ii. 27.24 kg/hr (60 lbs/hr) and 0.1125 kg/Mg (0.225 lbs/T) of total steel in process whichever limit is more stringent for the total of all basic oxygen furnace operations (charging, refining and tapping, as described in 35 IAC 212.446(a)) and measured at the BOF stack [35 IAC 212.458(b)(23)].

iii. 22.9 mg/scm (0.01 gr/scf) from any process emissions unit, except as otherwise provided in 35 IAC 212.458 or in 212.443 and 212.446 [35 IAC 212.458(b)(7)].

c. Pursuant to 35 IAC 212.123(a), no person shall cause or allow the emission of smoke or other particulate matter, with an opacity greater than 30 percent, into the atmosphere from any emission unit other than those emission units subject to the requirements of 35 IAC 212.122, except as allowed by 35 IAC 212.123(b) and 212.124.

d. The Basic Oxygen Processes are subject to 40 CFR Part 63, Subpart FFFFF, Integrated Iron and Steel Manufacturing Facilities. Applicable provisions of this NESHAP are addressed below and in other conditions of this section of the permit.

e. Pursuant to 40 CFR 63.7790(a) and Table 1 to 40 CFR Part 63 Subpart FFFFF, the emissions from the Basic Oxygen Processes shall not exceed the following limits applicable to operation at existing basic oxygen process furnace (BOPF) identified in paragraphs 9 through 12 of Table 1 to Subpart FFFFF:

i. The Permittee must not cause to be discharged to the atmosphere any gases that exit from a primary emission control system for a BOPF with an open hood system at an existing BOPF shop that contain, on a flow-weighted basis, particulate matter in excess of 0.02 gr/dscf during the steel production cycle.

ii. For each hot metal transfer, slag skimming, and hot metal desulfurization operation, the Permittee must not cause to be discharged to the atmosphere any gases that exit from a control device that contain particulate matter in excess of 0.01 gr/dscf.

iii. For each ladle metallurgy furnace operation, the Permittee must not cause to be discharged to the atmosphere any gases that exit from a control device that contain particulate matter in excess of 0.01 gr/dscf.

iv. For each roof monitor on the BOPF Shop, the Permittee must not cause to be discharged to the atmosphere any secondary emissions that exit any opening in the BOPF shop or any other building housing the BOF or basic

oxygen process that exhibit opacity greater than 20 percent (3-minute average).

f. Pursuant to 40 CFR 63.7790(b)(3), for the electrostatic precipitator applied to control emissions from a BOF, the Permittee must maintain the hourly average opacity of emissions exiting the control device at or below 10 percent.

g. The basic oxygen furnaces are subject to 35 IAC 214.301, which provides that no person shall cause or allow the emission of sulfur dioxide into the atmosphere from any process emission source to exceed 2000 ppm.

7.5.4 Non-Applicability of Regulations of Concern

a. Pursuant to 35 IAC 212.324(a)(3) and 212.316(f), the emission limitations of 35 IAC 212.324 and 212.316 are not applicable to the basic oxygen processes because these operations are subject to specific emission standards and limitations contained in 35 IAC Part 212 Subpart R, as addressed in Condition 7.5.3(a).

b. Except where noted, 35 IAC 212.321 and 35 IAC 212.322 shall not apply to the steel manufacturing processes subject to 35 IAC 212.442 through 35 IAC 212.452 [35 IAC 212.441].

c. This permit is issued based on the affected basic oxygen processes not being subject to the applicable requirements of 35 IAC 219.301 because these processes do not emit photochemically reactive organic material as defined in 35 IAC 211.4690.

d. The basic oxygen processes are not subject to 35 IAC 216.121 because they are not fuel combustion emission units as defined in 35 IAC 211.2470.

7.5.5-1 Work Practices Provisions for Operation and Maintenance Plan (40 CFR 63.7800)

a. Pursuant to 40 CFR 63.6(e)(1)(i), the Permittee must always operate and maintain the basic oxygen processes, including air pollution control and monitoring equipment, in a manner consistent with good air pollution control practices for minimizing emissions at least to the levels required by 40 CFR 63 Subpart FFFFF.

b. The Permittee shall prepare and operate at all times according to a written operation and maintenance plan for each capture system or control device subject to an operating limit in 40 CFR 63.7790(b). Each plan shall address the following elements:

i. Monthly inspections of the equipment that is important to the performance of the total capture system (*e.g.*, pressure sensors, dampers, and damper switches). This inspection shall include observations of the physical appearance of the equipment (*e.g.*, presence of holes in ductwork or hoods, flow constrictions caused by dents or accumulated dust in the ductwork, and fan erosion). The operation and maintenance plan also must include requirements to repair any defect or deficiency in the capture system before the next scheduled inspection.

ii. Preventative maintenance for each control device, including a preventative maintenance schedule that is consistent with the manufacturer's instructions for routine and long-term maintenance.

iii. Corrective action procedures for baghouses equipped with bag leak detection systems. In the event a bag leak detection system alarm is triggered, the Permittee shall initiate corrective action to determine the cause of the alarm within 1 hour of the alarm, initiate corrective action to correct the cause of the problem within 24 hours of the alarm, and complete the corrective action as soon as practicable. Corrective actions may include, but are not limited to:

A. Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in emissions.

B. Sealing off defective bags or filter media.

C. Replacing defective bags or filter media or otherwise repairing the control device.

D. Sealing off a defective baghouse compartment.

E. Cleaning the bag leak detection system probe, or otherwise repair the bag leak detection system.

F. Shutting down the process producing the particulate emissions.

iv. Corrective action procedures for electrostatic precipitator (ESP) equipped with COMS. In the event an ESP exceeds the operating limit in 40 CFR 63.7790(b)(3), the Permittee shall take corrective

actions consistent with the site-specific monitoring plan in accordance with 40 CFR 63.7831(a).

7.5.5-2 Work Practices Provisions for Startup, Shutdown and Malfunction Plans and associated procedures

a. NESHAP Provisions

i. Pursuant to 40 CFR 63.7810, the Permittee must be in compliance with the emission limitations and operation and maintenance requirements in 40 CFR 63 Subpart FFFFF at all times, except during periods of startup, shutdown and malfunction as defined in 40 CFR 63.2

ii. Pursuant to 40 CFR 63.7810(c), the Permittee shall develop a written startup, shutdown, and malfunction plan for BOF according to the provisions of 40 CFR 63.6(e)(3).

iii. Pursuant to 40 CFR 63.7835:

A. Consistent with 40 CFR 63.6(e) and 63.7(e)(1), deviations from NESHAP requirements that occur during a period of startup, shutdown, or malfunction are not violations if the Permittee demonstrates to the Illinois EPA that the Permittee was operating in accordance with 40 CFR 63.6(e)(1).

B. The Illinois EPA will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in 40 CFR 63.6(e).

iv. The Permittee shall fulfill the applicable reporting requirements identified in Condition 5.10.5(b) and 40 CFR 63.7841(b)(4) and (c).

v. The Permittee shall keep records in accordance with 40 CFR 63.7842(a)(2) related to startup, shutdown and malfunction.

b. Provisions of State Emission Standards, pursuant to 35 IAC 201.149 and Part 201 Subpart I

i. Subject to the following terms and conditions, the Permittee is authorized to continue to operate in violation of the applicable standards as specified below in the event of a malfunction or breakdown.

A. For the basic oxygen furnace, the applicable state standards in Condition 7.5.3(a)(iii), (b)(ii) and (c)), and

B. For the LMF, the applicable state standards in Conditions 7.5.3(b)(iii) and (c).

Note: This authorization is provided because the Permittee applied for such authorization in its CAAPP application, generally explaining why such continued operation would be required to prevent injury to personnel or severe damage to equipment, and describing the measures that will be taken to minimize emissions from any malfunctions and breakdowns.

ii. This authorization only allows such continued operation as necessary to prevent injury to personnel or severe damage to equipment and does not extend to continued operation solely for the economic benefit of the Permittee.

iv. Upon occurrence of excess emissions due to malfunction or breakdown, the Permittee shall, as soon as practicable, repair the units and/or re-establish applicable control practices.

v. The Permittee shall fulfill the applicable recordkeeping requirements of Condition 7.5.9(g) and reporting requirements of Condition 5.10.5-2.

vi. Following notification to the Illinois EPA (see Condition 5.10.5-2(a)(i)) of a malfunction or breakdown with excess emissions, the Permittee shall comply with all reasonable directives of the Illinois EPA with respect to such incident.

vii. This authorization does not relieve the Permittee from the continuing obligation to minimize excess emissions during malfunction or breakdown. As provided by 35 IAC 201.265, an authorization in a permit for continued operation with excess emissions during malfunction and breakdown does not shield the Permittee from enforcement for any such violation and only constitutes a prima facie defense to such an enforcement action provided that the Permittee has fully complied with all terms and conditions connected with such authorization.

7.5.5-3 Work Practices from Permits 72080043, 95010001 and 10080021

a. Pursuant to Permit 72080043 [T1]:

i. Overlapping operations of the BOF vessels is allowed under the following conditions:

A. The hot metal charge of the second vessel shall be initiated and completed during the time between completion of the blow and start of tap on the first vessel while sufficient draft at the ESP capture system is established and maintained for both vessels.

B. The charge and/or blow on one vessel shall not begin until sufficient draft has been established at the associated ESP capture system (a.k.a., doghouse) and the alloy addition at the vessel tapping has been completed for at least 1 minute.

C. Sufficient draft at the ESP capture system of the vessel being tapped shall be maintained for at least 1 minute after alloy addition has been completed. After such period, the capture system draft may be transferred over to the other vessel in order to satisfy Condition (A) above.

D. Only overlapping of the hot metal charge of the second vessel after the end of blow and prior to onset of tap of the first vessel and overlapping of tapping of the first vessel, after alloy addition, and the hot metal charge and/or blow on the second vessel are allowed.

E. Condition (B) and (C) above shall be part of the Standard Operating Procedure (SOP) of the BOF vessels.

ii. Each BOF vessel shall be equipped with a Fume Suppression System which shall be in use at all times that tapping is occurring during overlapping operations.

b. Pursuant to Permit 95010001 [T1]:

i. The BOF capture system shall be operated at the above minimum set points (see Condition 7.5.6(h)) until and unless the Illinois EPA approves a lower minimum set point based on a demonstration that a better level of particulate matter control will occur, except for purposes of emissions testing as related to the set point [T1].

ii. The Permittee shall operate, maintain, and repair the BOF ESP in a manner that assures compliance with the conditions of Permit 95010001 [T1].

iii. The Permittee shall maintain an adequate inventory of spare parts for the BOF ESP at all times [T1].

c. Pursuant to Permit 10080021 [T1]:

i. Beginning October 31, 2012, during the refining phase of operation, the steam rings on the BOFs shall be operated in accordance with written procedures developed by the Permittee that set forth the timing and rate of steam injection as related to furnace operation and reflect good air pollution control practice to minimize emissions of particulate matter.

ii. Prior to October 31, 2012, during the refining phase of operation, the steam rings on the BOFs shall be operated in accordance with good air pollution control practice to minimize emissions of particulate matter.

7.5.6 Production and Emission Limitations from Permit 95010001

a. Total combined production of liquid steel from the affected BOFs shall not exceed 11,000 net tons per day, averaged over any calendar month [T1].

b. BOF Shop Emissions (tons/yr total) shall not exceed the following limits [T1]:

PM	PM_{10}	NO_x	VOM	CO	Lead
510	451	70	12	16,097	1.43

c. BOF ESP Stack (charge, refine, tap) emissions shall not exceed the following limits [T1]:

Pollutant	Emission Factor (Lbs/Ton)	Maximum Emissions (Tons/Yr)
PM	0.16	262.80
PM_{10}	0.16	262.80
NO_x	0.0389	69.63
VOM	0.0060	10.74
CO	8.993	16,097.47
Lead	0.1934 lbs/hr	1.26

d. BOF Roof Monitor emissions shall not exceed the following limits [T1]:

Pollutant	Emission Factor (Lbs/Ton)	Maximum Emissions (Tons/Yr)
PM	0.0987	176.71
PM_{10}	0.06614	118.40
Lead	0.0129 lbs/hr	0.08

e. Hot Metal Desulfurization and Hot Metal Transfer emissions shall not exceed the following limits [T1]:

Pollutant	Emission Factor (Lbs/Ton)	Maximum Emissions (Tons/Yr)
PM	0.03721	58.88
PM_{10}	0.03721	58.88
VOM	0.0010	1.58
Lead	0.0133 lbs/hr	0.09

f. Hot metal charging and ladle slag skimming emissions shall not exceed the following limits [T1]:

Pollutant	Emission Factor (Lbs/Ton)	Maximum Emissions (Tons/Yr)
PM	0.0050	7.94
PM_{10}	0.0050	7.94

g. Emissions from Argon Stirring Station and Material Handling Tripper (Ladle Metallurgy Baghouse #2) shall not exceed the following limits (see Section 7.1):

Pollutant	Emission Factor (Lbs/Ton)	Maximum Emissions (Tons/Yr)
PM	0.00715	12.80
PM_{10}	0.00715	12.80

h. The stack gas pulpit set point of the BOF ESP control system shall be set in accordance with the following, so as to establish sufficient particulate matter capture efficiency of the charging and primary hoods [T1]:

i. Set point requirements while only a single BOF vessel is in operation:

A. Minimum set point during charging operation: 550,000 cfm;

B. Minimum set point during refining operation: 650,000 cfm; and

C. Minimum set point during tapping operation: 200,000 cfm (until one minute after completing alloy addition).

ii. During dual operation of BOF vessels (a.k.a., overlapping BOF operation) the minimum set point shall be 700,000 cfm.

i. Compliance with the annual limits shall be determined on a calendar year basis [T1].

Note: These provisions (Conditions 7.5.6(a) through (i)) were originally established in Construction Permit 95010001.

j. Emissions of particulate matter from the Ladle metallurgy station and the existing argon stirring station shall not exceed 16.20 TPY [T1].

k. The maximum process weight for 1) argon stirring, 2) ladle reheat, 3) alloy addition, 4) ladle slag skimming, and 5) hot metal desulfurization shall not exceed 356.7 t/hr for 8,760 hours per year [T1].

Note: These provisions (Conditions 7.5.6(j) and (k)) were originally established in Permit 83050042.

7.5.7 Testing Requirements

a. Testing requirements in 40 CFR Part 63 Subpart FFFFF:

i. Pursuant to 40 CFR 63.7821(b), for the Basic Oxygen Furnaces (which are equipped with a control device other than a baghouse), the Permittee shall conduct subsequent performance tests no less frequently than twice (at mid-term and renewal) during each term of the title V operating permit (i.e., this CAAPP permit).

ii. Pursuant to 40 CFR 63.7821(c), for each Basic Oxygen Furnace Process equipped with a baghouse, the Permittee shall conduct subsequent performance tests no less frequently than once during each term of the Title V operating permit (every 60 months).

iii. The Permittee shall use the following test methods for compliance demonstration with the emission limits for particulate matter [40 CFR 63.7822(b)]:

A. The Permittee shall determine the concentration of particulate matter according to the following test methods in Appendix A to 40 CFR Part 60.

1. Method 1 to select sampling port locations and the number of traverse points. Sampling ports must be located at the outlet of the control device and prior to any releases to the atmosphere.

2. Method 2, 2F, or 2G to determine the volumetric flow rate of the stack gas.

3. Method 3, 3A, or 3B to determine the dry molecular weight of the stack gas.

4. Method 4 to determine the moisture content of the stack gas.

5. Method 5, 5D, or 17, as applicable, to determine the concentration of particulate matter (front half filterable catch only).

B. The Permittee shall collect a minimum sample volume of 60 dry standard cubic feet (dscf) of gas during each particulate matter test run. Three valid test runs are needed to comprise a performance test.

iv. Pursuant to 40 CFR 63.7822(g), for the BOF ESP (which is a primary emission control system applied to emissions from a BOF with an open hood system), the Permittee shall complete the following requirements:

A. Sample only during the steel production cycle. The Permittee shall conduct sampling under conditions that are representative of normal operation. The Permittee shall record the start and end time of each steel production cycle and each period of abnormal operation; and

B. Sample for an integral number of steel production cycles. The steel production cycle begins when the scrap is charged to the BOF and ends 3 minutes after the slag is emptied from the vessel into the slag pot.

v. Pursuant to 40 CFR 63.7822(h), for a control device applied to emissions from BOPF shop ancillary operations (hot metal transfer, slag skimming, hot metal desulfurization, or ladle metallurgy), the Permittee shall sample only when the operation(s) is being conducted.

vi. The Permittee shall conduct each visible emissions performance test such that the opacity observations overlap with the performance test for particulate matter [40 CFR 63.7823(b)].

vii. The following test methods shall be used for opacity observations pursuant to 40 CFR 63.7823(d):

Using a certified observer, the Permittee shall determine the opacity of emissions according to Method 9 in Appendix A to Part 60 as specified below:

A. Instead of procedures in section 2.4 of Method 9 in Appendix A to 40 CFR Part 60, the Permittee shall record observations to the nearest 5 percent at 15-second intervals for at least three steel production cycles.

B. Instead of procedures in section 2.5 of Method 9 in Appendix A to 40 CFR Part 60, the Permittee shall determine the 3-minute block average opacity from the average of 12 consecutive observations recorded at 15-second intervals.

b. Pursuant to Sections 39.5(7)(d) and (p) of the Act, in conjunction with the testing of emissions required for an emission unit in the BOF shop by the NESHAP (Condition 7.5.7(a) which requires testing at the midterm and renewal of this CAAPP permit), the Permittee shall also have testing conducted to measure emissions of other pollutants as follows.

i. Testing shall be conducted for PM/PM_{10}*, lead and other pollutants as follow: BOF Furnaces (ESP) - NO_x, VOM and CO; and Hot Metal Desulfurization and Slag Skimming (Baghouses) - VOM.

* As an alternative to measurements for PM_{10} emissions, the measured results for PM, as determined in accordance with the NESHAP, shall be considered PM10, as provided for by 35 IAC 212.108.

ii. The relevant test method specified by the NESHAP or the following USEPA test methods shall be used for this testing, unless another USEPA test method is approved by the Illinois EPA during the review of a Test Plan submitted by the Permittee prior to testing.

Location of Sample Points	Method 1
Gas Flow and Velocity	Method 2
Flue Gas Weight	Method 3
Moisture	Method 4
VOM	Method 18 or 25A
NO_x	Method 7E or 19
CO	Method 10 or 10B
Lead	Method 29

iii. For this emission testing, test notifications and reporting shall be done by the Permittee in accordance with Condition 8.6.2 and 8.6.3 of this permit.

c. As provided by 35 IAC 212.446(c), observations to determine compliance with the opacity standard in 35 IAC 212.446(c) (see Condition 7.5.3(a)(iii)) shall be performed in accordance with 40 CFR Part 60, Appendix A, Method 9, incorporated by reference in 35 IAC 212.113, except that compliance shall be determined by averaging any 12 consecutive observations taken at 15 second intervals.

7.5.8 Monitoring and Inspection Requirements

a. Monitoring (40 CFR 63.7830)

i. For the capture system for secondary emissions from the Basic Oxygen Furnaces (which are subject to an operating limit in 40 CFR 63.7790(b)(1) established in Permittee's capture system operation and maintenance plan), the Permittee shall install, operate, and maintain a continuous parameter monitoring system (CPMS) according to the requirements in 40 CFR 63.7831(e) and the requirements in 40 CFR 63.7830(a)(1) through (3).

ii. The Permittee shall operate and maintain a bag leak detection system on Baghouse #2 and the slag skimmer baghouse according to 40 CFR 63.7831(f) and monitor the relative change in particulate matter loadings according to the requirements in 40 CFR 63.7832.

iii. The Permittee shall conduct inspections of each baghouse at the specified frequencies according to the following requirements [40 CFR 63.7830(b)(4)]:

A. Monitor the pressure drop across each baghouse cell each day to ensure pressure drop is within the normal operating range identified in the operation and maintenance manual.

B. Confirm that dust is being removed from hoppers through weekly visual inspections or other means of ensuring the proper functioning of removal mechanisms.

C. Check the compressed air supply for pulse-jet baghouses each day.

D. Monitor cleaning cycles to ensure proper operation using an appropriate methodology.

E. Check bag cleaning mechanisms for proper functioning through monthly visual inspections or equivalent means.

F. Make monthly visual checks of bag tension on reverse air and shaker-type baghouses to ensure that bags are not kinked (kneed or bent) or laying on their sides. The Permittee does not have to make this check for shaker-type baghouses using self-tensioning (spring-loaded) devices.

G. Confirm the physical integrity of the baghouse through quarterly visual inspections of the baghouse interior for air leaks.

H. Inspect fans for wear, material buildup, and corrosion through quarterly visual inspections, vibration detectors, or equivalent means.

iv. For the ESP controlling the BOF furnaces (which are subject to an opacity limit of 10 percent, hourly average, pursuant to 40 CFR 63.7790(b)(3)), the Permittee shall operate and maintain a continuous opacity monitoring system (COMS) according to the requirements in 40 CFR 63.7831(h) and monitor the hourly average opacity of emissions exiting the stack according to the requirements in 40 CFR 63.7832 [40 CFR 63.7830(d)].

If the hourly average opacity for the ESP exceeds the operating limit, the Permittee shall follow the following procedures [40 CFR 63.7833(g)]:

A. The Permittee shall initiate corrective action to determine the cause of the exceedance within 1 hour. During any period of corrective action, the Permittee must continue to monitor and record all required operating parameters for equipment that remains in operation. Within 24 hours of the exceedance, the Permittee shall measure and record the hourly average operating parameter value for the emission unit on which corrective action was taken. If the hourly average parameter value meets the applicable operating limit, then the corrective action was successful and the emission unit is in compliance with the applicable operating limit.

B. If the required initial corrective action was not successful, the Permittee shall complete additional corrective action within the next 24 hours (48 hours from the time of the exceedance). During any period of corrective action, the Permittee shall continue to monitor

and record all required operating parameters for equipment that remains in operation. After this second 24-hour period, the Permittee shall again measure and record the hourly average operating parameter value for the emission unit on which corrective action was taken. If the hourly average parameter value meets the applicable operating limit, then the corrective action was successful and the emission unit is in compliance with the applicable operating limit.

C. For purposes of 40 CFR 63.7833(g)(1) and (2), in the case of an exceedance of the hourly average opacity operating limit for an ESP, measurements of the hourly average opacity based on visible emission observations in accordance with Method 9 may be taken to evaluate the effectiveness of corrective action.

D. If the second attempt at corrective action required in paragraph 40 CFR 63.7833 (g)(2) was not successful, the Permittee shall report the exceedance as a deviation in the next semiannual compliance report according to 40 CFR 63.7841(b).

b. Installation, operation, and maintenance requirements for monitors [40 CFR 63.7831]

i. For the slag skimmer baghouse and Baghouse #2 (which are subject to 40 CFR 63.7830(b)(1)), the Permittee shall operate and maintain the bag leak detection system according to the following requirements [40 CFR 63.7831(f)]:

A. The system must be certified by the manufacturer to be capable of detecting emissions of particulate matter at concentrations of 10 milligrams per actual cubic meter (0.0044 grains per actual cubic foot) or less.

B. The system must provide output of relative changes in particulate matter loadings.

C. The system must be equipped with an alarm that will sound when an increase in relative particulate loadings is detected over a preset level. The alarm must be located such that it

can be heard by the appropriate plant personnel.

D. Each system that works based on the triboelectric effect must be installed, operated, and maintained in a manner consistent with the guidance document, "Fabric Filter Bag Leak Detection Guidance," EPA-454/R-98-015, September 1997. The Permittee may install, operate, and maintain other types of bag leak detection systems in a manner consistent with the manufacturer's written specifications and recommendations.

E. To make the initial adjustment of the system, the Permittee shall establish the baseline output by adjusting the sensitivity (range) and the averaging period of the device. Then, the Permittee shall establish the alarm set points and the alarm delay time.

F. Following the initial adjustment, the Permittee may not adjust the sensitivity or range, averaging period, alarm set points, or alarm delay time, except as detailed in the Permittee's operation and maintenance plan. The Permittee may not increase the sensitivity by more than 100 percent or decrease the sensitivity by more than 50 percent over a 365-day period unless a responsible official certifies, in writing, that the baghouse has been inspected and found to be in good operating condition.

G. Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

ii. For the ESP (which is subject to the opacity limit in 40 CFR 63.7790(b)(3)), the Permittee shall install, operate, and maintain a COMS according to the following requirements in 40 CFR 63.7831 (h)(1) through (4):

A. The Permittee shall install, operate, and maintain each COMS according to Performance Specification 1 in 40 CFR Part 60, Appendix B.

B. The Permittee shall conduct a performance evaluation of each COMS according to 40 CFR 63.8 and Performance Specification 1 in Appendix B to 40 CFR Part 60.

C. Each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

D. COMS data must be reduced to 6-minute averages as specified in 40 CFR 63.8(g)(2) and to hourly averages where required by 40 CFR 63 Subpart FFFFF.

c. Pursuant to the operation and maintenance requirements of the O/M plan required by 40 CFR 63.7800(b), the Permittee shall comply with following inspection procedures for the capture systems and controls:

Monthly inspections of the equipment that is important to the performance of the total capture system. This inspection must include observations of the physical appearance of the equipment (e.g., presence of holes in ductwork or hoods, flow constrictions caused by dents or accumulated dust in the ductwork, and fan erosion). Repair of any defect or deficiency in the capture system shall be done before the next scheduled inspection.

d. Monitoring of capture and control systems for Basic Oxygen Furnaces (from Permit 95010001):

i. The Permittee shall operate and maintain the waste gas suction monitor system for the capture system for the Basic Oxygen Furnace that continually measures and records each operation (i.e., for each charge, each refine, each tap) of each steel production cycle the static pressure in the main downcommer duct of the ESP emissions capture and transport system.

A. The Permittee shall use the waste gas suction monitoring system as a mechanism to ensure sufficient draft is maintained in the emissions capture hoods and transport ducts so as to maximize emissions capture and transport and minimize uncaptured emissions and emission leaks.

B. The Permittee shall operate and maintain the system to ensure that accurate and useful data is collected.

C. The Permittee shall continuously record the static pressure in the main down comer duct of the ESP emissions capture and transport system.

ii. The Permittee shall calibrate, operate, and maintain a continuous strip chart recorder or disk storage of the ESP stack gas flow rate as measured by the stack gas flow meter during ESP use.

iii. The stack gas flow meter shall be calibrated on at least a quarterly basis.

iv. A. The Permittee shall visually inspect at least monthly all visible BOF vessel enclosures, hooding and ducts used to capture and transport emissions for the BOF ESP control system.

B. A log shall be maintained of these inspections which includes observations of the physical appearance of the capture system and any noted deficiencies (e.g., the presence of any holes in ductwork or hoods, flow constrictions caused by dents or accumulated dust in ductwork, and fan erosion).

C. Any leaks or areas otherwise noted to be in need of repair, shall be repaired expeditiously.

e. Opacity observations for 35 IAC 212.446(c);

The following opacity observations shall be performed pursuant to Section 39.5(7)(a) and (p) of the Act:

i. The Permittee shall have the opacity of the exhaust of the building housing the BOF determined by a qualified observer in accordance with USEPA Method 9 while the affected BOF(s) is operating, as further specified below.

A. Observations of opacity shall be conducted on the following frequency unless absence of adequate daylight or weather conditions preclude scheduled observation, in which case, the next observations shall be conducted on the next operating day of the BOF during which observations of opacity can reasonably be conducted in accordance with USEPA Method 9, except that reading shall be taken as a 3-minute average (12 consecutive observations taken 15 seconds intervals).

B. If a baghouse is not installed for control of tapping emissions from the BOF, these readings shall be performed for at least five days out of every seven. A day is defined as any day when a BOF is in operation for a minimum of

four hours during conditions that are acceptable for Method 9 readings. A minimum of 60 consecutive minutes of opacity readings must be obtained and must encompass at least one steel production cycle. A production cycle is defined as the beginning of scrap charging to the completion of deslagging of the steelmaking vessel. Results of these readings shall be reduced to three minute rolling averages.

C. Beginning 30 days after initial startup of a baghouse for control of tapping emissions from the BOFs, the Permittee shall have the opacity of the exhaust of the building housing the BOF determined by a qualified observer in accordance with USEPA Method 9 while the affected BOF(s) are operating, as further specified below.

1. The duration of opacity observations for each test shall be one complete steel making cycle.

2. Observations of opacity shall be conducted on the following frequency unless absence of adequate daylight or weather conditions preclude scheduled observation, in which case, the next observations shall be conducted on the next operating day of the BOF during which observations of opacity can reasonably be conducted in accordance with USEPA Method 9.

3. On a weekly basis (at least once every seven operating days of BOF) except as provided below.

4. On a daily basis (at least 5 days out of seven operating days of BOF) if any of the five previous 3-minute average observations measured opacity of 18 percent or more, continuing on a daily basis until the maximum opacities measured in five consecutive daily observations are all less than 18 percent, at which time observations on a weekly basis shall resume.

ii. Upon written request by the Illinois EPA, additional opacity observations shall be conducted within 5 operating days for the BOF from the date of the request by the Illinois EPA or on the date agreed upon by the Illinois EPA, whichever is later. For

such observations conducted pursuant to a request from the Illinois EPA:

A. The Permittee shall notify the Illinois EPA at least 24 hours in advance of the date and time of these observations, in order to enable the Illinois EPA to witness the observations. This notification shall include the name and employer of the qualified observer(s).

B. The Permittee shall promptly notify the Illinois EPA of any changes in the time or date for observations.

C. The duration of these observations shall cover a complete heat or cycle of the affected BOF.

D. The Permittee shall provide a copy of the current certification for the opacity observer and observer's readings to the Illinois EPA at the time of the observations, if the Illinois EPA personnel are present.

E. The Permittee shall keep records for all opacity measurements for the BOF made in accordance with USEPA Method 9 for the affected operations that the Permittee conducts or that are conducted at its behest by individuals who are qualified to make such observations. For each occasion on which such measurements are made, these records shall include the formal report for the measurements, a description of the measurements that were made, the operating condition of the affected operations, the observed opacity, and copies of the raw data sheets for the measurements.

iii. A. The Permittee shall determine the opacity from the BOF ESP stack for at least one hour on any normal work day that the continuous opacity monitor on the BOF ESP stack has an outage that exceeds two consecutive hours and is still down. The readings shall commence as soon as possible after the opacity monitor has been down for two consecutive hours. If meteorological conditions or lack of visibility preclude these observations from being conducted, then this shall be noted in the log book.

B. The opacity shall be determined in accordance with the observation procedures set out in 40 CFR Part 60, Appendix A, Method 9.

f. Monitoring and Collecting Data [40 CFR 63.7832]:

i. For purposes of the NESHAP, 40 CFR 63 Subpart FFFFF, except for monitoring malfunctions, out-of-control periods as specified in 40 CFR 63.8(c)(7), associated repairs, and required quality assurance or control activities (including as applicable, calibration checks and required zero and span adjustments), the Permittee shall monitor continuously (or collect data at all required intervals) at all times a subject control/capture system is operating.

ii. The Permittee may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels or to fulfill a minimum data availability requirement, if applicable. The Permittee shall use all the data collected during all other periods in assessing compliance.

iii. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

g. Operational Monitoring for Steam Rings from Construction Permit 10080021:

The Permittee shall install, maintain and operate a continuous monitoring system on each steam ring for the steam valve position (open or closed) and the rate at which steam is being injected.

7.5.9 Recordkeeping Requirements

The Permittee shall maintain records of the following items pursuant to Sections 39.5(7)(a) and (e) of the Act:

a. 40 CFR 63 Subpart FFFFF (40 CFR 63.7842 and 63.7843)

i. The Permittee shall keep the following records specified in 40 CFR 63.7842 (a)(1) through (a)(3):

A. A copy of each notification and report that the Permittee submitted to comply with 40 CFR 63 Subpart FFFFF, including all documentation supporting any initial notification or notification of compliance status that the Permittee submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv).

B. The records in 40 CFR 63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

C. Records of performance tests, performance evaluations, and opacity observations as required in 40 CFR 63.10(b)(2)(viii).

ii. For each COMS, the Permittee shall keep the following records specified in 40 CFR 63.7842 (b)(1) through (4):

A. Records described in 40 CFR 63.10(b)(2)(vi) through (xi).

B. Monitoring data for a performance evaluation as required in 40 CFR 63.6(h)(7)(i) and (ii).

C. Previous (that is, superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3).

D. Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

iii. The Permittee shall keep the records specified in 40 CFR 63.6(h)(6) for visual observations.

iv. The Permittee shall keep the records required in 40 CFR 63.7833 and 63.7834 to show continuous compliance with each emission limitation and operation and maintenance requirement that applies to the Permittee.

v. The Permittee shall keep the records in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1).

vi. As specified in 40 CFR 63.10(b)(1), the Permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

vii. The Permittee shall keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). The

Permittee may keep the records offsite for the remaining 3 years.

viii. The Permittee shall maintain a current copy of the operation and maintenance plan required in 40 CFR 63.7800(b) onsite and available for inspection upon request.

ix. A. The Permittee shall maintain a copy of the site-specific monitoring plan for each CPMS required by 40 CFR 63.7830, pursuant to 40 CFR 63.7831(a).

B. If the Permittee operates under manufacturer's specifications or manufacturer's instructions, such manufacturer's documentation shall be kept at the source as part of the required records.

b. Recordkeeping from Permits 72080043 and 95010001:

i. Operating time of the BOFs;

ii. Operating time of the capture systems and performance parameters, including air flow and fan amperage through the fan motors, gas temperature at inlet to ESP, damper settings, and steam injection rate;

iii. Operating time of the ESP and performance parameters, including voltage and amperage of each transformer/rectifier set, number of sections in use;

iv. All routine and nonroutine maintenance performed, including dates and duration of outages, inspection schedule and findings, leaks detected, repair actions, and replacements;

v. Total production of molten steel at the BOFs (daily, monthly, and annual production in tons);

vi. The Permittee shall keep a continuous strip chart recorder or disk storage of the stack gas flow rate during ESP use.

vii. The Permittee shall records for each steel production cycle the various stack gas flow rates for each process (i.e., for each charge, each refine, each tap) of each steel production cycle. That is, the Permittee shall be able to distinguish the measured flow rate of stack gas during each production cycle.

ix. Records of all opacity observations.

c. Recordkeeping carried over from Permit 08110016:

The operating and maintenance records that the Permittee maintains for the ESP shall include the following information for the induced draft fans on the ESP, in addition to other required information:

i. The periods of time when the BOFs operated with less than three properly functioning fans, with description and explanation.

ii. The periods of time when the BOFs are operating and a spare fan is not available, with the identity of the fan(s) that were not available and explanation, e.g., spare fan not available due to regularly scheduled maintenance or spare fan not available due to unplanned breakdown of the main bearings.

d. Recordkeeping for the steam rings on the BOF furnaces from Construction Permit 10080021:

i. A. The Permittee shall maintain a record of the steam valve position (open or closed) and the rate at which steam is being injected, as determined by the continuous monitoring systems required by Condition 7.5.8(g).

B. In addition to keeping records of the data measured by these monitoring systems, the Permittee shall keep records of the operation, calibration and maintenance of these systems.

ii. The Permittee shall maintain an operating log or other records for the BOF and steam rings that contain information generally documenting the steam rings are being operated in accordance with Condition 7.5.5-3(c), including information for the timing of the refining phase of each heat of a BOF furnace.

iii. The Permittee shall maintain detailed records of the following information for each heat in a BOF furnace in which the steam ring was not operated during the refining phase:

A. Identification of the heat and the duration of the incident, i.e., start time and time normal operation was achieved or the refining phase was completed.

B. Description of the incident, impact on effectiveness of the steam ring, probable cause, and corrective actions.

C. Verification that the established procedures were followed or a description and explanation why procedures were not followed.

Note: These records may be kept with other logs or records that the Permittee keeps for the BOF furnaces and their instrumentation and need not be kept as a separate record.

e. The Permittee shall keep annual records (tons/year) of steel processed at the slag skimming station, the argon stirring station and ladle metallurgy furnace station.

f. Emission Records

The Permittee shall keep the following records related to the emissions of the affected basic oxygen processes to verify compliance with the applicable limits in Conditions 7.5.6(b) through (g):

i. A file containing the emission factors used by the Permittee to determine emissions of different pollutants from such processes, with supporting documentation. These records shall be reviewed and updated by the Permittee as necessary to assure that the emission factors that it uses to determine emissions of the affected processes do not understate actual emissions, including review when emission testing is conducted for an affected process. These records shall be prepared and copies sent to the Illinois EPA in accordance with Condition 5.9.6(c), except that copies of the initial records shall be submitted to the Illinois EPA no later than August 3, 2012.

ii. Records for any periods of operation of an affected process that are not otherwise addressed in the required records during which the established emission factor in Condition 7.5.9(f)(i) would understate actual emissions of the process, with description of the period of operation and an estimate of the additional emissions during such period that are not accounted for by the established factor, with supporting explanation and calculations.

iii. Records for the annual emissions of such processes for comparison to the limits in Conditions 7.5.6(c) through (g), with supporting calculations.

iv. Records for combined annual emissions of such affected processes, based on the summation of the above data, for comparison to the limits in Condition 7.5.6(b).

g. In the operational logs or other records for the operation of the affected basic oxygen processes, the Permittee shall keep records identifying process upsets that result in the generation of additional opacity or PM emissions, such as loss of the slag cover on the molten metal in a vessel or a spill of molten metal. For these upsets, these records shall include the time of the upset, a description of the upset, and a discussion of the consequences for PM emissions from the affected basic oxygen processes.

h. Records for Malfunctions or Breakdowns

Pursuant to 35 IAC 201.263, the Permittee shall maintain records of continued operation of the affected Basic Oxygen Furnace and Ladle Metallurgy Furnace as addressed by Condition 7.5.5-2(b), during malfunctions or breakdowns, which at a minimum, shall include the following records. The preparation of these records shall be completed within 45 days of an incident, unless the Permittee conducts a root cause analysis for the incident, in which case the preparation of these records, other than the root cause analysis, shall be completed within 120 days of the incident.

i. Date, time and duration of the incident.

ii. A detailed description of the incident, including:

A. A chronology of significant events during and leading up to the incident.

B. Relevant operating data for the unit, including information such as operator log entries and directives provided by management during the incident.

C. The measures taken to reduce the quantity of emissions and the duration of the incident including the resources utilized to address the incident.

D. The magnitude of emissions during the incident.

iii. An explanation why continued operation of an affected basic oxygen furnace was necessary to prevent personnel injury or prevent equipment damage.

iv. A discussion of the cause(s) or probable cause(s) of the incident including the following,

A. Whether the incident was sudden, unavoidable, or preventable, including:

1. Why the equipment design did not prevent the incident;

2. Why better maintenance could not have avoided the incident;

3. Why better operating practices could not have avoided the incident; and

4. Why there was no advance indication for the incident.

B. Whether the incident stemmed from any activity or event that could have been foreseen, avoided or planned for.

C. Whether the incident was or is part of a recurring pattern indicative of inadequate design, operation or maintenance.

v. A description of any steps taken or to be taken to prevent similar future incidents or reduce their frequency and severity.

vi. As an alternative to keeping the records required by Condition 7.5.9(g)(iv), the Permittee may perform a root cause analysis. For this purpose, a root cause analysis is an analysis whose purpose is to determine, correct and eliminate the primary causes of the incident and the excess emissions resulting there from. If the Permittee performs a root cause analysis method that would define the problem, define all causal relationships, provide a causal path to the root cause, delineate the evidence, and provide solutions to prevent a recurrence. Such an analysis shall be completed within one year of the incident.

7.5.10 Reporting Requirements

a. 40 CFR Part 63, Subpart FFFFF (40 CFR 63.7841)

i. Compliance report due dates. Unless the Administrator has approved a different schedule, the Permittee shall submit a semiannual compliance report to the permitting authority according to the following requirements:

A. Semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

B. Each compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date comes first after the end of the semiannual reporting period.

ii. Compliance report contents. Each compliance report shall include the following information:

A. Company name and address.

B. Statement by a responsible official, with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

C. Date of report and beginning and ending dates of the reporting period.

D. If the Permittee had a startup, shutdown, or malfunction during the reporting period and the Permittee took actions consistent with the source's startup, shutdown, and malfunction plan, the compliance report must include the information in 40 CFR 63.10(d)(5)(i).

E. If there were no deviations from the continuous compliance requirements in 40 CFR 63.7833 and 63.7834 that apply to the Permittee, a statement that there were no deviations from the emission limitations or operation and maintenance requirements during the reporting period.

F. If there were no periods during which a continuous monitoring system (including a CPMS, COMS, or continuous emission monitoring system (CEMS)) was out-of-control as specified in 40 CFR 63.8(c)(7), a statement that there were no periods during which the CPMS was out-of-control during the reporting period.

G. For each deviation from an emission limitation in 40 CFR 63.7790 that occurs at each Basic Oxygen Process where the Permittee is not using a continuous monitoring system (including a CPMS, COMS, or CEMS) to comply with an emission limitation in 40 CFR Subpart FFFFF, the compliance report must contain the information described in Condition 7.5.10(a)(ii)(A) through (F) and the following information (this includes periods of startup, shutdown, and malfunction):

1. The total operating time of each Basic Oxygen Process during the reporting period.

2. Information on the number, duration, and cause of deviations (including unknown cause, if applicable) as applicable and the corrective action taken.

H. For each deviation from an emission limitation occurring at each Basic Oxygen Furnace Process where the Permittee is using a continuous monitoring system (including a CPMS or COMS) to comply with the emission limitation in 40 CFR 63 Subpart FFFFF, the Permittee shall include the following information (this includes periods of startup, shutdown, and malfunction):

1. The date and time that each malfunction started and stopped.

2. The date and time that each continuous monitoring was inoperative, except for zero (low-level) and high-level checks.

3. The date, time, and duration that each continuous monitoring system was out-of-control as specified in 40 CFR 63.8(c)(7), including the information in 40 CFR 63.8(c)(8).

4. The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

5. A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

6. A breakdown of the total duration of the deviations during the reporting period including those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

7. A summary of the total duration of continuous monitoring system downtime during the reporting period and the total duration of continuous monitoring system downtime as a percent of the total source

operating time during the reporting period.

8. A brief description of the Basic Oxygen Processes.

9. A brief description of the continuous monitoring system.

10. The date of the latest continuous monitoring system certification or audit.

11. A description of any changes in continuous monitoring systems, processes, or controls since the last reporting period.

iii. Immediate startup, shutdown, and malfunction report. If the Permittee had a startup, shutdown, or malfunction during the semiannual reporting period that was not consistent with the source's startup, shutdown, and malfunction plan, the Permittee shall submit an immediate startup, shutdown, and malfunction report according to the requirements in 40 CFR 63.10(d)(5)(ii).

b. Monthly Opacity Exceedance Report.

Monthly opacity exceedance reports for the BOF ESP shall be sent to the Illinois EPA Regional Office. These reports shall contain all opacity measurements which exceed 30 percent, averaged over a six minute period. These "excess opacity" reports shall provide, for each such incident, the percent opacity measured as well as the date and span of such incident. These reports shall state the reasons for the excess opacity. The reports shall also specify the dates of those periods during which the continuous monitoring system was not in operation [Section 39.5(7)(f)(ii) of the Act].

c. Reporting Requirements from Permit 08110016:

After the initial year of operation (12 calendar months) of the BOF with an ESP with four fans, the Permittee shall submit a report to the Illinois EPA that evaluates the impacts of the addition of a fourth fan to the ESP on the particulate matter emissions of the BOF. This report shall, at a minimum, include the following information and address impacts on both stack emissions of particulate matter (i.e., emissions from the ESP stack) and uncaptured emissions of particulate matter (e.g., emissions from the roof monitor of the BOPF Shop). This report shall be

submitted by the end of the third month following the initial year of operation with an ESP with four fans.

i. A description of typical operating scenarios in which the availability of a spare fan resulted in a decrease in short-term emissions, with an assessment of the changes in the hourly emission rates, with supporting documentation and calculations.

ii. A description of typical operating scenarios, if any, in which the availability of a spare fan resulted in an increase in short-term emissions, with an assessment of the changes in the hourly emission rates, with supporting documentation and calculations.

iii. An assessment of the overall effect of the addition of a fourth fan on actual annual emissions of the BOF, with supporting operating data and calculations.

d. i. Pursuant to Section 39.5(7)(f)(ii) of the Act, the Permittee shall promptly notify the Illinois EPA, Air Compliance Section, within 30 days of deviations by the Basic Oxygen Furnace Processes from applicable requirements, unless a NESHAP standard specifies a different timeframe, as follows:

A. Requirements in Condition 7.5.3.

B. Requirements in Condition 7.5.5-1.

C. Requirements in Condition 7.5.5-3.

D. Requirements in Condition 7.5.6(a) through (k).

ii. All such deviations shall be summarized and reported as part of the semiannual monitoring report required by Condition 8.6.1.

iii. The Permittee shall notify the Illinois EPA, Air Compliance Section, of all other deviations as part of the semiannual monitoring reports required by Condition 8.6.1.

iv. All required deviation reports described in Condition 7.5.10(d) above shall contain the following information:

A. Date, time and duration of the deviation;

B. Description of the deviation;

C. Probable cause of the deviation; and

D. Any corrective action or preventative measures taken.

e. Reporting on malfunction and breakdown shall be performed in accordance with Condition 5.10.5-2

f. Reporting Requirements from Permit 10080021:

i. Within six months of initial startup of the steam rings on the affected BOFs, the Permittee shall submit to the Illinois EPA: 1) A Project Report; and 2) A draft of the Permittee's written operating procedures for the steam rings, as required by Condition 7.5.5-3(c), for review and comment by the Illinois EPA. This Project Report shall include the following:

A. An assessment, with supporting documentation, of the effect of the steam rings on the opacity and, as feasible, particulate loading of the exhaust from the roof monitor of the BOPF Shop during refining, correlated with the rate of steam injection and other operating parameters of the BOF's and their control system; and

B. An identification of circumstances, if any, in which the steam rings must be operated to maintain compliance with applicable emission standards.

ii. The Permittee shall submit reports to the Illinois EPA on a semi-annual basis that include the following information for the operation of the steam rings on the affected BOFs:

A. Total number of heats during the reporting period.

B. Number of heats during the reporting period without steam rings operating properly, by type of incident, e.g., breakdown of the steam ring interrupting operation, malfunction of the steam ring with insufficient steam flow, or breakdown of support system.

g. Reporting on the Federal SSM authorization shall be performed in accordance with Condition 5.10.5-3.

7.5.11 Operational Flexibility/Anticipated Operating Scenarios

The Basic Oxygen Furnaces shall only be operated as top oxygen injected vessels, except that, for purposes of checkout and emission testing only, the furnaces may be operated as peripheral and bottom oxygen injected furnaces for a maximum of

120 days. Any further operation of the furnaces as other than top oxygen injected vessels shall be pursuant to a permit granted for such additional operation [72080043].

7.5.12 Compliance Procedures

a. Compliance with the applicable standards of Condition 7.5.3 is addressed by the work practices, testing, monitoring, recordkeeping and reporting requirements in Section 7.5 of this permit.

b. Compliance with the production/emission limits of Conditions 7.5.6 and 5.6.2 is addressed by the work practices, testing monitoring, recordkeeping and reporting requirements in Sections 7.5 and 5 of this permit.

7.5.13 Compliance Schedule and Current Enforcement Status

a. The Permittee shall comply with the following schedule of compliance applicable to BOF shop emissions and established in accordance with modified Consent Order 05-CH-750 (December 23, 2009):

Commitment	Timing
Certify compliance	March 31, 2011

b. Submittal of Progress Reports

Quarterly Progress Reports shall be submitted beginning with September 2011 and ending upon the achievement of compliance. Each quarterly report shall be submitted no later than 5 days after the end of the corresponding calendar month. The Progress Report shall contain at least the following:

i. The required date for achieving commitments, and actual dates when such commitments were achieved.

ii. Any commitments accepted by the Permittee or otherwise established for the affected BOF as part of the resolution of the above referenced Consent Order, with the associated timing for each commitment.

iii. A discussion of progress in complying with commitments that are subject to future deadlines.

iv. If any commitment was not met, an explanation of why the required timeframe or commitment was not met, and any preventive or corrective measures adopted to achieve required commitment.

c. After completion of all required commitments and certification of compliance, as identified in Condition

7.5.13(a) no further Quarterly Progress Reports are required to be submitted.

7.5.14 State-Only Conditions

State-only conditions are not being established.

7.6 Continuous Casting

7.6.1 Description

There are two continuous casting lines in operation in the caster building. Ladles of molten steel are hoisted by crane and placed in revolving turrets located at the top of the casters. Each turret holds two ladles at a time. When one ladle of steel has been cast the turret is rotated and the second ladle is tapped. The empty ladle is then replaced with a full one. The tapping process involves opening the taphole located on the bottom of the ladle and allowing the molten steel to flow into an intermediate chamber called a "Tundish". The Tundish has a taphole in the bottom through which the molten steel flows directly into the casters. The Tundish maintains a steady stream of molten steel flowing into the caster while ladles are being changed.

The molten steel from the casters continuously passes through a system of rollers and straighteners. Water is sprayed onto the slab throughout this process to complete the solidification of the slab.

Note: This narrative description is for informational purposes only and is not enforceable.

7.6.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Date Constructed	Emission Control Equipment
Continuous Casting	Steel Deslagging Station	Pre-1986	None
	Caster Molds 1 and 2	Pre-1990	None
	Casters #1 and #2: Spray Chambers	Pre-1981 (#1) Around 1988 (#2)	None
	Slab Cut-off	N/A	None
	Slab Ripping	N/A	None

7.6.3 Applicable Provisions and Regulations

a. The "affected continuous casting operations" for the purpose of these unit-specific conditions are the operations and emission units described in Conditions 7.6.1 and 7.6.2.

b. Pursuant to 35 IAC 212.458(b) and (c), the affected continuous casting operations shall comply with the following:

No person shall cause or allow emissions of PM_{10}, other than that of fugitive particulate matter, into the atmosphere to exceed the following limits during any one hour period:

i. 22.9 mg/scm (0.01 gr/scf) from any process emissions unit provided however that this limit shall not apply if there are no visible emissions, except if a stack test is performed, the absence of visible emissions is not a defense to a finding of violation [35 IAC 212.458(b)(7) and (c)]; and

ii. 5 percent opacity for continuous caster spray chambers or continuous casting operations [35 IAC 212.458(b)(8)].

Note: These standards currently do not apply to slab cut-off and slab ripping processes which are not vented through stacks.

c. Pursuant to 35 IAC 212.316(f), the affected continuous casting operations shall comply with the following:

No person shall cause or allow fugitive particulate matter emissions from any emission unit to exceed an opacity of 20 percent.

7.6.4 Non-Applicability of Regulations of Concern

a. The emission limitations of 35 IAC 212.324 are not applicable to any emission unit subject to a specific emissions standard or limitation contained in 35 IAC Part 212 Subpart R, Primary and Fabricated Metal Products and Machinery Manufacture, pursuant to 35 IAC 212.324(a)(3).

b. The affected continuous casting operations are not subject to 40 CFR Part 63 Subpart FFFFF, Integrated Iron and Steel Manufacturing, because continuous casting is not defined as part of BOPF and shop ancillary operations in 40 CFR 63.7782(c).

c. The affected continuous casting operations are not subject to 35 IAC 212.309 and 212.310 because those operations are not identified in 35 IAC 212.304 through 212.308.

7.6.5 Control Requirements and Work Practices

Pursuant to 35 IAC 212.450, particulate matter emissions from liquid steel charging in continuous casting operations shall be controlled by chemical or mechanical shrouds.

7.6.6 Production and Emission Limits from Permit 95010001 [T1]:

a. Emissions from Deslagging Station and associated Material Handling System (see Section 7.1) shall not exceed the following limits:

Pollutant	Emission Factor (Lbs/Ton)	Maximum Emissions (Tons/Yr)
PM	0.00355	6.35
PM_{10}	0.00355	6.35

b. Emissions from Caster Molds - Casting shall not exceed the following limits:

Pollutant	Emission Factor (Lbs/Ton)	Maximum Emissions (Tons/Yr)
PM	0.006	10.74
PM_{10}	0.006	10.74
NO_x	0.050	89.50

c. Emissions from Casters Spray Chambers shall not exceed the following limits:

Pollutant	Emission Factor (Lbs/Ton)	Maximum Emissions (Tons/Yr)
PM	0.00852	15.25
PM_{10}	0.00852	15.25

d. Emissions from Slab Cut-off shall not exceed the following limits:

Pollutant	Emission Factor (Lbs/Ton)	Maximum Emissions (Tons/Yr)
PM	0.0071	12.71
PM_{10}	0.0071	12.71

e. Emissions from Slab Ripping shall not exceed the following limits:

Pollutant	Emission Factor (Lbs/Ton)	Maximum Emissions (Tons/Yr)
PM	0.00722	12.92
PM_{10}	0.00722	12.92

f. Total Emissions from Continuous Casting operations shall not exceed the following limits:

	PM (Tons/Yr)	PM_{10} (Tons/Yr)	NO_x (Tons/Yr)
Continuous Casting Operations	71	71	90.0

g. Compliance with annual limits shall be determined on a calendar year basis [T1].

7.6.7 Testing Requirements

a. The Permittee shall conduct opacity observations for the affected continuous casting operations as specified below [Sections 39.5(7)(d) and (p) of the Act]:

i. Semi-annual observations shall be performed by a qualified observer in accordance with USEPA Method 9 for each spray chamber stack and continuous caster building openings while the casters are operating. The duration of opacity observations for each stack and the building shall be at least 30 minutes unless no visible emissions are observed from a stack or the building during the first 12 minutes of observations.

ii. Upon written request by the Illinois EPA, additional opacity observations shall be conducted within 5 operating days from the date of the request or by the date agreed upon by the Illinois EPA, whichever is later. For these observations:

A. The Permittee shall notify the Illinois EPA at least 24 hours in advance of the date and time of these observations, in order to enable the Illinois EPA to witness the observations. This notification shall include the name and employer of the qualified observer(s).

B. The Permittee shall promptly notify the Illinois EPA of any changes in the time or date for observations.

C. The duration of these observations shall be three hours for each spray chamber stack.

D. The Permittee shall provide a copy of the current certification for the opacity observer and observer's readings to the Illinois EPA at the time of the observations, if the Illinois EPA personnel are present.

b. The Permittee shall have emission tests conducted for the PM/PM_{10} emissions of the spray chambers of the affected continuous casting operations as specified below to verify

compliance with emission limits in Condition 7.6.6(c) [Sections 39.5(7)(d) and (p) of the Act]:

i. A. Emission testing shall be conducted within 30 months of the effective date of this permit condition. This testing shall be conducted for one caster as selected by the Illinois EPA.

B. Upon written request from the Illinois EPA, additional emission testing shall be conducted within 90 operating days from the date of the request or by the date agreed upon by the Illinois EPA, whichever is later.

ii. The following USEPA test methods shall be used for this testing, unless another USEPA method is approved by the Illinois EPA:

A.	Location of Sample Points	Method 1
B.	Gas Flow and Velocity	Method 2
C.	Flue Gas Weight	Method 3
D.	Moisture	Method 4
E.	PM/PM_{10}	Methods 5, 201 or 201A

iii. Observations for visible emissions and opacity shall be conducted during all emission tests in accordance with USEPA Methods 22 and 9, respectively, and the results of these observations included in the reports for emission testing.

iv. For this emission testing, test notifications and reporting shall be done by the Permittee in accordance with Conditions 8.6.2 and 8.6.3 of this permit.

7.6.8 Monitoring Requirements

The Permittee shall perform monthly inspections of the continuous casting operations. These inspections shall include [Sections 39.5(7)(a) and (d) of the Act]:

a. Inspection of the mechanical shrouds on the continuous casting operations to ensure their physical presence and integrity.

b. Observations for visible emissions from stacks conducted in accordance with Method 22. If visible emissions are observed, opacity observations by Method 9 shall be conducted within one week.

7.6.9 Recordkeeping Requirements

The Permittee shall maintain records of the following items for the affected continuous casting operations, pursuant to Sections 39.5(7)(a) and (e) of the Act:

a. Amount of steel cast (ton/mo and ton/yr).

b. The Permittee shall maintain records of the inspections required by Condition 7.6.8.

c. The Permittee shall keep the following records related to the emissions of the affected continuous casting operations:

i. A file containing the emission factors used by the Permittee to determine emissions of different pollutants from the various affected operations, with supporting documentation. These records shall be reviewed and updated by the Permittee as necessary to assure that the emission factors that it uses to determine emissions of the affected operations do not understate actual emissions. These records shall be prepared and copies sent to the Illinois EPA in accordance with Condition 5.9.6(c).

ii. Records for any periods of operation of an affected operations that are not otherwise addressed in the required records during which the established emission factor in Condition 7.6.9(c)(i) would understate actual emissions, with description of the period of operation and an estimate of the additional emissions during such period that would not be accounted for by the established factor, with supporting explanation and calculations.

iii. Records for the annual emissions of the various affected operations for comparison to the limits in Conditions 7.6.6(a) through (e), with supporting calculations.

iv. Records for combined annual emissions of the affected continuous casting operations, based on the summation of the above data, for comparison to the limits in Condition 7.6.6(f).

d. The Permittee shall keep records for all opacity readings for the affected continuous casting operations conducted in accordance with Condition 7.6.7.

7.6.10 Reporting Requirements

a. i. Pursuant to Section 39.5(7)(f)(ii) of the Act, the Permittee shall promptly notify the Illinois EPA, Air Compliance Section, within 30 days of deviations by

the affected continuous casting operations from applicable requirements, as follows:

A. Requirements in Condition 7.6.3(b) and (c).

B. Requirements in Condition 7.6.6.

ii. All such deviations shall be summarized and reported as part of the semiannual monitoring report required by Condition 8.6.1.

b. The Permittee shall notify the Illinois EPA, Air Compliance Section, of all other deviations as part of the semiannual monitoring reports required by Condition 8.6.1.

c. All deviation reports described in Condition 7.6.10 above shall contain the following:

i. Date, time and duration of the deviation;

ii. Description of the deviation;

iii. Probable cause of the deviation; and

iv. Any corrective action or preventive measures taken.

7.6.11 Operational Flexibility/Anticipated Operating Scenarios

Operational flexibility is not set for the affected continuous casting operations.

7.6.12 Compliance Procedures

For affected continuous casting, compliance with the applicable standards of Conditions 7.6.3(b) and (c) and with the limitations of Condition 7.6.6 is addressed by the work practices, testing, monitoring, recordkeeping and reporting requirements in Section 7.6 of this permit.

7.6.13 State-Only Conditions

State-only conditions are not being established.

7.7 Hot Strip Mill Reheat Furnaces

7.7.1 Description

Steel slabs are heated in the slab reheat furnaces, so they can be formed further in the facility's hot strip mill. Some of the slabs are shipped to the facility from outside suppliers.

The following fuels or combination of these fuels are fired by all the four furnaces: natural gas and coke oven gas (COG). In the past, the reheat furnaces also fired oil, but they no longer have that capability.

Note: This narrative description is for informational purposes only and is not enforceable.

7.7.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Date Constructed	Emission Control Equipment
Reheat Furnaces	Slab Reheat Furnaces #1, #2 & #3 equipped with low-NO_x burners Nominal firing rate: 322 mmBtu/hr each	Pre-1972	None
	Slab Reheat Furnace #4 equipped with low-NO_x burners Nominal firing rate: 495 mmBtu/hr	Pre-1977	None

7.7.3 Applicable Provisions and Regulations

a. The "affected slab reheat furnaces" for the purpose of these unit-specific conditions, are the emission/production units as described in Conditions 7.7.1 and 7.7.2 above.

b. The affected slab reheat furnaces are subject to 35 IAC 212.458(b)(10) and (c), which provide that no person shall cause or allow emissions of PM_{10}, other than that of fugitive particulate matter, into the atmosphere to exceed 38.7 ng/J (0.09 lbs/mmBtu) of heat input from the slab furnaces at steel plants in the vicinity of Granite City during any one hour period, provided however that this limit shall not apply if there are no visible emissions, except if a stack test is performed, the absence of visible emissions is not a defense to a finding of violation.

c. The affected slab reheat furnace #4 is subject to 35 IAC 212.321(a), which provides that:

No person shall cause or allow the emission of particulate matter into the atmosphere in any one hour period from any new process emission unit, which either alone or in combination with the emission of particulate matter from all other similar process emission units for which construction or modification commenced on or after April 14, 1972, at a source or premises, exceeds the allowable emission rates specified in 35 IAC 212.321(c) (See also Attachment 2) [35 IAC 212.321(a)].

d. The affected slab reheat furnaces #1, #2 and #3 are subject to 35 IAC 212.322(a), which provides that:

No person shall cause or allow the emission of particulate matter into the atmosphere in any one hour period from any process emission unit for which construction or modification commenced prior to April 14, 1972, which, either alone or in combination with the emission of particulate matter from all other similar existing process emission units at a source or premises, exceeds the allowable emission rates specified in 35 IAC 212.322(c) (See also Attachment 2) [35 IAC 212.322(a)].

e. Pursuant to 35 IAC 214.301, the affected slab reheat furnaces shall comply with the following: no person shall cause or allow the emission of sulfur dioxide into the atmosphere from any process emission source to exceed 2000 ppm.

f. Pursuant to 35 IAC 212.123(a), the affected slab reheat furnaces shall comply with the following: no person shall cause or allow the emission of smoke or other particulate matter, with an opacity greater than 30 percent, into the atmosphere from any emission unit other than those emission units subject to the requirements of 35 IAC 212.122, except as allowed by 35 IAC 212.123(b) and 212.124.

g. Pursuant to 35 IAC 212.458(b)(7) and (c), the affected slab reheat furnaces shall comply with the following:

No person shall cause or allow emissions of PM_{10}, other than that of fugitive particulate matter, into the atmosphere to exceed the following limits during any one hour period:

22.9 mg/scm (0.01 gr/scf) from any process emissions unit provided however that this limit shall not apply if there are no visible emissions, except if a stack test is performed, the absence of visible emissions is not a defense to a finding of violation [35 IAC 212.458(b)(7) and (c)].

7.7.4 Non-Applicability of Regulations of Concern

a. The emission limitations of 35 IAC 212.324 are not applicable to the affected slab reheat furnaces, because

they are subject to a specific emissions standard or limitation contained in 35 IAC Part 212 Subpart R, pursuant to 35 IAC 212.324 (a)(3).

b. The affected slab reheat furnaces are not subject to 40 CFR Part 63 Subpart FFFFF, Integrated Iron and Steel Manufacturing, because reheat furnaces are not covered by this NESHAP [see 40 CFR 63.7782(c)].

c. This permit is issued based on the Permittee not being subject to the work practice and recordkeeping requirements of 35 IAC 212.324(f) because the affected slab reheat furnaces do not use air pollution control equipment for particulate matter.

7.7.5 Startup Provisions

a. Pursuant to 35 IAC 201.149 and Part 201 Subpart I, subject to the following terms and conditions for affected slab reheat furnaces, the Permittee is authorized to violate the applicable opacity standards in 35 IAC 212.123(a) of Condition 7.7.3(f) during startup.

Note: This authorization is provided because the Permittee applied for such authorization in its CAAPP application, generally describing the efforts that will be used "…to minimize startup emissions, duration of individual starts, and frequency of startups".

i. This authorization does not relieve the Permittee from the continuing obligation to demonstrate that all reasonable efforts are made to minimize startup emissions, duration of individual startups and frequency of startups.

ii. The Permittee shall conduct startup of the affected slab reheat furnaces in accordance with written procedures prepared by the Permittee and maintained at the source (see Condition 7.7.10(d)(i)) for the affected slab reheat furnaces, that are specifically developed to minimize emissions from startups and that include, at a minimum:

A. A review of the operational condition of the affected reheat furnaces prior to initiating startup of the furnaces;

B. Initiation of startups to provide adequate time to implement the established startup procedures;

C. Sequential startup of the burners in the different zones of each furnace; and

D. Temperature levels achieved during startup.

iii. The Permittee shall fulfill applicable recordkeeping of Condition 7.7.10(d).

iv. The Permittee shall fulfill applicable reporting of Condition 5.10.5-1.

b. As provided by 35 IAC 201.265, an authorization in a permit for excess emissions during startup does not shield a Permittee from enforcement for any violation of applicable emission standard(s) that occurs during startup and only constitutes a prima facie defense to such an enforcement action provided that the Permittee has fully complied with all terms and conditions connected with such authorization.

7.7.6 Control Requirements and Work Practices

a. Pursuant to Permit 06070022, the affected slab reheat furnaces shall be equipped, operated, and maintained with low NO_x burners. The low NO_x burners shall be operated and maintained in conformance with good air pollution control practices. These low-NO_x burners shall be operated in the following zones of the affected slab reheat furnace [T1R]:

i. Slab reheat furnaces #1 through #3: heat and intermediate zones; and

ii. Slab reheat furnace #4: heat zone.

b. The affected slab reheat furnaces are allowed to burn natural gas and coke oven gas only as a fuel [Section 39.5(7)(a)of the Act].

7.7.7 Operating and Emission Limits

The following operating and emission limits are established for the affected slab reheat furnaces [06070022, T1]:

a. Operation of the affected slab reheat furnaces shall not exceed the following limits:

Emission Unit	Total Gas Usage (mmBtu/year)	COG Usage (mmBtu/year)
Slab Reheat Furnace #3	1,654,304	1,187,790
Slab Reheat Furnace #4	2,206,238	1,544,367
Total (Furnaces 1-4)	7,169,150	2,421,388

b. Emissions of NO_x from the affected slab reheat furnaces shall not exceed the following limits:

Furnace	Limit (Lbs/mmBtu)
Slab Reheat Furnace #1	0.150
Slab Reheat Furnace #2	0.150
Slab Reheat Furnace #3	0.264
Slab Reheat Furnace #4	0.283

c. Emissions of NO_x from the affected slab reheat furnaces (combined) shall not exceed 73 tons/month and 724.09 tons/year.

d. Compliance with above annual limits shall be determined from a running total of 12 months of data.

7.7.8 Testing Requirements

a. Pursuant to Section 39.5(7)(d) and (p) of the Act, the Permittee shall conduct a performance test on each affected slab reheat furnace within 18 months of the effective date of this permit condition and furnish the Illinois EPA a written report of the results of such test(s).

i. These tests shall be conducted while the reheat furnace is firing COG at the maximum level in the normal mix of fuel for the furnace.

ii. The following methods and procedures shall be used for testing of emissions, unless another method is approved by the Illinois EPA: Refer to 40 CFR 60, Appendix A, for USEPA test methods.

Location of Sample Points	USEPA Method 1
Gas Flow and Velocity	USEPA Method 2
Flue Gas Weight	USEPA Method 3
Moisture	USEPA Method 4
NO_x	USEPA Method 7E or 19

b. The Permittee shall conduct tests for PM/PM_{10} and NO_x emissions of the affected reheat furnaces upon written request from the Illinois EPA, for furnace(s) and fuel mix, as specified in the request. This testing shall be completed within 90 days of the request of by such later date agreed to by the Illinois EPA. For NO_x, this testing shall be conducted in accordance with Condition 7.7.8(a)(i). For PM/PM_{10}, testing shall be conducted using USEPA Test Methods as specified in 35 IAC 212.108(a).

c. For all required emission tests, the Permittee shall conduct opacity observations in accordance with USEPA Method 9 during each run and report the results in the test report. The duration of observations for each run shall be 30-minutes unless visible emissions are not observed during

the first 12 minutes. Notwithstanding the above, if weather conditions during the period of testing are not suitable for conducting opacity observations, observations may be conducted within 48 hours of the time of testing, in which case, the duration of observations shall be 3 hours unless visible emissions are not observed during the first 36 minutes of observations.

d. With the reports for all emission testing, the Permittee shall also provide the sulfur content of the COG being combusted during the period of testing, as measured by the monitoring system for COG, and sulfur content of the mixed fuel combusted during the period of testing, with supporting calculations.

e. For this emission testing, test notifications and reporting shall be done by the Permittee in accordance with Conditions 8.6.2 and 8.6.3 of this permit.

7.7.9 Monitoring Requirements

The affected slab reheat furnaces are subject to the following monitoring requirements, pursuant to Sections 39.5(7)(a) and (d) of the Act:

a. The Permittee shall conduct opacity observations for each affected slab reheat furnace on a semi-annual basis, in accordance with USEPA Method 9, for a minimum of 30 minutes per furnace, unless no visible emissions are observed during the first 12 minutes of observations. The results of these observations shall be reported to the Illinois EPA within 45 days after each observation is conducted.

b. Unless annual performance tests or continuous monitoring for emissions of NO_x is being conducted for an affected slab reheat furnace pursuant to 35 IAC Part 217, Subpart D, the Permittee shall perform combustion evaluations/inspections of the burners on each affected slab reheat furnace on a regular basis, including inspections of the various components of the burner for their condition and proper functioning, and diagnostic measures of the NO_x concentration in the exhaust of the furnace before and after performance evaluation. These inspections/evaluations shall be conducted on a semi-annual basis if accommodated by the schedule for maintenance outages on an affected furnace, and otherwise on at least an annual basis.

7.7.10 Recordkeeping Requirements

The Permittee shall maintain records of the following items for the affected slab reheat furnaces, pursuant to Sections 39.5(7)(a) and (e) of the Act:

a. i. Records for heat input:

A. For COG (mmBtu/month and mmBtu/year) for all affected slab reheat furnaces (combined) and for furnaces #3 and #4 (individually).

B. For natural gas (mmBtu/month and mmBtu/year) for all affected slab reheat furnaces (combined) and for furnaces #3 and #4 (individually).

ii. Records for the amount for each type of fuel used (mmscf/mo).

b. A log or other records that will serve to identify the fuel or fuels being fired during each hour in each affected reheat furnace:

i. For furnaces # 1, 2 and 3, whether natural gas or COG is being fired.

ii. For furnace #4, the setting for the mix of natural gas and COG that is being fired.

c. Records for all emission tests and opacity observations for the affected slab reheat furnaces.

d. Records for Startups of Affected Slab reheat furnaces, pursuant to Section 39.5(7)(b) of the Act

i. The Permittee shall maintain startup procedures for each affected slab reheat furnace, as required by Condition 7.7.5(a)(ii).

ii. The Permittee shall maintain the following records for each startup of an affected furnace:

A. Date, time and duration of the startup.

B. A description of the startup and reason(s) for the startup.

C. Whether a violation of an applicable standard may have occurred during startup accompanied by the information in Condition 7.7.9(d)(iv) if a violation may have or did occur.

D. Whether the established startup procedures, maintained above, were followed accompanied by the information in Condition 7.7.9(d)(iii) if there were departure(s) from those procedures.

iii. If the established startup procedures were not followed during a startup, the Permittee shall maintain the following records:

A. A description of the departure(s) from the established procedures.

B. The reason(s) for the departure(s) from the established procedures.

C. An explanation of the consequences of the departure(s) for emissions, such as whether the departure(s) prolonged the startup or resulted in additional emissions, and if so,

1. The actions taken to minimize emissions and the duration of the startup; and

2. An explanation whether similar incidents might be prevented in the future and if so, the corrective actions taken or to be taken to prevent similar incidents.

iv. If a violation did or may have occurred during a startup, the Permittee shall maintain the following records:

A. Identification of the applicable standard(s) that were or may have been violated.

B. An explanation of the nature of such violation(s), including the magnitude of such excess emissions.

C. A description of the actions taken to minimize the magnitude of emissions and duration of the startup.

D. An explanation whether similar incidents could be prevented or ameliorated in the future and if so, a description of the actions taken or to be taken to prevent similar incidents in the future.

e. A maintenance and repair log for each affected slab reheat furnace, listing each activity performed with date.

f. The following records related to the emissions of PM/PM_{10}, SO_2, and NO_x from the affected slab reheat furnaces:

i. A file containing the emission factors used by the Permittee to determine emissions of pollutants other than SO_2 from the affected slab reheat furnaces, with supporting documentation. These records shall be reviewed and updated by the Permittee as necessary to assure that the emission factors that it uses to determine emissions of the affected furnace do not understate actual emissions. These records shall be

prepared and copies sent to the Illinois EPA in accordance with Condition 5.9.6(c).

ii. If different emission factors are used for furnaces #1 and #2, records for the individual usage of fuels by these furnaces (scf/month and scf/year).

iii. Records of emissions of PM/PM_{10}, SO_2, NO_x from the affected slab reheat furnaces (tons/month and tons/year), with supporting calculations.

7.7.11 Reporting Requirements

a. i. Pursuant to Section 39.5(7)(f)(ii) of the Act, the Permittee shall promptly notify the Illinois EPA, Air Compliance Section, within 30 days of deviations by the affected slab reheat furnaces from applicable requirements, as follows:

A. Requirements in Condition 7.7.3(b) through (f).

B. Requirements in Condition 7.7.6.

C. Requirements in Condition 7.7.7.

ii. All such deviations shall be summarized and reported as part of the semiannual monitoring report required by Condition 8.6.1.

b. The Permittee shall notify the Illinois EPA, Air Compliance Section, of all other deviations as part of the semiannual monitoring reports required by Condition 8.6.1.

c. All deviation reports described in Condition 7.7.11 above shall contain the following:

i. Date, time and duration of the deviation;

ii. Description of the deviation;

iii. Probable cause of the deviation; and

v. Any corrective action or preventive measures taken.

d. Reporting on the State startup authorization shall be performed in accordance with Condition 5.10.5-1.

7.7.12 Operational Flexibility/Anticipated Operating Scenarios

No operational flexibility has been established for the affected slab reheat furnaces.

7.7.13 Compliance Procedures

For affected slab reheat furnaces, compliance with the applicable standards of Condition 7.7.3 and with the operating and emission limits of Condition 7.7.7 is addressed by the work practices, testing, monitoring, recordkeeping and reporting requirements in Section 7.7 of this permit.

7.7.14 State-Only Conditions

Pursuant to 35 IAC 217.150, 217.152, and 217.160, by the applicable compliance date for 35 IAC Part 217 Subparts D and I, the Permittee shall comply with applicable requirements of these rules for the affected slab reheat furnaces, including:

a. Certifying to the Illinois EPA that the affected slab reheat furnaces will be in compliance with the applicable emission limitation(s) of 35 IAC 217.244(a) by the applicable compliance date.

b. Operation of each affected slab reheat furnaces in a manner consistent with good air pollution control practices to minimize NO_x emissions,

c. Compliance with the applicable NO_x emission limitation(s) in accordance with 35 IAC 217.154 or 217.157.

d. Compliance with the applicable monitoring, recordkeeping and reporting requirements in accordance with 35 IAC 217.157(b) and 217.156.

7.8 Finishing Operations

7.8.1 Description

Pickling Line:

Coils are processed in this unit to clean the steel and prepare it for other treatments such as cold rolling or galvanizing. At the start of the pickling line, the coils are unwound and the leading edge of each coil is trimmed off square. The leading edge of each coil is then spot (resistance) welded to the trailing edge of the previous coil. By joining the coils in this manner the pickling line runs a continuous ribbon of steel and does not need to be taken out of production to reload. After the steel coils are joined the steel is passed through an acid bath. This acid bath consists of four dip tanks arranged in series and uses a solution of hydrochloric acid and water to clean the surfaces of the steel sheet. A scrubbing system with mist eliminator is used to control hydrogen chloride emissions from this process. When the steel comes out of the fourth acid dip tank it is passed through a cold rinse tank in which cool water is used to rinse the acid off of the steel. The next step is to pass the steel through a hot rinse tank. In this tank hot water is used to rinse any remaining acid away from the steel and to raise the temperature of the steel to speed the drying process. The steel is then passed through a hot air dryer to complete the drying process. The steel that is to be shipped is coated with oil immediately prior to recoiling to inhibit corrosion. In the final step of the pickling process, the steel is recoiled.

Galvanizing Line Steel Preparation:

Steel coils that are to be galvanized in this unit are first joined end to end by spot (resistance) welding the leading edge of one coil to the trailing edge of another coil. The steel is then passed through a rinse station where it is rinsed with either a weak alkaline solution or a weak acid solution. The purpose of this rinse is to clean the steel and break down any oils that may be on the surfaces. The emissions from this unit are exhausted to a packed column wet scrubber. After cleaning and rinsing the steel is dried by a steam dryer.

Galvanizing Line Finishing Processes:

After the steel is coated with zinc, it is cooled and then dipped into a "Chem-treat" bath. This non-organic chemical puts a layer of rust-preventative on the steel. The steel is coated with oil to protect the surfaces, recoiled, and sprayed with edge sealer (oil) to protect the edges of the steel. The oil applied to the steel is a light petroleum based oil used to inhibit corrosion. Edge sealers are oils used to protect the edges of the steel and inhibit corrosion.

Note: This narrative description is for informational purposes only and is not enforceable.

7.8.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Date Constructed	Emission Control Equipment
Finishing Operations	HCL Pickling Line	Pre-1973	Two Fume Scrubbers
	Galvanizing Line #7A; the line is comprised of the following significant components: • Cleaner section • Natural Gas furnace • Galvanizing pot • Miscellaneous heaters	Pre-1973	Fume Scrubber
	Galvanizing Line #8; the line is comprised of the following significant components: • Cleaner Section (with fume scrubber) • Natural gas fired Furnace (with NO_x catalytic converter) • 2 Galvanizing Pots • Space Heaters • Miscellaneous Heaters • Melting Kettle Building and Storage Areas Heaters	1995	Fume Scrubber; NO_x catalytic converter
	Coating Operations	Pre-1973	None

7.8.3 Applicable Provisions and Regulations

a. The "affected finishing operations" for the purpose of these unit-specific conditions, are the emission units described in Conditions 7.8.1 and 7.8.2.

b. Pursuant to 35 IAC 212.458(b)(7) and (c), the affected finishing operations shall comply with the following:

No person shall cause or allow emissions of PM_{10}, other than that of fugitive particulate matter, into the atmosphere to exceed the following limits during any one hour period:

22.9 mg/scm (0.01 gr/scf) from any process emissions unit provided however that this limit shall not apply if there are no visible emissions, except if a stack test is performed. The absence of visible emissions is not a defense to a finding of violation [35 IAC 212.458(b)(7) and (c)]

c. The following process emission units in the affected finishing operation constructed or modified prior to April 14, 1972 are subject to IAC 212.322(a): cleaner section and galvanizing pot of Galvanizing Line #7A and coating operations. No person shall cause or allow the emission of particulate matter into the atmosphere in any one hour period from any process emission unit for which construction or modification commenced prior to April 14, 1972, which, either alone or in combination with the emission of particulate matter from all other similar process emission units at a source or premises, exceeds the allowable emission rates specified in subsection (c) of 35 IAC 212.322 (see also Attachment 2) [35 IAC 212.322(a)].

d. The following process emission units in the affected finishing operation constructed or modified on or after April 14, 1972 are subject to IAC 212.321(a): cleaner section, two galvanizing pots and the melting kettle of Galvanizing Line #8. No person shall cause or allow the emission of particulate matter into the atmosphere in any one hour period from any process emission unit for which construction or modification commenced on or after April 14, 1972, which, either alone or in combination with the emission of particulate matter from all other similar process emission units at a source or premises, exceeds the allowable emission rates specified in subsection (c) of 35 IAC 212.321 (see also Attachment 2) [35 IAC 212.321(a)].

e. Coating operations performed as part of the affected finishing operations are subject to 35 IAC 219.204, with which the Permittee must comply by application of compliant coating as established by 35 IAC 219.204(d) for coil coating:

   i. No owner or operator of an affected coil coating operation shall apply at any time any coating in which the VOM content exceeds the following emission limitations. The following emission limitation is expressed in units of VOM per volume of coating (minus water and any compounds which are specifically exempted from the definition of VOM) as applied at each coating applicator:

kg/l	lb/gal
0.20	1.7

ii. Compounds which are specifically exempted from the definition of VOM should be treated as water for the purpose of calculating the "less water" part of the coating composites.

f. The HCL pickling line operates as a part of the affected finishing operations and is subject to 40 CFR Part 63 Subpart CCC "National Emission Standards for Hazardous Air Pollutants for Steel Pickling—HCl Process Facilities and Hydrochloric Acid Regeneration Plants". Specific requirements of Subpart CCC are set forth later in this subsection.

g. Pursuant to 35 IAC 212.123(a), no person shall cause or allow the emission of smoke or other particulate matter, with an opacity greater than 30 percent, into the atmosphere from any emission unit other than those emission units subject to the requirements of 35 IAC 212.122, except as allowed by 35 IAC 212.123(b) and 212.124.

7.8.4 Non-Applicability of Regulations of Concern

a. The emission limitations of 35 IAC 212.324 are not applicable to any emission unit subject to a specific emissions standard or limitation contained in 35 IAC Part 212 Subpart R, pursuant to 35 IAC 212.324 (a)(3).

b. This permit is issued based on the coating operations operated as a part of the affected finishing operations not being subject to 40 CFR 63 Subpart SSSS "National Emission Standards for Hazardous Air Pollutants: Surface Coating of Metal Coil" pursuant to the definition of coating used by Subpart SSSS (Decorative, protective, or functional materials that consist only of solvents, protective oils, acids, bases, or any combination of these substances are not considered coatings for the purposes of Subpart SSSS).

c. This permit is issued based on the coating operations operated as a part of the affected finishing operations not being subject to 40 CFR 63 Subpart MMMM "National Emission Standards for Hazardous Air Pollutants for Surface Coating of Miscellaneous Metal Parts and Products" pursuant to definition of coating used by Subpart MMMM (Decorative, protective, or functional materials that consist only of solvents, protective oils, acids, bases, or any combination of these substances are not considered coatings for the purposes of Subpart MMMM).

d. The pickling operations are not subject to 35 IAC 212.321 or 212.322 pursuant to 35 IAC 266.190.

7.8.5-1 NESHAP Emission Standards

a. The affected pickling line is subject to 40 CFR 63.1157(a), which provides that no owner or operator of an existing affected continuous or batch pickling line at a steel pickling facility shall cause or allow to be discharged into the atmosphere from such line:

i. Any gases that contain HCl in a concentration in excess of 18 parts per million by volume (ppmv); or

ii. HCl at a mass emission rate that corresponds to a collection efficiency of less than 97 percent.

b. This standard shall apply at all times, including startup, shutdown and malfunction/breakdown, as 40 CFR 63.6(f) has been vacated.

7.8.5-2 NESHAP Work Practices (Galvanizing Lines)

Affected Galvanizing Furnaces #7A and #8 as well as miscellaneous heaters on Galvanizing Line #8 are subject to the NESHAP, 40 CFR Part 63, Subpart DDDDD. Pursuant to 40 CFR 63.7499, these affected units are in the Gas 1 Subcategory for purposes of this NESHAP, as they only burn natural gas.

a. Beginning on of the compliance date of this NESHAP, the Permittee must conduct a tune-up on each affected unit as follows:

i. For Galvanizing Furnaces #7A and #8, the Permittee must conduct a tune-up of each furnace annually [40 CFR 63.7540(a)(10)].

ii. For miscellaneous heaters on galvanizing line #8, the Permittee must conduct a biennial tune-up of each heater [40 CFR 63.7540(a)(11)].

iii. If a unit is not operating on the required date for a tune-up, the tune-up must be conducted within one week of startup [40 CFR 63.7540(a)(12)].

b. Pursuant to 40 CFR 63.7540(a)(10), each required tune-up shall consist of the following:

i. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the burner inspection may be delayed until the next scheduled unit shutdown, but each burner must be inspected at least once every 36 months) [40 CFR 63.7640(a)(10)(i)];

ii. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available [40 CFR 63.7640(a)(10)(ii)];

iii. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly [40 CFR 63.7640(a)(10)(iii)];

iv. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available [40 CFR 63.7640(a)(10)(iv)];

v. Measure the concentrations in the effluent stream of CO in parts per million, by volume (ppmv), and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made) [40 CFR 63.7640(a)(10)(v)].

c. Pursuant to 40 CFR 63.7640(a)(10)(vi), the Permittee shall maintain on-site and submit, if requested by the Illinois EPA, an annual report containing the following for the required tune-ups:

i. The concentrations of CO in the effluent stream in ppmv, and oxygen in volume percent, measured before and after the adjustments of the furnace;

ii. A description of any corrective actions taken as a part of the combustion adjustment; and

iii. The type and amount of fuel used over the 12 months prior to the annual adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel use by each unit.

7.8.6 Control Requirements and Work Practices

a. Hydrochloric acid storage vessels. The owner or operator of an affected vessel shall provide and operate, except during loading and unloading of acid, a closed-vent system for each vessel. Loading and unloading shall be conducted either through enclosed lines or each point where the acid is exposed to the atmosphere shall be equipped with a local fume capture system, ventilated through an air pollution control device [40 CFR 63.1159(b)].

Note: HCL storage tanks associated with the affected pickling line are insignificant activities addressed in

Section 3.0 of this permit. Loading and unloading is currently conducted through enclosed lines.

b. Maintenance requirements [40 CFR 63.1160(b)]

i. The Permittee shall comply with the operation and maintenance requirements prescribed under 40 CFR 63.6(e) for the HCL pickling line.

ii. In addition to the requirements specified in 40 CFR 63.6(e), the Permittee shall operate in accordance with an operation and maintenance plan that it prepares for each emission control device. Such plan shall be consistent with good maintenance practices and, for a scrubber emission control device, shall at a minimum address the following:

A. Require monitoring and recording the pressure drop across the scrubber once per shift while the scrubber is operating in order to identify changes that may indicate a need for maintenance;

B. Require the manufacturer's recommended maintenance at the recommended intervals on fresh solvent pumps, re-circulating pumps, discharge pumps, and other liquid pumps, in addition to exhaust system and scrubber fans and motors associated with those pumps and fans;

C. Require cleaning of the scrubber internals and mist eliminators at intervals sufficient to prevent buildup of solids or other fouling;

D. Require an inspection of each scrubber at intervals of no less than 3 months with:

1. Cleaning or replacement of any plugged spray nozzles or other liquid delivery devices;

2. Repair or replacement of missing, misaligned, or damaged baffles, trays, or other internal components;

3. Repair or replacement of droplet eliminator elements as needed;

4. Repair or replacement of heat exchanger elements used to control the temperature of fluids entering or leaving the scrubber; and

5. Adjustment of damper settings for consistency with the required air flow.

E. If the scrubber is not equipped with a viewport or access hatch allowing visual inspection, alternate means of inspection approved by the Administrator may be used.

F. The owner or operator shall initiate procedures for corrective action within 1 working day of detection of an operating problem and complete all corrective actions as soon as practicable. Procedures to be initiated are the applicable actions that are specified in the maintenance plan. Failure to initiate or provide appropriate repair, replacement, or other corrective action is a violation of the maintenance requirement of 40 CFR 63, Subpart CCC.

G. The owner or operator shall maintain a record of each inspection, including each item identified in 40 CFR 63.1160(b)(2)(iv), that is signed by the responsible maintenance official and that shows the date of each inspection, the problem identified, a description of the repair, replacement, or other corrective action taken, and the date of the repair, replacement, or other corrective action taken.

7.8.7 Production and Emission Limits from Permit 95010005 [T1].

a. The operation of Galvanizing Line #8 shall not exceed the following [T1]:

i. The maximum firing rate of the furnace shall not exceed 54.6 million British thermal units (mmBtu) per hour.

ii. The maximum firing rate of each of the five space heaters shall not exceed 3.44 mmBtu/hour.

iii. The total combined maximum firing rate of the building and storage area heaters shall not exceed 9.84 mmBtu/hour.

iv. The total combined natural gas usage of the 11 miscellaneous heaters shall not exceed 21,895 ft^3/hour and 191.8 million ft^3/year.

v. The operation of the melting kettle shall not exceed 32,000 tons of product/month and 384,000 tons of product/year.

b. The emissions of Galvanizing Line #8 shall not exceed the following [T1]:

i. Furnace

A. The NO_x emissions of the furnace shall not exceed 2.07 lbs/hour and 9.04 tons/year.

B. Emissions of other pollutants from the furnace shall not exceed the following limits:

Carbon Monoxide:	8.37 tons/year
Particulate Matter:	0.72 tons/year
PM_{10}:	0.72 tons/year
VOM:	0.67 tons/year
SO_2:	0.14 tons/year

ii. Five Space Heaters (total)

A. The total combined NO_x emissions of the 5 space heaters shall not exceed 1.69 lbs/hour and 7.39 tons/year.

B. Total emissions of other pollutants from the 5 space heaters shall not exceed the following limits:

Carbon Monoxide:	1.48 tons/year
Particulate Matter:	0.22 tons/year
PM_{10}:	0.22 tons/year
VOM:	0.39 tons/year
SO_2:	0.04 tons/year

iii. Drying Oven and the Building and Storage Area Heaters (total)

A. The total combined NO_x emissions of the drying oven and the building and storage area heaters shall not exceed 0.97 lbs/hour and 4.29 tons/year.

B. Total emissions of other pollutants from the drying oven and the building and storage area heaters shall not exceed the following limits:

Carbon Monoxide:	0.85 tons/year
Particulate Matter:	0.13 tons/year
PM_{10}:	0.13 tons/year
VOM:	0.22 tons/year
SO_2:	0.03 tons/year

iv. Miscellaneous Heaters (total)

A. Total combined NO_x emissions of the 11 miscellaneous heaters shall not exceed 2.19 lbs/hour and 9.60 tons/year.

B. Total combined emissions of other pollutants from the 11 miscellaneous heaters shall not exceed the following limits:

Carbon Monoxide:	1.92 tons/year
Particulate Matter:	0.29 tons/year
PM_{10}:	0.29 tons/year
VOM:	0.51 tons/year
SO_2:	0.06 tons/year

v. Cleaner Section

Emissions of particulate matter from the cleaner section, which is controlled with a fume scrubber, shall not exceed 0.24 lbs/hour and 1.06 tons/year.

vi. Melting Kettle

Particulate matter emissions from the melting kettle shall not exceed 0.16 tons/month and 1.92 tons/year.

vii. Other emission units

Emissions of NO_x, CO, PM, VOM and SO_2 from the welder, two galvanizing pots and chemical treatment tank shall not exceed negligible rates of 0.1 lb/hour and 0.44 tons/year for each pollutant from each such emission unit.

c. Compliance with annual limits shall be determined on a monthly basis from the sum of the data for the current month plus the preceding 11 months (running 12 month total) [T1].

7.8.8 Testing Requirements

a. For testing emissions of the HCl Pickling Line pursuant to 40 CFR 63, Subpart CCC:

i. The Permittee shall use the following test methods in Appendix A of 40 CFR Part 60 pursuant to 40 CFR 63.1161(d), unless an equivalent alternative measurement method is approved by the Administrator, to determine compliance under 40 CFR 63.1157(a):

A. Method 1, to determine the number and location of sampling points, with the exception that no traverse point shall be within one inch of the stack or duct wall;

B. Method 2, to determine gas velocity and volumetric flow rate;

C. Method 3, to determine the molecular weight of the stack gas;

D. Method 4, to determine the moisture content of the stack gas; and

E. Method 26A, "Determination of Hydrogen Halide and Halogen Emissions from Stationary Sources—Isokinetic Method," to determine the HCl mass flows at the inlet and outlet of a control device or the concentration of HCl discharged to the atmosphere, and also to determine the concentration of Cl_2 discharged to the atmosphere from acid regeneration plants. If compliance with a collection efficiency standard is being demonstrated, inlet and outlet measurements shall be performed simultaneously. The minimum sampling time for each run shall be 60 minutes and the minimum sample volume 0.85 dry standard cubic meters (30 dry standard cubic feet). The concentrations of HCl and Cl_2 shall be calculated for each run as follows:

C_{HCl} (ppmv) = 0.659 C_{HCl} (mg/dscm),
and C_{Cl2} (ppmv) = 0.339 C_{Cl2} (mg/dscm),

where C(ppmv) is concentration in ppmv and C(mg/dscm) is concentration in milligrams per dry standard cubic meter as calculated by the procedure given in Method 26A.

ii. Pursuant to 40 CFR 63.1162(a)(1), the Permittee shall conduct performance tests a minimum of once every 2 years to measure the HCl mass flows at the control device inlet and outlet or the concentration of HCL exiting the control.

iii. If any performance test shows that the HCL emission limitation is being exceeded, then the owner or operator is in violation of the emission limit.

b. Upon written request from the Illinois EPA, emission tests shall be conducted by the Permittee for the furnace, melting kettle and cleaner section (all of galvanizing line #8) to verify compliance with emission limits in Condition 7.8.7, as follows [Section 39.5(7)(d) and (p) of the Act].

i. The following USEPA test methods shall be used, unless another USEPA method is approved by the Illinois EPA.

A.	Location of Sample Points	Method 1
B.	Gas Flow and Velocity	Method 2
C.	Flue Gas Weight	Method 3
D.	Moisture	Method 4
E.	PM/PM_{10} (furnace, kettle, and cleaner section)	Methods 5, 201 or 201A
vi.	NO_x (furnace)	Method 7E or 19

ii. Observations of opacity shall be conducted during these emission tests in accordance with Method 9 and the results of these observations included in the reports for emission testing.

c. Upon written request by the Illinois EPA, the Permittee shall conduct opacity observations from any finishing operation, as specified in the request, as follows [Sections 39.5(7)(d) and (p) of the Act]:

i. These observations shall be conducted within 45 calendar days of the requires or by the date agreed upon by the Illinois EPA, whichever is later.

ii. The readings shall be performed by a qualified observer in accordance with USEPA Method 9 while the affected finishing operation is operating.

d. For this testing, test notifications and reporting shall be done by the Permittee in accordance with Conditions 8.6.2 and 8.6.3 of this permit.

7.8.9 Monitoring Requirements

a. For the affected pickling line, the Permittee shall comply with the following requirements of 40 CFR 63.1160(b)(2) and 63.1162(a)(2) Section 39.5(7)(a):

i. The Permittee shall operate, and maintain systems for the measurement and recording of the scrubber makeup water flow rate and, if required, recirculation water flow rate. These flow rates shall be monitored continuously and recorded at least once per shift while the scrubber is operating.* If operation of the wet scrubber results in excursions of scrubber makeup water flow rate and recirculation water flow rate less than the minimum values established, the Permittee shall initiate corrective action within 1

working day as specified by the maintenance requirements in 40 CFR 63.1160(b)(2). Failure to initiate or provide appropriate repair, replacement, or other corrective action is a violation of the maintenance requirement of 40 CFR 63.1160(b)(2).

ii. The Permittee shall monitor and record the pressure drop across the scrubber once per shift* while the scrubber is operating in order to identify changes that may indicate a need for maintenance. The Permittee shall initiate procedures for corrective action within 1 working day of detection of an operating problem and complete all corrective actions as soon as practicable. Procedures to be initiated are the applicable actions that are specified in the maintenance plan. Failure to initiate or provide appropriate repair, replacement, or other corrective action is a violation of the maintenance requirement of 40 CFR 63.1160(b)(2).

* See also Condition 7.8.9(g)

iii. Corrective action as referenced in Condition 7.8.9(a)(i) and (ii) and as prescribed by "the Operation and Maintenance Plan" required by Condition 7.8.6(b)(ii), shall consist of the following:

A. Notify the pickle line shift manager or cold mill shift manager as soon as practicable but not later than the end of the shift of the operating problem detected.

B. The pickle line shift manager or cold mill shift manager shall notify the mechanical or electrical shift manager no later than the end of the shift.

C. Any of the above shift managers shall investigate the nature of the operating problem and implement corrective actions, such as manufacturer's recommended maintenance on:

1. Pumps;

2. Exhaust systems;

3. Fans and motors;

4. Clean scrubber internals and mist eliminators to remove buildup of solids or other fouling.

D. The pickle line or cold mill shift manager shall complete an upset conditions report upon completion of corrected action.

b. Pursuant 40 CFR 63.1162(a)(4), failure to record each of the operating parameters (scrubber makeup water flow rate and recirculated water flow rate) is a violation of the monitoring requirements of 40 CFR 63 Subpart CCC.

c. Pursuant to 40 CFR 63.1162(a)(5), each monitoring device shall be certified by the manufacturer to be accurate to within 5 percent and shall be calibrated in accordance with the manufacturer's instructions but not less frequently than once per year.

d. Pursuant to 40 CFR 63.1161(b), the Permittee may reestablish compliant operating parameter values as part of any performance test that is conducted subsequent to the initial test or tests.

e. Pursuant to 40 CFR 63.1160(b)(2)(ii) through (iv), the Permittee shall conduct the following maintenance requirements:

   i. Cleaning of the scrubber internals and mist eliminators at intervals sufficient to prevent buildup of solids or other fouling;

   ii. Inspect each scrubber at intervals of no less than 3 months with:

      A. Cleaning or replacement of any plugged spray nozzles or other liquid delivery devices;

      B. Repair or replacement of missing, misaligned, or damaged baffles, trays, or other internal components;

      C. Repair or replacement of droplet eliminator elements as needed;

      D. Repair or replacement of heat exchanger elements used to control the temperature of fluids entering or leaving the scrubber; and

      E. Adjustment of damper settings for consistency with the required air flow.

f. The owner or operator of an affected hydrochloric acid* storage vessel shall inspect each vessel semiannually to determine that the closed-vent system and either the air pollution control device or the enclosed loading and unloading line, whichever is applicable, are installed and operating when required [40 CFR 63.1162(c)].

   * See also Condition 7.8.9(g)

g. Notwithstanding the requirements of 40 CFR 63, Subpart CCC, the Permittee shall:

i. Record monitored operating data for each scrubber at least twice per shift and initiate corrective action for the scrubber if any recorded data indicates an operating problem with a scrubber;

ii. Inspect the affected HCL storage vessels on at least a quarterly basis to confirm compliance.

h. Testing for VOM content of coatings shall be performed as follows [35 IAC 219.105(a) and 219.211(a) and Section 39.5(7)(b) of the Act]:

i. Upon written request by the Illinois EPA, the VOM content of specific coatings used by the coating operations shall be determined according to USEPA Reference Method 24 of 40 CFR 60 Appendix A and the procedures of 35 IAC 219.105(a) and 219.211(a); or

ii. This testing may be performed by the supplier of a material provided that the supplier provides appropriate documentation for such testing to the Permittee and the Permittee's records directly reflect the application of such materials.

i. Pursuant to Sections 39.5(7)(a) and (d) of the Act, the Permittee shall measure or monitor the pressure differential and scrubbant flow rate on the fume scrubbers controlling the cleaner sections on Galvanizing Lines #7A and #8, as follows:

i. The pressure differential shall be determined in inches of water column.

ii. Scrubbant flow rate shall be determined in gallons per minute (gpm).

iii. Pressure differential and scrubbant flow rate shall be recorded at least once per shift if data is not automatically recorded.

j. Pursuant to Sections 39.5(7)(a) and (d) of the Act, the Permittee shall operate instrumentation for the #8 Galvanizing Furnace for the NO_x concentration (ppm) in the flue gas exhaust stream and the inlet temperature (°C or °F) of the associated NO_x catalytic converter, as follows:

i. NO_x concentration (ppm) and inlet temperature shall be recorded at least once per shift if hourly average data is not automatically recorded.

ii. The Permittee shall follow manufacturer's procedures for the operation and maintenance of the NO_x instrumentation.

7.8.10 Recordkeeping Requirements

The Permittee shall maintain records of the following items for the affected finishing operations, pursuant to Sections 39.5(7)(a) and (e) of the Act:

a. Recordkeeping required for the pickling line by the NESHAP:

i. The "general records" required by the NESHAP, as required by 40 CFR 63.10(b)(2) and 63.1165.

ii. Records of the following, as required by 40 CFR 63.1165(b), which records shall be retained for 5 years from the date of each record:

A. Scrubber makeup water flow rate and recirculation water flow rate if a wet scrubber is used;

B. Calibration and manufacturer certification that monitoring devices are accurate to within 5 percent; and

C. Each maintenance inspection and repair, replacement, or other corrective action.

iii. The Permittee shall keep the written operation and maintenance plan on record after it is developed to be made available for inspection, upon request, by the Illinois EPA for the life of the affected source or until the source is no longer subject to the provisions of 40 CFR 63 Subpart CCC. In addition, if the operation and maintenance plan is revised, the Permittee shall keep the previous (i.e., superseded) versions of the plan on record to be made available for inspection by the Illinois EPA for a period of 5 years after each revision to the plan.

iv. If the Permittee operates under manufacturer's specifications or manufacturer's instructions, such manufacturer's documentation shall be kept at the source as part of the required records.

b. Recordkeeping requirements for galvanizing lines:

Pursuant to Sections 39.5(7)(a) and (f) of the Act, the Permittee shall keep the following records for the various emission units on the galvanizing lines:

i. The following records related to the tune-ups conducted on furnaces and process heaters on the lines pursuant to 40 CFR 63.7540(a)(10):

A. Records for each tune-up that include the following: Date and time tune-up was conducted and responsible person; Identification of the unit; Summary of inspections performed and required maintenance; Results of all calibrations performed; and CO concentrations in ppmv in the effluent stream and oxygen in volume percent, before and after the adjustments are made.

B. A copy of the manufacturers specifications for burners used for optimization of emissions and flame pattern during tune-ups.

ii. Records for emission tests, opacity observations, engineering calculations and other compliance determinations conducted for units to verify compliance with applicable standards, limitations and other requirements in Conditions 7.8.3, 7.8.6 and 7.8.7.

iii. Pursuant to 40 CFR 63.7555(h), if the Permittee uses an alternative fuel other than natural gas during a period of natural gas curtailment or supply interruption, the Permittee must keep records of the total hours per calendar year that alternative fuel is burned.

c. Recordkeeping for Galvanizing Line #8:

i. The following design and operating records for Galvanizing Line #8:

A. A file containing the rated heat input capacity of the furnace and each other fuel burning unit (mmBtu/hour), with supporting documentation.

B. Records of monthly and annual natural gas usage (mmscf/mo and mmscf/yr) for the furnace and other fuel burning units on the line.

ii. For the melting kettle, the following records:

A. Records of production (tons of product per month and year).

B. A file containing the emission factor used by the Permittee to calculate PM emissions from the kettle, with supporting documentation, which file shall be reviewed and updated if needed when new emission data become available

to assure that the factor does not understate actual PM emissions.

C. Records for actual PM emissions (lbs/month and tons/year), with supporting calculations.

iii. For the furnace and associated catalytic converter, the following records:

A. Engineering calculations for typical and maximum hourly NO_x emissions before and after control by catalytic converter (lbs/hour), with supporting documentation for the controlled emission rate from the furnace.

B. The normal range of operating parameters (inlet temperature and NO_x concentration in the exhaust stream) for the catalytic converter.

C. An operating log or other records for the catalytic converter that include information confirming proper operation on a daily basis and provide detailed information for any upset of the catalytic converter.

D. An inspection and maintenance log or other records for the catalytic converter that identify activities performed, with date, description and the responsible individual(s).

E. Usage or purchases of reagent for the catalytic converter (pounds/year).

F. Records for actual NO_x emissions of the furnace (tons/year), with supporting calculations.

G. A file containing the emission factors used by the Permittee to calculate emissions of PM/PM_{10}, CO, VOM and SO_2 from the furnace, with supporting documentation, and either engineering calculations for the maximum annual emissions of these pollutants (tons/year) or records of actual emissions of these pollutants (tons/year) to verify compliance with applicable limits.

iv. For the various emission units that combust fuel on the line, the following records:

A. A file containing engineering calculations for the maximum hourly emissions of NO_x (lbs/hour) from each unit or group of units, with supporting documentation.

B. A file containing the emission factors used by the Permittee to calculate emissions from these units, with supporting documentation, and either engineering calculations for the maximum annual emissions of NO_x and other pollutants (tons/year) from each unit or group of units or records of actual emissions(tons/year) to verify compliance with applicable limits.

v. For the cleaner section, the following records:

A. Engineering calculations for typical and maximum hourly PM emissions before and after control by the scrubber (lbs/hour), with supporting documentation for the controlled emission rate from the unit.

B. The normal range of operating parameters of the scrubber.

C. An operating log or other records for the scrubber that include information confirming proper operation on a daily basis and provide detailed information for any upset of the scrubber.

D. An inspection and maintenance log or other records for the scrubber that identify activities performed, with date, description and the responsible individual(s).

E. Records for actual PM emissions (tons/year), with supporting calculations.

vi. A. The records required by Conditions 7.8.10(c)(ii)(B), (c)(iii)(G) and (c)(iv)(B) shall be prepared and copies sent to the Illinois EPA in accordance with Condition 5.9.6(c).

B. Copies of the initial records required by Conditions 7.8.10(c)(iii)(A), (c)(iv)(A) and (c)(v)(A) shall be sent to the Illinois EPA within 45 days of the effective date of these conditions. Copies of revisions to these conditions shall be sent to the Illinois EPA in accordance with Condition 5.9.6(c)(ii).

d. Recordkeeping for the coating operations:

i. Records for coating usage (gal/mo and gal/yr, by coating or category of coating).

ii. Records of the VOM content of each coating or category of coating as applied (pounds/gallon, less exempt compounds), with supporting documentation.

iii. Records for testing or analysis conducted for the VOM content of coatings (pounds/gallon, less exempt compounds) that include identification of the tested coating(s), the results of the analysis, documentation for the analysis methodology, and identification of the person or party that performed the analysis.

7.8.11 Reporting Requirements

a. i. Pursuant to Section 39.5(7)(f)(ii) of the Act, the Permittee shall promptly notify the Illinois EPA, Air Compliance Section, within 30 days of deviations by the affected finishing operations from applicable requirements unless a NESHAP standard specifies a different time frame, as follows:

A. Requirements in Condition 7.8.3(b) through (e).

B. Requirements in Condition 7.8.5-1.

C. Requirements in Condition 7.8.6.

D. Requirements in Condition 7.8.7.

ii. All such deviations shall be summarized and reported as part of the semiannual monitoring report required by Condition 8.6.1.

iii. The Permittee shall notify the Illinois EPA of all other deviations as part of the semiannual monitoring reports required by Condition 8.6.1.

iv. All deviation reports required by Condition 7.8.11(a) above shall contain the following:

A. Date, time and duration of the deviation;

B. Description of the deviation;

C. Probable cause of the deviation; and

D. Any corrective action or preventive measures taken.

b. The Permittee shall comply with the reporting requirements of 40 CFR 63.1164, including the following:

i. Reporting results of performance tests. As required by 40 CFR 63.10(d)(2), the owner or operator of an affected source shall report the results of any

performance test as part of the notification of compliance status required in 40 CFR 63.1163.

ii. Progress reports. The owner or operator of an affected source who is required to submit progress reports under 40 CFR 63.6(i) shall submit such reports to the Administrator (or the State with an approved permit program) by the dates specified in the written extension of compliance.

iii. Periodic startup, shutdown, and malfunction reports. Pursuant to 40 CFR 63.6(e), the owner or operator of an affected source shall operate and maintain each affected emission source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions at least to the level required by the standard at all times, including during any period of startup, shutdown, or malfunction. Malfunctions must be corrected as soon as practicable after their occurrence.

A. Plan. As required by 40 CFR 63.6(e)(3), the owner or operator shall develop a written startup, shutdown, and malfunction plan that describes, in detail, procedures for operating and maintaining the source during periods of startup, shutdown, or malfunction, and a program of corrective action for malfunctioning process and air pollution control equipment used to comply with the relevant standards.

B. Reports. As required by 40 CFR 63.10(d)(5)(i), if actions taken by an owner or operator during a startup, shutdown, or malfunction of an affected source (including actions taken to correct a malfunction) are consistent with the procedures specified in the startup, shutdown, and malfunction plan, the owner or operator shall state such information in a semiannual report. The report, to be certified by the owner or operator or other responsible official, shall be submitted semiannually and delivered or postmarked by the 30th day following the end of each calendar half.

C. Immediate Reports. Any time an action taken by an owner or operator during a startup, shutdown, or malfunction (including actions taken to correct a malfunction) is not consistent with the procedures in the startup, shutdown, and malfunction plan, the owner or operator shall comply with all requirements of 40 CFR 63.10(d)(5)(ii).

c. Pursuant to 35 IAC 219.211(c)(3), for the affected coating operations, the Permittee shall notify the Illinois EPA in the following instances:

i. Any record showing violation of 35 IAC 219.204 shall be reported by sending a copy of such record to the Illinois EPA within 30 days following the occurrence of the violation.

ii. At least 30 calendar days before changing the method of compliance from 35 IAC 219.204 to 35 IAC 219.205 or 219.207, the Permittee shall comply with all requirements of 35 IAC 219.211(d)(1) or (e)(1), respectively. Upon changing the method of compliance from 35 IAC 219.204 to 35 IAC 219.205 or 219.207, the Permittee shall comply with all requirements of 35 IAC 219.204(d) or (e), respectively.

d. i. If the Permittee operates a unit using a fuel other than natural gas, to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575, the Permittee must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption. The notification must include the information specified in 40 CFR 63.7545(f)(1) through (f)(5) [40 CFR 63.7545(f)].

ii. If the Permittee intends to use fuel other than natural gas and other than during a period of natural gas curtailment or supply interruption as addressed by 40 CFR 63.7545(f), the Permittee must provide 30 days prior notice of the date upon which the fuels will be switched [40 CFR 63.7545(h)].

7.8.12 Operational Flexibility/Anticipated Operating Scenarios

Operational flexibility is not set for the affected finishing operations.

7.8.13 Compliance Procedures

For affected finishing operations, compliance with the applicable standards, limitations and requirements of Conditions 7.8.3, 7.8.5 and 7.8.7 is addressed by the work practices, testing, monitoring, recordkeeping and reporting requirements in Section 7.8 of this permit.

7.8.14 State-Only Conditions

Pursuant to 35 IAC 217.150, 217.152, and 217.160, by the applicable compliance date for 35 IAC Part 217 Subparts D and I, the Permittee shall comply with applicable requirements of these rules for the affected galvanizing furnaces, including:

a. Certifying to the Illinois EPA that each affected galvanizing furnaces will be in compliance with the applicable emission limitation(s) of 35 IAC 217.244(a) by the applicable compliance date.

b. Operation of each affected galvanizing furnaces in a manner consistent with good air pollution control practices to minimize NO_x emissions.

c. Compliance with the applicable NO_x emission limitation(s) in accordance with 35 IAC 217.154 or 217.157.

d. Compliance with the applicable monitoring, recordkeeping and reporting requirements in accordance with 35 IAC 217.157(b) and 217.156.

7.9 Wastewater Treatment Plant

7.9.1 Description

Primary Wastewater Treatment System:

The system is used to treat waste process water generated in both the iron and steelworks manufacturing areas in the facility. Emissions from this system are attributed to the blast furnace (BF) clarifiers, dust ponds, BF ditch, BF lagoon, steelworks ditch, steel works lagoon, and the wastewater treatment plant, itself. The ditches are used to transfer the BF and steelworks wastewater streams to the lagoons. The wastewater treatment plant is a simple system used to remove suspended solids and breakdown organic prior to discharge.

By-Products Wastewater Treatment System:

The system is used to treat waste process water generated in the coke oven by-product plant. Waste process water from the by-products plant is piped to the by-products wastewater treatment plant. The water treated in this system is primarily made up of process wastewater used to cool the processes and equipment used in the by-products plant. The treatment process carried out consists of the use of biological activity to breakdown the organic materials contained in the waste stream.

Note: This narrative description is for informational purposes only and is not enforceable.

7.9.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Date Constructed	Emission Control Equipment
Wastewater Treatment	Equalization Tanks	N/R	None
	BFG Clarifiers		
	Aeration Basin Clarifiers		
	Lagoons		
	Sand Filters		

7.9.3 Applicable Provisions and Regulations

The "affected wastewater treatment system" for the purpose of these unit-specific conditions is the treatment systems described in Conditions 7.9.1 and 7.9.2.

7.9.4 Non-Applicability of Regulations of Concern

a. The affected wastewater treatment systems are not subject to the operating and control requirements of 40 CFR 61 Subpart FF in general and 40 CFR 61.344 or 40 CFR 61.343 in particular, as provided by 40 CFR 61.342(a). This determination is based on the amount of benzene waste

generated on site being less than 10 Mg/yr (11 ton/yr). If conditions at the facility change and the total annual benzene calculation increases to 10 Mg/yr or more, the facility will become subject to operating and control requirements of 40 CFR 61 Subpart FF and the Permittee must apply for a revision to this permit, which could affect applicable requirements for the affected wastewater treatment plant.

b. The affected wastewater treatment system is not subject to 40 CFR Part 63, Subpart QQ, National Emission Standards for Surface Impoundments. This determination is based on the applicability criteria of 40 CFR 63.940, which provides that 40 CFR 63 Subpart QQ applies to impoundments when an applicable Subpart of Parts 40 CFR 60, 61 or 63 references the use of Subpart QQ for air emission control. However, applicable Subpart FF does not reference to 40 CFR 63 Subpart QQ.

c. This permit is issued based on the affected wastewater treatment system not being subject to the applicable requirements of 35 IAC 219.301 because the affected plant does not emit photochemically reactive organic material as defined in 35 IAC 211.4690.

7.9.5 Control Requirements and Work Practices

Control requirements and work practices are not set for the affected wastewater treatment systems.

7.9.6 Production and Emission Limitations

The production and emission limits are not set for the affected wastewater treatment systems.

7.9.7 Testing Requirements

Testing requirements are not set for the affected wastewater treatment systems.

7.9.8 Monitoring Requirements

If operation(s) at the facility change, the Permittee shall evaluate whether the change affects the wastewater treatment systems such that it become subject to the requirements of 35 IAC 219.301 and must apply for a revision of this permit.

7.9.9 Recordkeeping Requirements

No recordkeeping requirements are established at this time.

7.9.10 Reporting Requirements

a. Pursuant to Section 39.5(7)(f)(ii) of the Act, the Permittee shall promptly notify the Illinois EPA, Air Compliance Section, within 30 days if the following occurs:

i. The affected wastewater treatment systems become subject to the control requirements of 40 CFR 61 Subpart FF;

ii. The affected wastewater treatment system become subject to 35 IAC 219.301.

b. The notifications described in Condition 7.9.10 above shall contain the following:

i. Date of applicability;

ii. Emission units(s)/operation involved; and

iii. Method by which compliance would be demonstrated.

7.9.11 Operational Flexibility/Anticipated Operating Scenarios

Operational flexibility is not set for the affected wastewater treatment systems.

7.9.12 Compliance Procedures

Compliance procedures are not set for the affected wastewater treatment systems.

7.9.13 State-Only Conditions

State-only conditions are not established.

7.10 Boilers

7.10.1 Description

Boilers 11 and 12 are located in Boiler House 2 and are rated at 225 mmBtu/hour each. Each of these boilers are physically capable of combusting various combinations of natural gas, coke oven gas (COG) and blast furnace gas (BFG). The Permittee has a construction permit to install Flue Gas Recirculation on these boilers for control of NO_x emissions (Construction Permit 10080022).

The Permittee completed construction of a new boiler pursuant to Construction Permit 06070023. The new boiler (Power Boiler #1) is used for cogeneration, producing both electricity and process steam as it supplies high pressure steam which is sent to a steam turbine that generates electricity for use at the source. Low-pressure steam from this turbine is used for manufacturing operations at the source.

BFG is a primary fuel for this boiler. Natural gas would be used for the pilot flame and also for combustion control.

A cooling tower operates in conjunction with the new boiler and associated steam turbine.

Portable boilers not yet constructed.

Note: This narrative description is for informational purposes only and is not enforceable.

7.10.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Date Constructed	Emission Control Equipment
Boilers	Boiler House 2 Boiler 11 & 12 - 225 mmBtu/Hr each	Pre-1973	Flue Gas Recirculation (planned)
	Power Boiler #1 (nominal capacity 505 mmBtu/hour)	2009	None
Portable Boilers	Portable Boilers #1 through #4 (planned)	Planned	Low NO_x burners and Flue Gas Recirculation (planned)
Cooling Tower	Cooling Tower associated with Power Boiler #1	2009	None

7.10.3 Applicable Provisions and Regulations

a. i. The "affected boilers" for the purpose of these unit-specific conditions, are Boiler #11 and #12 and Power

Boiler #1 as described in Conditions 7.10.1 and 7.10.2.

ii. The "affected cooling tower" for the purpose of these unit-specific conditions is the unit described in Conditions 7.10.1 and 7.10.2.

b. i. Affected Boilers #11 and #12 may be subject to 40 CFR Part 63, Subpart DDDDD, NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters. For these boilers, pursuant to 40 CFE 63.7540(a), unless an affected boiler is operating as a blast furnace gas fuel-fired boiler, as defined in 40 CFR 63.7575, or is otherwise not subject to this NESHAP, beginning on the compliance date of this NESHAP for existing sources, the Permittee shall comply with each applicable emission limit, operating limit, and work practice standard in Table 2 of this NESHAP according to the methods specified in Table 8 to this NESHAP and relevant provisions in 40 CFR 63.7540(a)(1) through (11), as applicable.

ii. In particular, if affected Boiler #11 or #12 is in the Gas 2 subcategory (other gaseous fuel) pursuant to 40 CFR 63.7499, the Permittee shall comply with the following emission limits beginning on the applicable compliance date of 40 CFR 63 Subpart DDDDD, pursuant to 40 CFR 63.7500(a)(1) and Table 2 of this NESHAP:

A. Particulate Matter (PM) emissions shall not exceed 0.043 lb per mmBtu of heat input or 0.026 lb per mmBtu of steam output (3-run average).

B. Hydrogen Chloride (HCl) emissions shall not exceed 0.0017 lb per mmBtu of heat input or 0.001 lb per mmBtu of steam output.

C. Mercury (Hg) emissions shall not exceed 1.3E-05 lb per mmBtu of heat input or 7.8E-06 lb per mmBtu of steam output.*

D. CO emissions shall not exceed 9 ppm by volume on a dry basis corrected to 3 % oxygen or 0.005 lb per mmBtu of steam output.

E. Dioxin/Furans (D/F) emissions shall not exceed 0.08 ng/dscm (TEQ) corrected to 7% oxygen or 3.9E-11 (TEQ) lb per mmBtu of steam output.*

* 1.3E-05 = 0.00013
7.8E-06 = 0.0000078
3.9E-11 = 0.000000000039

c. Affected Boilers #11 and #12 shall not exceed the PM_{10} limitation of 35 IAC 212.458(b)(9):

32.25 ng/J (0.075 lbs/mmBtu) of heat input from the burning of COG.

d. The affected Power Boiler #1 is subject to the NSPS for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60 Subpart Db. (See relevant recordkeeping requirements in Condition 7.10.9.)

e. For affected boilers #11 and #12, pursuant to 35 IAC 214.421, no person shall cause or allow the emission of sulfur dioxide into the atmosphere in any one hour period from any existing fuel combustion emission source at a steel mill located in the Chicago or St. Louis (Illinois) major metropolitan area burning any solid, liquid or gaseous fuel, or any combination thereof, to exceed the allowable emission rate determined by the following equation:

$$E = S_S H_S + S_d H_d + S_R H_R + S_G H_G$$

i. Symbols in the equation mean the following:

E = allowable sulfur dioxide emission rate;

S_S = solid fuel sulfur dioxide emission standard which is applicable;

S_d = distillate oil sulfur dioxide emission standard determined from the table in 35 IAC 214.421(d) and equal to 0.46 kg/MW-hr (0.03 lb/mmBtu);

S_R = residual oil sulfur dioxide emission standard which is applicable;

S_G = maximum by-product gas sulfur dioxide emissions which would result if the applicable by-product gas which was burned had been burned alone at any time during the 12 months preceding the latest operation, on or before March 28, 1983, of an emission source using any by-product gas;

H_S = actual heat input from solid fuel;

H_d = actual heat input from distillate fuel oil;

H_R = actual heat input from residual fuel oil;

H_G = actual heat input from by-product gases, such as those produced from a blast furnace.

ii. Metric or English units may be used in the equation as follows:

Parameter	Metric	English
E	kg/hr	lbs/hr
S_S, S_R, S_G	kg/MW-hr	lbs/mmBtu
S_d	0.46 kg/MW-hr	0.3 lbs/mmBtu
H_S, H_d, H_R, H_G	MW	mmBtu/hr

f. The affected boilers are subject to 35 IAC 216.121 which provides that no person shall cause or allow the emission of carbon monoxide into the atmosphere from a fuel combustion emission unit to exceed 200 ppm, corrected to 50 percent excess air [35 IAC 216.121].

g. The affected power boiler #1 is subject to 35 IAC 212.122(a), which provides that no person shall cause or allow the emission of smoke or other particulate matter into the atmosphere from any fuel combustion emission unit for which construction or modification commenced on or after April 14, 1972, with actual heat input greater than 73.2 MW (250 mmBtu/hr), having an opacity greater than 20 percent.

h. The affected boilers #11 and #12 are subject to 35 IAC 212.123(a), which provides that no person shall cause or allow the emission of smoke or other particulate matter, with an opacity greater than 30 percent, into the atmosphere from any emission unit other than those emission units subject to 35 IAC 212.122.

i. Startup Provisions (All affected Boilers)

Pursuant to 35 IAC 201.149 and Part 201, Subpart I, subject to the following terms and conditions for affected Boilers #11, #12 and Power Boiler #1, the Permittee is authorized to violate the applicable opacity and carbon monoxide standards in 35 IAC 212.122(a), 212.123(a) and 216.121 (Conditions 7.10.3(g),(h) and (f)) during startup.

Note: This authorization is provided because the Permittee applied for such authorization in its CAAPP application, generally describing the efforts that will be used "…to minimize startup emissions, duration of individual starts, and frequency of startups."

i. This authorization does not relieve the Permittee from the continuing obligation to demonstrate that all reasonable efforts are made to minimize startup emissions, duration of individual startups and frequency of startups.

ii. The Permittee shall conduct startup of the affected boilers in accordance with the manufacturer's written instructions or other written procedures prepared by

the Permittee and maintained at the source (see Condition 7.10.9(d)(i)) for the affected boilers, that are specifically developed to minimize emissions from startups and that include, at a minimum a review of the operational condition of the affected boilers prior to initiating startup of the boiler.

iii. The Permittee shall fulfill applicable recordkeeping requirements of Condition 7.10.9(d).

iv. The Permittee shall fulfill applicable notification and reporting requirements of Condition 5.10.5-1.

v. As provided by 35 IAC 201.265, an authorization in a permit for excess emissions during startup does not shield a Permittee from enforcement for any violation of applicable emission standard(s) that occurs during startup and only constitutes a prima facie defense to such an enforcement action provided that the Permittee has fully complied with all terms and conditions connected with such authorization.

j. Malfunction or Breakdown Provisions (All affected Boilers)

Pursuant to 35 IAC 201.149 and Part 201, Subpart I, subject to the following terms and conditions, the Permittee is authorized to continue to operate affected boilers #11, #12 and Power Boiler #1 in excess of the applicable opacity and carbon monoxide standards in 35 IAC 212.122(a), 212.123(a) and 216.121 (Conditions 7.10.3(g),(h) and (f)) in the event of a malfunction or breakdown.

Note: This authorization is provided because the Permittee has applied for such authorization in its CAAPP application, generally explaining why such continued operation would be required to prevent injury to persons or severe damage to equipment, and describing the measures that will be taken to minimize emissions from any malfunctions and breakdowns.

i. This authorization only allows such continued operation as necessary to prevent injury to persons or severe damage to equipment and does not extend to continued operation solely for the economic benefit of the Permittee.

ii. Upon occurrence of excess emissions due to malfunction or breakdown, the Permittee shall as soon as practicable reduce boiler load, repair the affected boiler, remove the affected boiler from service or undertake other action so that excess emissions cease.

iii. The Permittee shall fulfill the applicable recordkeeping and reporting requirements of Condition

7.10.9(e) and Condition 5.10.5-2. For these purposes, time shall be measured from the start of a particular incident. The absence of excess emissions for a short period shall not be considered to end the incident if excess emissions resume.

iv. Following notification to the Illinois EPA (see Condition 5.10.5-2(a)(i)) of a malfunction or breakdown with excess emissions, the Permittee shall comply with all reasonable directives of the Illinois EPA with respect to such incident.

v. This authorization does not relieve the Permittee from the continuing obligation to minimize excess emissions during malfunction or breakdown. As provided by 35 IAC 201.265, an authorization in a permit for continued operation with excess emissions during malfunction and breakdown does not shield the Permittee from enforcement for any such violation and only constitutes a prima facie defense to such an enforcement action provided that the Permittee has fully complied with all terms and conditions connected with such authorization.

7.10.4 Non-Applicability of Regulations of Concern

a. The emission limitations of 35 IAC 212.324 are not applicable to any emission unit subject to a specific emissions standard or limitation contained in 35 IAC Part 212 Subpart R, pursuant to 35 IAC 212.324 (a)(3).

b. Affected Boilers #11 and #12 are not subject to 35 IAC 217.141 because the heat input capacity of each of these boilers is below the applicability threshold of this rule (250 mmBtu/hr).

c. Power Boiler #1

i. Affected power boiler #1 is not subject to the NSPS for Electric Utility Steam Generating Units (40 CFR 60, Subpart Da) because it is not an electric utility steam generating unit as the term is defined in 40 CFR 60.41Da.

ii. Affected power boiler #1 is not subject to 40 CFR 60, Subpart D because it is subject to the NSPS in 40 CFR 60 Subpart Db as it meets the applicability requirements under 40 CFR 60.40b(a) [40 CFR 60.40b(j)].

iii. Affected Power Boiler #1 is not subject to the SO_2 standards of 40 CFR 60, Subpart Db because it meets the exemption provided at 40 CFR 60.42b(k)(2) [See also Condition 7.10.5(b)].

iv. Affected Power Boiler #1 is not subject to the NO_x standards of 40 CFR 60, Subpart Db pursuant to 40 CFR 60.44b(c), because it has an annual capacity factor for natural gas of 10 percent or less and is subject to a federally enforceable requirement that limits operation to an annual capacity factor of 10 percent or less for natural gas [See Condition 7.10.6(a)(iii)].

v. Affected Power Boiler #1 is not subject to particulate matter standards under 40 CFR 60, Subpart Db because it does not fire solid or liquid fuels.

d. Affected Power Boiler #1 is not subject to 35 IAC 217.121 because it is not "fossil fuel-fired" as defined by 35 IAC 211.2425, i.e., a unit for which fossil fuels provide more than 50 percent of the annual heat input to the unit.

e. Pursuant to 40 CFR 63.7491(k), Power Boiler #1 is not subject to 40 CFR Part 63 Subpart DDDDD because this boiler is a blast furnace gas fuel-fired boiler as defined in 40 CFR 63.7575.

f. Cooling Tower:

i. The affected cooling tower is not subject to 35 IAC 219.986(d), because the cooling tower does not cool process water.

ii. The affected cooling tower is not subject to 40 CFR Part 63 Subpart Q because no chromium-based water treatment chemicals are used.

7.10.5 Control Requirements

a. Requirements for affected Power Boiler #1 from Permit 06070023

i. Emissions of PM and PM_{10} from the affected Power Boiler #1 shall be controlled by the existing BFG pretreatment system, which entails treatment by dust catchers and wet scrubbers [T1].

ii. BFG and natural gas shall be the only fuels fired in the affected Power Boiler #1 [T1].

iii. Affected Power Boiler #1 shall be operated for the primary purpose of supplying steam and electricity to the source with no more than 219,000 MW-hour of excess electricity sent to any utility power distribution system for sale in any calendar year from the electrical generator associated with the unit [T1].

b. Pursuant to 40 CFR 60.42b(k)(2), the sulfur content of the fuel fired in Power Boiler #1 shall not exceed 0.16 lb/mmBtu.

c. Requirements for affected Boilers #11 and #12

Only natural gas, coke oven gas and blast furnace gases are allowed to use as the fuels.

d. Requirements for affected Cooling Tower

Pursuant to 40 CFR 63.402, the Permittee shall not use chromium-based water treatment chemicals in the water cooling tower.

7.10.5-1 Work Practice Requirements

a. Pursuant to Sections 39.5(7)(a) and (d) of the Act, unless the Permittee conducts continuous emission monitoring for CO for an affected boiler, the Permittee shall conduct an annual tune-up for the boiler, as follows, to maintain compliance with 35 IAC 216.121. If annual tune-ups or combustion adjustments are required for an affected boiler pursuant to 40 CFR 63, Subpart DDDDD, these tune-ups shall also be conducted in accordance of applicable provisions of this NESHAP.

i. Each annual tune-up must be no more than 13 months after the previous tune-up. If the boiler is not operating on the required date for a tune-up, the tune-up must be conducted within one week of startup.

ii. Each tune-up shall consist of the following:

A. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the burner inspection may be delayed until the next scheduled unit shutdown, but each burner must be inspected at least once every 36 months);

B. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

C. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly; and

D. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available.

iii. Measure the concentrations in the effluent stream of CO in parts per million by volume (ppmv), and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made); and

iv. Submit a report to the Illinois EPA within 30 days of each tune-up that contains the following information:

A. The identity of the boiler, the date of the tune-up and the individual(s) who performed the tune-up and a summary of their experience with combustion tune-ups of boilers.

B. The concentrations of CO in the effluent stream in ppmv and oxygen in volume percent, measured before and after the adjustments of the boiler;

C. A description of any corrective actions taken as a part of the combustion adjustment; and

D. The type and amount of fuel used over the 12 months prior to the annual adjustment.

b. Pursuant to 40 CFR 63.7530(h), for an affected boiler that is subject to emission limits in 40 CFR 63 Subpart DDDDD, the Permittee must minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, the Permittee must follow recommended procedures for a boiler of similar design for which manufacturer's recommended procedures are available.

7.10.6 Operational, Production and Emission Limitations

a. Limitations for affected Power Boiler #1 from Permit 06070023:

Note: Permit 06070023 includes certain limitations that apply to the combination of affected power boiler #1 and BFG flare #2, which is a new flare that was also constructed with the boiler. BFG flare #2 is generally addressed in Section 7.4 of this CAAPP permit.

i. The maximum design firing rate of affected Power Boiler #1 shall not exceed 505 mmBtu/hour [T1].

ii. The maximum design BFG input of affected Power Boiler #1 shall not exceed 476 mmBtu/hour [T1].

iii. Fuel usage for affected Power Boiler #1 and BFG flare #2 (see Section 7.4) shall not exceed the following limits (rolling 12-month basis) [T1]:

A. Natural gas: 341,666 mmBtu/year.

B. BFG and natural gas fuel usage combined: 4,511,426 mmBtu/year.

iv. Emissions of PM from affective Power Boiler #1, as measured by USEPA Method 5, shall not exceed 0.03 lb/mmBtu of exhaust [T1].

v. A. Emissions from affective Power Boiler #1 shall not exceed the following limits [T1]:

Pollutant	Mode	
	BFG* (Lbs/mmBtu)	Natural Gas (Lbs/mmBtu)
NO_x	0.05	0.12
CO	0.15	0.0824
VOM	---	0.0054
PM/PM_{10}	0.101	0.0075
SO_2	0.20	0.0006
Indiv. Metal HAP	0.00066	0.00066
Total HAPs	0.0053	0.0053

* BFG mode entails firing a mix of BFG with up to 10 percent natural gas.

B. Compliance with these limits shall be determined as a 3-hour average unless continuous emissions monitoring is conducted, in which compliance shall be determined as a daily average (24 operating hours).

C. Combined emissions from affected Power Boiler #1 and BFG flare #2 (see Section 7.4) shall not exceed the following limits [T1]:

Pollutant	Emissions	
	Tons/Month	Tons/Year
NO_x	12.5	124.74
CO	33.9	338.36
VOM	0.1	0.92
PM/PM_{10}	22.9	228.39
SO_2	45.2	451.14
Indiv. Metal HAP	0.2	1.5
Total HAPs	1.2	12.0

D. Compliance with annual limits in Condition 7.10.6(a) shall be determined on a monthly basis from the sum of the data for the current month plus the preceding 11 months (running 12

month total), unless otherwise specified in a particular condition.

b. Limits for the affected Cooling Tower from Permit 06070023 [T1]:

i. The total dissolved solids content of water circulating in the affected cooling tower shall not exceed 4,190 ppm on a monthly basis.

ii. Emissions of PM/PM_{10} from the affected cooling tower shall not exceed 0.39 tons/month and 3.86 tons/year. Compliance with the annual limit shall be determined from a running total of 12 months of data.

7.10.7-1 Current Testing Requirements

The Permittee shall conduct emission testing for the affected boilers as provided below pursuant to Sections 39.5(7)(c),(d) and (p) of the Act.

a. Requirements for affected Boilers #11 and #12:

i. PM and CO emissions shall be measured to determine compliance with 35 IAC 212.458(b)(9) (Condition 7.10.3(c)) and 35 IAC 216.121 (Condition 7.10.3(f)) in accordance with procedures in USEPA Methods 1 through 4 and Method 5 (or Method 201A), as provided in 35 IAC 212.108, and Method 10 or 10B.

ii. The testing shall be completed within 30 months of the effective date of this permit condition and may be done on either affected Boiler #11 or #12, as selected by the Illinois EPA.

iii. In addition to other required information, the test report shall include data for the sulfur and PM content of BFG and COG during the period of testing, with supporting data.

b. Requirements for affected Power Boiler #1:

i. Permittee shall conduct emission tests at least every five years on the affected Power Boiler #1.

ii. CO, NO_x, SO_2, PM_{10}, PM and VOM emissions shall be determined in accordance with the test methods identified below.

iii. These tests shall also include measurements of emissions of metals if the Permittee elects to conduct emissions testing to verify compliance with the limits for metal HAPs, as an alternative to applying data for the metal HAP content of material collected during pretreatment of the BFG.

iv. The following USEPA test methods shall be used for testing of emissions, unless another USEPA method is approved by the Illinois EPA.

Location of Sample Points	Method 1
Gas Flow and Velocity	Method 2
Flue Gas Weight	Method 3
Moisture	Method 4
SO_2	Method 6
PM/PM_{10} (filterable	Methods 201 or 201A*
PM (condensable)	Method 202
VOM	Method 18 or 25A
NO_x	Method 7E or 19
CO	Method 10 or 10B
Metals	Method 29

* The Permittee may also use Method 5 as an alternative to Method 201A, provided that the measured results shall be considered PM_{10}.

v. In addition to other required information, the test report shall include data for the sulfur and PM content of BFG and the metals content of the material removed from raw BFG by the pretreatment system during the period of testing, with supporting calculations.

c. For this emission testing, test notifications and reporting shall be done by the Permittee in accordance with Conditions 8.6.2 and 8.6.3 of this permit.

d. Observation of opacity shall be conducted during all emission tests of affected boilers in accordance with Method 9 and the results of these observations included in the reports for emission testing.

7.10.7-2 Additional Performance Testing Requirements (40 CFR Part 63, Subpart DDDDD)

a. Pursuant to 40 CFR 63.7505(c) and 63.7510, if affected Boiler #11 or #12 is subject to emission limits in 40 CFR 63 Subpart DDDDD, the Permittee must demonstrate compliance with all limits that are applicable using performance testing according to 40 CFR 63.7(a)(2) and 63.7520 and fuel analysis according to 40 CFR 63.7521, including a continuous emissions monitoring system (CEMS) where applicable, in a timely manner. The Permittee may demonstrate compliance with the applicable emission limit for hydrogen chloride or mercury using fuel analysis if the emission rate calculated according to 40 CFR 63.7530(c) is less than the applicable emission limit. Otherwise, the Permittee must demonstrate compliance for hydrogen chloride or mercury using performance testing.

i. Pursuant to 40 CFR 63.7545(d),the Permittee must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin.

ii. Pursuant to 40 CFR 63.7510(a), performance tests shall be conducted according to 40 CFR 63.7520(a), (c), (d) and (e) and Table 5 to 40 CFR 63, Subpart DDDDD fuel analysis for each type of fuel burned in the boiler shall be conducted according to 40 CFR 63.7521(a),(b) and (e) and Table 6 to 40 CFR 63, Subpart DDDDD, and performance evaluations for the oxygen monitor shall be conducted according to 40 CFR 63.7525.

b. Pursuant to 40 CFR 63.7530(g), if the Permittee elects to demonstrate that the gaseous fuel fired in affected Boiler #11 or #12 meets the specifications of an "other gas 1 fuel" as defined in 40 CFR 63.7575, an initial fuel specification analyses according to 40 CFR 63.7521(f) through (i) must be conducted.

i. If the mercury and hydrogen sulfide constituents in the gaseous fuels will never exceed the specifications included in the definition, the Permittee shall include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specifications outlined in the definition of other gas 1 fuels.

ii. Pursuant to 40 CFR 63.7540(c), if the Permittee elects to demonstrate that the unit meets the specifications for hydrogen sulfide and mercury for the other gas 1 subcategory and cannot submit a signed certification under 40 CFR 63.7545(g) because the constituents could exceed or vary above the specifications, the Permittee must conduct monthly fuel specification testing of the gaseous fuels, according to the procedures in 40 CFR 63.7521(f) through (i) and 40 CFR 63.7540(c) and maintain records of the results of the testing as outlined in 40 CFR 63.7555(g).

7.10.8-1 Current Monitoring Requirements

Pursuant to 39.5(7)(a) and (d) of the Act, all affected boilers and the cooling tower are subject to the following monitoring requirements:

a. Opacity Observations

The Permittee shall conduct opacity observations for each affected boiler semi-annually in accordance with 40 CFR Part 60, Appendix A, Method 9. The duration of these

observations shall be a minimum of 30 minutes for each boiler.

b. Cooling Tower

i. The Permittee shall sample and analyze the water being circulated in the affected cooling tower on at least a monthly basis for the total dissolved solids content.

ii. Upon written request by the Illinois EPA, the Permittee shall have the water circulating in the affected cooling tower sampled and analyzed for the presence of hexavalent chromium in accordance with the procedures of 40 CFR 63.404(a) and (b).

c. Analysis of BFG

i. The Permittee shall sample and analyze cleaned BFG after the pretreatment system for sulfur content (lb/scf and lb/mmBtu), using appropriate ASTM methods or other comparable methodology. These measurements shall be conducted on at least a quarterly basis. The records for this activity shall also include operating data for the blast furnaces and the BFG pretreatment system at the time of sampling.

ii. The Permittee shall sample and analyze the cleaned BFG after the pretreatment system for PM content (gr/scf and lbs/mmBtu) and the material collected by the BFG pretreatment system for HAP metal content (by weight, dry basis, for individual metals as addressed by Method 29) using appropriate ASTM methods or other comparable methodology. These measurements shall be conducted at least every two years. The records for this activity shall also include operating data for the blast furnaces and the BFG pretreatment system at the time of sampling.

7.10.8-2 Additional Monitoring Requirements (40 CFR Part 63 Subpart DDDDD)

Unless an affected boiler is operating as a blast furnace gas fuel-fired boiler, as defined in 40 CFR 63.7575, or is otherwise exempt, beginning on the compliance date of this NESHAP for existing sources, the Permittee must:

a. Install, operate, and maintain a continuous oxygen monitor according to the procedures in 40 CFR 63.7525 (a)(1) through (6) and 63.7535. The oxygen level shall be monitored at the outlet of the boilers [40 CFR 63.7525(a)].

b. Monitor the operating parameters identified in Items 7, 8 and 9 of Table 8 of 40 CFR 63 Subpart DDDDD [40 CFR 63.7540(a)].

c. Operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of 40 CFR 63 Subpart DDDDD except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests [40 CFR 63.7540(a)(1)].

7.10.9 Recordkeeping Requirements

The Permittee shall maintain records of the following items, pursuant to Sections 39.5(7)(a) and (e) of the Act:

a. Affected Power Boiler #1:

i. A file which contains supporting documentation which demonstrates the maximum design firing rate of the affected boiler (mmBtu/hour), the maximum design BFG input, and the manufacturer's guarantees for the emission rates of the natural gas burners in the affected boiler.

ii. NSPS Data

A. The applicable recordkeeping required by the NSPS for startup, shutdown and malfunction, pursuant to 40 CFR 60.7(b).

B. Daily records of the fuel consumption, pursuant to 40 CFR 60.49b(d)(1).

iii. Fuel usage

A. Records for the amounts of fuel burned by type (mmBtu/month and mmBtu/year) for the affected boiler.

B. Records for the amounts of fuel burned for the affected boiler and the new BFG flare, combined, by type (mmBtu/month and mmBtu/year).

iv. Emissions

The Permittee shall keep the following records related to the emissions of affected Power Boiler #1 to verify compliance with the applicable limits in Condition 7.10.6(a):

A. A file containing the emission factors used by the Permittee to determine emissions of pollutants other than SO2 from the affected boiler and BFG Flare #2, with supporting documentation. These records shall be reviewed

and updated by the Permittee as necessary to assure that the emission factors that it uses to determine emissions of the affected boiler do not understate actual emissions. These records shall be prepared and copies sent to the Illinois EPA in accordance with Condition 5.9.6(c).

B. Records of emissions of NO_x, CO, VOM, PM/PM_{10}, SO_2 and HAPs (tons/month and tons/year) from this boiler, with supporting calculations.

C. Records of summation of emissions of NO_x, CO, VOM, PM/PM_{10}, SO_2 and HAPs from this boiler and BFG Flare #2 (tons/month and tons/year), with supporting calculations.

v. Records of the electricity from the generator associated with Power Boiler #1 sent to the grid for sale per calendar year (MW-hours).

b. Affected Cooling Tower:

i. The Permittee shall keep records of the water circulation capacity of the cooling tower (gallons/minute, hourly average), with supporting calculations.

ii. The Permittee shall keep records of emissions of PM/PM_{10} (tons/month and tons/year), with supporting calculations.

c. Affected Boilers #11 and #12:

i. The following operating information for each boiler:

Usage of each type of fuel (natural gas, COG and BFG gas), in million ft^3 per month and million ft^3 per year.

ii. The Permittee shall keep inspection, maintenance, and repair logs with dates and the nature of such activities for each boiler.

iii. A file containing the emission factors used by the Permittee to determine emissions of NO_x and CO from affected Boilers #11 and #12, with supporting documentation. These records shall be reviewed and updated by the Permittee as necessary to assure that the emission factors that it uses to determine NO_x and CO emissions of these boilers do not understate actual emissions.

d. Records for Startups of Affected Boilers, pursuant to Section 39.5(7)(b) of the Act

i. The Permittee shall maintain startup procedures for each affected boiler, as required by Condition 7.10.3(i)(ii).

ii. The Permittee shall maintain the following records for each startup of an affected boiler:

A. Date, time and duration of the startup.

B. A description of the startup and reason(s) for the startup.

C. Whether a violation of an applicable standard may have occurred during startup accompanied by the information in Condition 7.10.9(d)(iv) if a violation may have or did occur.

D. Whether the established startup procedures, maintained above, were followed accompanied by the information in Condition 7.10.9(d)(iii) if there were departure(s) from those procedures.

iii. If the established startup procedures were not followed during a startup, the Permittee shall maintain the following records:

A. A description of the departure(s) from the established procedures.

B. The reason(s) for the departure(s) from the established procedures.

C. An explanation of the consequences of the departure(s) for emissions, such as whether the departure(s) prolonged the startup or resulted in additional emissions, and if so:

1. The actions taken to minimize emissions and the duration of the startup; and

2. An explanation whether similar incidents might be prevented in the future and if so, the corrective actions taken or to be taken to prevent similar incidents.

iv. If a violation did or may have occurred during a startup, the Permittee shall maintain the following records:

A. Identification of the applicable standard(s) that were or may have been violated.

B. An explanation of the nature of such violation(s), including the magnitude of such excess emissions.

C. A description of the actions taken or to be taken to minimize the magnitude of emissions and duration of the startup.

D. An explanation whether similar incidents could be prevented or ameliorated in the future and if so, a description of the actions taken or to be taken to prevent similar incidents in the future.

e. Records for Malfunctions or Breakdowns

Pursuant to 35 IAC 201.263, the Permittee shall maintain records of continued operation of the affected boilers as addressed by Condition 7.10.3(j), during malfunctions or breakdowns, which at a minimum, shall include the following records. The preparation of these records shall be completed within 45 days of an incident, unless the Permittee conducts a root cause analysis for the incident, in which case the preparation of these records, other than the root cause analysis, shall be completed within 120 days of the incident.

i. Date, time and duration of the incident.

ii. A detailed description of the incident, including:

A. A chronology of significant events during and leading up to the incident.

B. Relevant operating data for the unit, including information such as operator log entries and directives provided by management during the incident.

C. The measures taken to reduce the quantity of emissions and the duration of the incident including the resources utilized to address the incident.

D. The magnitude of emissions during the incident.

iii. An explanation why continued operation of an affected boiler was necessary to prevent personnel injury or prevent equipment damage.

iv. A discussion of the cause(s) or probable cause(s) of the incident including the following:

A. Whether the incident was sudden, unavoidable, or preventable, including:

1. Why the equipment design did not prevent the incident;

2. Why better maintenance could not have avoided the incident;

3. Why better operating practices could not have avoided the incident; and

4. Why there was no advance indication for the incident.

B. Whether the incident stemmed from any activity or event that could have been foreseen, avoided or planned for.

C. Whether the incident was or is part of a recurring pattern indicative of inadequate design, operation or maintenance.

v. A description of any steps taken or to be taken to prevent similar future incidents or reduce their frequency and severity.

vi. As an alternative to keeping the records required by Condition 7.10.9(e)(iv), the Permittee may perform a root cause analysis. For this purpose, a root cause analysis is an analysis whose purpose is to determine, correct and eliminate the primary causes of the incident and the excess emissions resulting there from. If the Permittee performs a root cause analysis method that would define the problem, define all causal relationships, provide a causal path to the root cause, delineate the evidence, and provide solutions to prevent a recurrence. Such an analysis shall be completed within one year of the incident.

f. Records for the emission testing conducted on the affected boilers.

g. If the Permittee operates under manufacturer's specifications or manufacturer's instructions, such manufacturer's documentation shall be kept at the source as part of the required records.

h. Unless an affected boiler is operating as a blast furnace gas fuel-fired boiler, as defined in 40 CFR 63.7575, or is otherwise exempt, beginning on the compliance date of this NESHAP for existing sources, the Permittee must keep records in accordance with 40 CFR 63.7555(a) through (h) as applicable.

7.10.10 Reporting Requirements

a. i. The Permittee shall promptly notify the Illinois EPA, Air Compliance Section, within 30 days of deviations of the affected boilers and affected cooling tower from the following applicable requirements unless a NESHAP standard specifies a different time frame, pursuant to Section 39.5(7)(f)(ii) of the Act:

A. Requirements in Condition 7.10.3(b), (d) and (e) through (h).

B. Requirements in Condition 7.10.5.

C. Requirements in Condition 7.10.6.

ii. All such deviations shall be summarized and reported as part of the semiannual monitoring report required by Condition 8.6.1.

b. The Permittee shall notify the Illinois EPA, Air Compliance Section, of all other deviations as part of the semiannual monitoring reports required by Condition 8.6.1.

c. All deviation reports described in Condition 7.10.10(a) and (b) above shall contain the following:

i. Date, time and duration of the deviation;

ii. Description of the deviation;

iii. Probable cause of the deviation; and

iv. Any corrective actions or preventive measures taken.

d. Reporting on the State malfunction and breakdown authorization shall be performed in accordance with Condition 5.10.5-2.

e. For affected Power Boiler #1, the Permittee shall comply with the applicable reporting requirements of the NSPS, as specified in 40 CFR 60.7 and 60.49b.

f. Unless an affected boiler is operating as a blast furnace gas fuel-fired boiler, as defined in 40 CFR 63.7575, or is otherwise exempt, beginning on the compliance date of this NESHAP for existing sources, the Permittee must report each instance in which it did not meet each emission limit and operating limit in Tables 1 through 4 to 40 CFR 63 Subpart DDDDD that are applicable. These instances are deviations from the established emission limits. These deviations must be reported according to the requirements in 40 CFR 63.7550.

g. Reporting on the State startup authorization shall be performed in accordance with Condition 5.10.5-1.

h. Reporting on the Federal SSM authorization shall be performed in accordance with Condition 5.10.5-3.

7.10.11 Compliance Procedures

For affected boilers, compliance with the applicable standards of Condition 7.10.3, the work practice requirements of Condition 7.10.5-1, and the production/operating and the emission limits of Condition 7.10.6 is addressed by the work practices, testing, monitoring, recordkeeping and reporting requirements in Section 7.10 of this permit.

7.10.12 State-Only Conditions

a. Applicable requirements for affected Boilers #11 and #12 from Permit 10080022:

i. Pursuant to 35 IAC 217.150, 217.152, and 217.160, by the applicable compliance date for 35 IAC Part 217 Subparts D and E, the Permittee shall comply with applicable requirements of these rules for the affected boilers, including:

A. Compliance with the applicable NO_x emissions limitation in lb/mmBtu, calculated in accordance with 35 IAC 217.164(b), on an ozone season (May 1 through September 30) and annual basis [35 IAC 217.164(b)].

B. Operation of each affected boiler in a manner consistent with good air pollution control practices to minimize NO_x emissions [35 IAC 217.150(e)].

C. Certifying to the Illinois EPA that the affected boilers will be in compliance with the applicable emissions limitation of 35 IAC 217.164 by the applicable compliance date [35 IAC 217.152 and 217.155(b)].

D. Installation, operation and maintenance of a Continuous Emissions Monitoring System (CEMS) on each affected boiler to measure emissions of NO_x, with accompanying recordkeeping and reporting for the operation and maintenance of each CEMS [35 IAC 217.157(a)(2) and 217.156(b)(9), (b)(10) and (j)].

ii. Recordkeeping Requirements [39.5(7)(e) of the Act]

Beginning on the compliance date of 35 IAC 217 Subparts D and E, the Permittee shall keep the following records for each Boiler #11 and #12:

A. Usage of each type of fuel (natural gas, coke oven gas and blast furnace gas), in million ft^3 per month and million ft^3 per year.

B. The actual heat input in mmBtu per ozone season and mmBtu per year, for each fuel, with supporting documentation for the heat content of each fuel.

C. The applicable NO_x emission limitation in lb/mmBtu for each ozone season and each calendar year, calculated in accordance with 35 IAC 217.164(b).

D. The average hourly NO_x emission data.

E. The ozone season and annual NO_x emissions (pounds).

F. The ozone season average and annual average NO_x emission rates (lbs/mmBtu heat input) calculated within 30 days of the end of the averaging periods (i.e. calculated by October 30 for ozone season averaging period and by January 30 for annual averaging period).

G. Inspection, maintenance, and repair logs with dates and the nature of such activities for each affected boiler.

iii. Reporting Requirements [39.5(7)(f) of the Act]

If there is any deviation of the requirements of Condition 7.10.12, the Permittee shall promptly report to the Illinois EPA as specified below and report shall include a description of the deviation, the probable cause of the deviation, corrective actions taken, and any preventive measures taken:

A. Deviations from the NO_x emission limitation in 35 IAC 217.164(b) shall be reported within 30 days of such occurrence.

B. Other deviations shall be reported in a semi-annual report.

7.10.13 Construction Permit Conditions for Equipment that is not yet built

Applicable requirements for portable Boilers #1 through #4 from Permit 10100042:

a. Pursuant to the NSPS, 40 CFR 60.11(d), at all times the Permittee shall, to the extent practicable, maintain and operate each portable boiler in a manner consistent with good air pollution control practices for minimizing emissions.

b. Pursuant to 35 IAC 216.121, the emission of carbon monoxide (CO) from each portable boiler shall not exceed 200 ppm, corrected to 50 percent excess air.

c. Pursuant to 35 IAC 212.123(a), the opacity of the exhaust from each portable boiler shall not exceed 30 percent, except as provided in 35 IAC 212.123(b).

d. This permit is issued based on the emissions of HAPs as listed in Section 112(b) of the Clean Air Act from the affected boilers being less than 10 tons per year of a single HAP and 25 tons per year of any combinations of such HAPs, so that these boilers are considered a minor source for HAPs.

e. This permit is issued based on the portable boilers not being subject to the control requirements of 35 IAC 217, Subparts D and E, which establish requirements that reflect Reasonably Available Control Technology (RACT) for boilers related to emission of nitrogen oxide (NO_x). This is because the NO_x emissions from each portable boiler are restricted to less than 15 tons per year and to less than 5 tons per ozone season, pursuant to 35 IAC 217.150(a), as addressed further.

f. Natural gas shall be the only fuel fired in the portable boilers.

g. The maximum design heat input capacity of each portable boiler, as defined by the NSPS, 40 CFR 60.41c, shall not exceed 100 mmBtu/hour.

   Note: If a portable boiler were to have a heat input capacity of greater than 100 mmBtu/hr, it would be subject to the NSPS, 40 CFR 60 Subpart Db, rather than Subpart Dc.

h. i. The total consumption of natural gas by the portable boilers shall not exceed 1,738 million scf per year, combined.

   ii. Beginning Calendar year 2012 or such later date, the natural gas usage by each portable boiler shall not exceed 812 million scf per year and 267 million scf

during each ozone season (May 1 through September 30).

i. The portable boilers shall only be used to address interruptions in the normal steam supply to the Granite City Works. For this purpose, the portable boilers and existing boilers may operate simultaneously, as may be needed to ensure availability of the portable boilers and facilitate transitions between existing boilers and the portable boilers.

j. i. Short-term emissions from each portable boiler shall not exceed 0.036 lb of NO_x/mmBtu and 3.6 and 3.8 lbs/hour, for NO_x and CO, respectively.

ii. Annual emissions from the portable boilers, combined shall not exceed the following limits. These limits are established based on total fuel usage of 1,738 million scf per year. Compliance with these limitations and the annual fuel consumption limit shall be determined from a running total of 12 months of data.

Pollutant	Emission Limit (ton/year)
NO_x	31.9
CO	33.2
VOM	3.5
$PM/PM_{10}/PM_{2.5}$	1.1
SO_2	1.3
Individual HAP[1]	1.8
Total HAP	3.5

[1] Individual HAP refers to individual pollutants, such as Formaldehyde, Benzene, Toluene, Hexane, etc.

k. Beginning Calendar Year 2012, the NO_x emissions of each portable boiler shall be less than the applicability thresholds of 35 IAC 217, Subparts D and E, i.e., less than 15 tons per year and less than 5 tons during each ozone season.

l. The Permittee shall operate and maintain the portable boilers in accordance with good air pollution control practices to assure proper functioning of equipment and minimize malfunctions, including maintaining the boiler in accordance with written procedures developed for this purpose.

m. Within 90 days after a written request from the Illinois EPA or such later date agreed to by the Illinois EPA, the Permittee shall have NO_x and CO emissions of portable

boiler(s), as specified in the request, measured by an independent testing service approved by the Illinois EPA.

n. The Permittee shall maintain the following records for the portable boilers:

i. A file containing the following information:

A. The maximum design heat input capacity of each portable boiler, mmBtu/hour, with supporting documentation.

B. The maximum fuel flow rate to each portable boiler, in scf/hour and mmBtu/hour, with supporting documentation.

C. The guarantee or other information for the NO_x and CO emission rates of each portable boiler, in lb/hour and in lb/mmBtu (NO_x only), with supporting documentation.

ii. An operating log or other records for the portable boilers that, at a minimum, shall include the following information:

A. Information identifying each period when portable boiler(s) are operated, with the explanation why the boiler(s) need to be operated to maintain the normal steam supply for the source.

B. If the maximum design heat input capacity of the portable boiler is more than 95 mmBtu/hour, operating records to demonstrate that the boiler is not fired at more than 100 mmBtu/hour.

C. Information for each startup and shutdown, including date, time and duration, as required by 40 CFR 60.7(b).

D. Information for any incident in which the operation of each portable boiler continued during malfunction or breakdown, as required by 40 CFR 60.7(b). These records shall include date, time, and duration; a description of the incident; whether emissions exceeded or may have exceeded any applicable standard; a description of the corrective actions taken to reduce emissions and the duration of the incident; and a description of the preventative actions taken.

iii. An inspection, maintenance, and repair log with dates and the nature of such activities for the portable boilers.

iv. The following records for the natural gas usage of the portable boilers:

A. Natural gas usage of each boiler, pursuant to 40 CFR 60.48c(g) (scf/month).

B. Total natural gas usage of the boilers (scf/year).

v. Records of the monthly and annual emissions of NO_x, CO, $PM/PM_{10}/PM_{2.5}$, VOM, SO_2, and HAPs from the boilers (tons/month and tons/year), with supporting data and calculations.

vi. Beginning Calendar year 2012, records of NO_x emissions for each portable boiler for the calendar year (ton/year) and for the ozone season (ton/season).

o. Pursuant to 40 CFR 60.7(a)(3) and 60.48c(a), the Permittee shall furnish the Illinois EPA with written notification of initial startup of each portable boiler. This notification shall be submitted within 15 days after the initial startup of the portable boiler, postmarked by such date, and include the following information. For this purpose, a separate notification shall be provided each time that portable boiler(s) are installed at the Granite City Works.

i. The design heat input capacity of the boiler and identification of the fuels to be combusted in the boiler, pursuant to 40 CFR 60.48c(a)(1).

ii. The annual capacity factor at which the Permittee anticipates operating the boiler based on fuel fired, pursuant to 40 CFR 60.48c(a)(3).

iii. With the notification required from above, the Permittee shall also provide the manufacturer and serial number of portable boiler(s).

p. The Permittee shall notify the Illinois EPA of deviations of the portable boilers with the requirements of Condition 7.10.13 within 30 days of an occurrence. Reports shall describe the deviation, the probable cause of such deviations, the corrective actions taken, and any preventive measures taken.

7.11 Internal Combustion Engine

7.11.1 Description

A diesel fuel fired emergency engine-generator is used for power outages at the facility.

Note: This narrative description is for informational purposes only and is not enforceable.

7.11.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Date Constructed	Emission Control Equipment
Engine	Emergency Engine-Generator (maximum power output 3,500 HP)	2001	None

7.11.3 Applicable Provisions and Regulations

a. The "affected engine" for the purpose of these unit-specific conditions, is the emission unit described in Conditions 7.11.1 and 7.11.2.

b. The affected engine is subject to 35 IAC 212.458(b)(7) and (c), which provides that its PM_{10} emissions shall not exceed 22.9 mg/scm (0.01 gr/scf), provided however that this limit shall not apply if there are no visible emissions, except if a stack test is performed. The absence of visible emissions is not a defense to a finding violation.

c. The affected engine is subject to 35 IAC 212.123(a), which provides that no person shall cause or allow the emission of smoke or other particulate matter, with an opacity greater than 30 percent, into the atmosphere from any emission unit other than those emission units subject to the requirements of 35 IAC 212.122, except as allowed by 35 IAC 212.123(b) and 212.124.

d. The affected engine is subject to 35 IAC 214.301 and 35 IAC 214.304/214.122, which provides that no person shall cause or allow the emission of sulfur dioxide into the atmosphere from any process emission source to exceed 2000 ppm and from any fuel burning process emission unit burning distillate oil to exceed 0.3 lbs/mmBtu.

7.11.4 Non-Applicability of Regulations of Concern

a. The affected engine is not subject to 40 CFR Part 63 Subpart ZZZZ because it is not a spark ignition engine.

b. The affected engine is not subject to 40 CFR Part 60 Subpart IIII, because the affected engine was manufactured before 2006 and was not modified or reconstructed

thereafter, so does not meet applicable criteria in 40 CFR 60.4200(a).

c. The affected engine is not subject to 35 IAC Part 217, because the affected engine is not a type of process emission unit addressed by Part 217.

d. The affected engine is not subject to the requirements of 35 IAC 212.321 because it does not have a process weight rate as defined in 35 IAC 211.5250.

e. The affected engine is not subject to 35 IAC 216.121, because the affected engine is not by definition a fuel combustion emission unit.

f. 35 IAC 212.324 is not applicable to the affected engine pursuant to 35 IAC 212.324(a)(3), because the affected engine is subject to 35 IAC 212.458(b)(7), an emission limitation in 35 IAC Part 212, Subpart R.

7.11.5 Control Requirements and Work Practices

The operation of the emergency generator is limited to 500 hours per year [00060003, T1].

7.11.6 Production and Emission Limitations from Permit 00060003 [T1]

a. Emissions of the affected engine shall not exceed the following limits:

Pollutant	Emissions (lbs/hr)	Emissions (T/yr)
PM	2.48*	0.62
CO	21.11*	5.3
NO_x	79.49*	19.9
SO_2	12.54	3.1

* Operation at a level of 10 percent higher than the applicable hourly emissions limits above is allowed during startup.

b. Compliance with annual limits shall be determined on a monthly basis from the sum of the data for the current month plus the preceding 11 months (running 12 month total) [T1].

7.11.7 Testing Requirements

Upon the written request from the Illinois EPA, the emission tests shall be conducted by the Permittee for the affected engine to verify compliance with emission limits in Condition 7.11.6 as follows [Sections 39.5(7)(c), (d) and (p) of the Act].

a. The following USEPA test methods shall be used, unless another USEPA method is approved by the Illinois EPA.

Location of Sample Points	Method 1
Gas Flow and Velocity	Method 2
Flue Gas Weight	Method 3
Moisture	Method 4
PM	Method 5
NO_x	Method 7E or 19
CO	Method 10 or 10B

b. Observations of opacity shall be conducted during these emission tests in accordance with Method 9 and the results of these observations included in the reports for emission testing.

c. For this emission testing, test notifications and reporting shall be done by the Permittee in accordance with Conditions 8.6.2 and 8.6.3 of this permit.

7.11.8 Monitoring Requirements

a. The Permittee shall perform annual sampling and analysis for sulfur content (lbs/mmBtu) in the fuel for the affected engine or obtain a certification for each fuel supplied delivery for the affected engine [Section 39.5(7)(d) of the Act].

b. The Permittee shall conduct opacity observations for the affected engine in accordance with Method 9 on an annual basis if the affected engine starts for purposes of reliability testing. The duration of Method 9 test shall be equal to 30 minutes or the duration of the reliability test, whichever is less [Section 39.5(7)(p) of the Act].

7.11.9 Recordkeeping Requirements

The Permittee shall maintain records of the following items for the affected engine, pursuant to Sections 39.5(7)(a) and (e) of the Act:

a. A file for the affected engine containing:

i. The manufacturer's emission guarantees or emission data for the engine, for PM, CO and NO_x, both during normal operation and startup (lbs/hour and lbs/gallon) and manufacturer's data for fuel consumption and exhaust flow rate from the engine, with supporting documentation.

ii. Engineering calculations to demonstrate that PM emissions comply with 35 IAC 212.458(b)(7) and to determine the greatest sulfur content (lbs/mmBtu) in fuel with which compliance with 35 IAC 214.301 and 35 IAC 214.304/214.122 would be shown.

iii. The emission rate(s) used by the Permittee to determine emissions of the affected engine when these rates are different from the manufacturer's rates, accompanied by supporting documentation. Copies of these records shall be submitted to the Illinois EPA, with initial records submitted within 15 days of the date that the records are prepared or 30 days after the effective date of this permit, whichever is later and subsequent revisions to these records submitted within 15 days of the date that the Permittee completes preparation of revised records.

b. Records of fuel consumption (gal/month and gal/year).

c. Records of hours of operation (hrs/yr).

d. Records for number of startups.

e. Records for the sulfur content (lbs/mmBtu) of fuel as determined by sampling and analyses of fuel or copies of supplier certifications for sulfur content of fuel and identification of any use of oil whose sulfur content exceeded the level for compliance, as determined pursuant to Condition 7.11.9(a)(ii).

f. Records of emissions of PM, CO, NO_x and SO_2 (tons/month and tons/year) from the engine with supporting calculations. For this purpose, PM, CO and NO_x emissions shall be calculated from fuel usage and number of startups and the manufacturer's emission guarantees for emission rates or such higher emission rate(s) that accurately reflect actual operation of the engine. SO_2 emissions shall be calculated from the sulfur content of the fuel and fuel usage, assuming complete conversion of sulfur to SO_2.

g. Records for stack tests and opacity observations.

7.11.10 Reporting Requirements

a. i. Pursuant to Section 39.5(7)(f)(ii) of the Act, the Permittee shall promptly notify the Illinois EPA, Air Compliance Section, within 30 days of deviations by the affected engine as follows:

A. Requirements in Condition 7.11.3(b), (c) and (d).

B. Requirements in Condition 7.11.5.

C. Requirements in Condition 7.11.6.

ii. All such deviations shall be summarized and reported as part of the semiannual monitoring report required by Condition 8.6.1.

b. The Permittee shall notify the Illinois EPA, Air Compliance Section, of all other deviations as part of the semiannual monitoring reports required by Condition 8.6.1.

c. All deviation reports described in Condition 7.11.10 above shall contain the following:

i. Date, time and duration of the deviation;

ii. Description of the deviation;

iii. Probable cause of the deviation; and

iv. Any corrective action or preventive measures taken.

7.11.11 Operational Flexibility/Anticipated Operating Scenarios

Operational flexibility is not set for the affected engine.

7.11.12 Compliance Procedures

For the affected engine, compliance with the applicable standards of Condition 7.11.3, the control/work practice requirements of Condition 7.11.5, and the production/emission limits of Condition 7.11.6 is addressed by testing, monitoring, recordkeeping and reporting requirements in Section 7.11 of this permit.

7.11.13 State-Only Conditions

State-only conditions are not being established.

7.12 Gasoline Storage and Dispensing

7.12.1 Description

Gasoline storage and dispensing is conducted for the Permittee's fleet of gasoline fueled vehicles. There are several such stations at the facility, so that fleet vehicles do not have to travel on public roads to reach the fueling stations.

Note: This narrative description is for informational purposes only and is not enforceable.

7.12.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Date Constructed	Emission Control Equipment
Gasoline Storage	Four storage tanks located at: Storeroom (1,000 gallons capacity); Machine Shop (1,000 gallons capacity); Wastewater Facility (250 gallons capacity); Blast Furnace Facility(1,000 gallons capacity)	N/A	Control Practices: Submerged loading pipe (all tanks) and Stage I system (tanks with 1,000 gallons capacity)

7.12.3 Applicable Provisions and Regulations

a. The "affected gasoline storage tanks", for the purpose of these unit-specific conditions are the tanks described in Conditions 7.12.1 and 7.12.2 above.

b. The affected gasoline storage tank at the wastewater facility is subject to the following:

No person shall cause or allow the loading of any organic material into any stationary tank having a storage capacity of greater than 946 l (250 gal), unless such tank is equipped with a permanent submerged loading pipe [35 IAC 219.122(b)].

c. Pursuant to 35 IAC 219.583(c)(1), the affected gasoline storage tanks at the storeroom, machine shop and blast furnace facility are subject to the following requirements of 35 IAC 219.583(a): No person shall cause or allow the transfer of gasoline from any delivery vessel into any stationary storage tank at a gasoline dispensing facility unless:

i. The tank is equipped with a submerged loading pipe [35 IAC 219.583(a)(1)].

ii. The vapors displaced from the storage tank during filling are processed by a vapor control system [35 IAC 219.583(a)(2)].

iii. All tank vent pipes are equipped with pressure/vacuum relief valves that are designed and shall be set to resist a pressure of at least 3.5 inches water column and to resist a vacuum of no less than 6.0 inches water column [35 IAC 219.583(a)(3)].

d. Pursuant to 35 IAC 219.585(a), all the affected gasoline storage tanks are subject to the following: No person shall sell, offer for sale, dispense, supply, offer for supply, or transport for use in Illinois gasoline whose Reid vapor pressure exceeds the applicable limitations set forth below during the regulatory control periods, which shall be June 1 to September 15.

i. The Reid vapor pressure of gasoline, a measure of its volatility, shall not exceed 7.2 psi (9.68 kPa) during the regulatory control period [35 IAC 219.585(b)].

ii. The Reid vapor pressure of ethanol blend gasolines having at least nine percent (9%) but not more than ten percent (10%) ethyl alcohol by volume of the blended mixture, shall not exceed the limitations for gasoline set forth in Condition 7.12.2(d)(i) above by more than 1.0 psi (6.9 kPa) [35 IAC 219.585(c)].

7.12.4 Non-Applicability of Regulations of Concern

a. This permit is issued based on the affected gasoline storage tank not being subject to the NSPS for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels), 40 CFR Part 60, Subpart Kb, because each tank is less than 40 cubic meters (10,566 gallons).

b. This permit is issued based on the affected gasoline storage tanks not being subject to 35 IAC 219.121, because each affected tank is less than 40,000 gallons [35 IAC 219.121].

c. This permit is issued based on the affected gasoline storage tanks not being subject to 35 IAC 219.122(a), because each affected tank is less than 40,000 gallons [35 IAC 219.122].

d. The affected gasoline storage tanks are not subject to 35 IAC 219.301 because the affected gasoline storage tanks do not use organic material. In addition, the storage tanks are regulated by 35 IAC 219.122(b) and 35 IAC 219.583(c)(1).

e. The affected gasoline storage and dispensing operations are not part of a bulk gasoline plant (35 IAC 219.581) or bulk gasoline terminals (35 IAC 219.582) pursuant to relevant definitions in 35 IAC Part 211.

f. This permit is issued based on the gasoline storage and dispensing operations performed at wastewater facility not being subject to 35 IAC 219.583(a)(2) and (a)(3) pursuant to 35 IAC 219.583(b)(3), because the tank capacity is less than 575 gallons.

g. The affected gasoline storage tanks are not eligible for the exemption from the permitting in 35 IAC 219.583(e) because they are not located at retail dispensing operations, as defined at 35 IAC 211.5630.

7.12.5 Control Requirements and Work Practices

The affected gasoline storage tanks (other than the affected gasoline storage tank at the wastewater facility) are subject to the following control requirements and work practices:

a. Pursuant to 35 IAC 219.583(c), each owner of a gasoline dispensing operation shall:

i. Install all control systems and make all process modifications required by Condition 7.12.3(c) (see also 35 IAC 219.583(a)) [35 IAC 219.583(c)(1)];

ii. Provide instructions to the operator of the gasoline dispensing operation describing necessary maintenance operations and procedures for prompt notification of the owner in case of any malfunction of a vapor control system [35 IAC 219.583(c)(2)]; and

iii. Repair, replace or modify any worn out or malfunctioning component or element of design [35 IAC 219.583(c)(3)].

b. Pursuant to 35 IAC 219.583(d), each operator of a gasoline dispensing operation shall:

i. Maintain and operate each vapor control system in accordance with the owner's instructions [35 IAC 219.583(d)(1)];

ii. Promptly notify the owner of any scheduled maintenance or malfunction requiring replacement or repair of a major component of a vapor control system [35 IAC 219.583(d)(2)];

iii. Maintain gauges, meters or other specified testing devices in proper working order [35 IAC 219.583(d)(3)]; and

iv. Pursuant to 35 IAC 219.583(d)(4), operate the vapor collection system and delivery vessel unloading points in a manner that prevents:

A. A reading equal to or greater than 100 percent of the lower explosive limit (LEL measured as propane) when tested in accordance with the procedure described in EPA 450/2-78-051 Appendix B [35 IAC 219.583(d)(4)(A)]; and

B. Avoidable leaks of liquid during the filling of storage tanks [35 IAC 214.583(d)(4)(B)].

v. Within 15 business days after discovery of the leak by the owner, operator, or the Agency, repair and retest a vapor collection system which exceeds the limits of Condition 7.12.5(iv) above [35 IAC 219.583(d)(5)].

c. Pursuant to 35 IAC 219.584(a), the Permittee shall ensure that each gasoline delivery vessel that comes on to the property to fill the affected gasoline storage tanks at the storeroom, machine shop, or blast furnace facility are complying with the following:

i. Shall have a vapor space connection that is equipped with fittings which are vapor tight;

ii. Shall have its hatches closed at all times during unloading operations, unless a top loading vapor recovery system is used;

iii. Shall not internally exceed a gauge pressure of 18 inches of water or a vacuum of 6 inches of water;

iv. Shall be designed and maintained to be vapor tight at all times during normal operations;

v. Shall not be refilled in Illinois at other than a bulk gasoline terminal that complies with the requirements of 35 IAC 219.582 or a bulk gasoline plant that complies with the requirements of 35 IAC 219.581(b).

vi. Shall have a sticker affixed to the tank adjacent to the tank manufacturer's data plate which contains the tester's name, the tank identification number and the date of the test. The sticker shall be in a form prescribed by the Illinois EPA.

7.12.6 Production and Emission Limitations

Production and emission limitations are not set for the affected gasoline storage tanks.

7.12.7 Testing Requirements

a. Pursuant to 35 219.583(a)(4), the Permittee shall demonstrate compliance with the pressure/vacuum relief valves specifications of Condition 7.12.3(c)(iii) at a gasoline dispensing operation by measuring and recording the pressure indicated by a pressure/vacuum gauge at each tank vent pipe 30 days after installation of each pressure/vacuum relief valve, and at least annually thereafter. The test shall be performed on each tank vent pipe within two hours after product delivery into the respective storage tank. For manifold tank vent systems, observations at any point within the system shall be adequate.

b. The Permittee shall test the relief valves whenever there is a modification of an existing vapor control system [39.5(7)(d) and (p) of the Act].

7.12.8 Monitoring Requirements

The Permittee shall perform the following monitoring pursuant to Sections 39.5(7)(a) and (d) of the Act.

a. The Permittee shall perform semi-annual inspections of the gasoline storage and dispensing operations at the storeroom, machine shop and blast furnace while the tank is being filled.

   i. Retractors, hoses, breakaways, swivels

   ii. Adapters, vapor caps, rubber gaskets, and spill containment buckets

b. The Permittee shall perform an annual inspection of the gasoline storage tank at wastewater facility and dispensing operation to ensure that a submerged loading pipe is physically present and the condition of the pipe for integrity.

7.12.9 Recordkeeping Requirements

The Permittee shall maintain records of the following items for the affected gasoline storage tanks, pursuant to Sections 39.5(7)(a) and (e) of the Act:

a. Records of the testing and repair of the vapor collection system and pressure/vacuum relief valves, pursuant to Condition 7.12.7.

b. Records of gasoline throughput (gallons per month and gallons per year).

c. For the affected gasoline storage tanks during the regulatory control period, the Permittee shall keep the following records:

i. Retain a copy of an invoice, bill of lading, or other documentation used in normal business practice stating that the Reid vapor pressure of the gasoline complies with the Reid vapor pressure standard as provided in 35 IAC 219.585(h)(1)(A);

ii. Maintain records on the Reid vapor pressure, quantity received and date of delivery of any gasoline or ethanol blends arriving at the gasoline operation [35 IAC 219.585(h)(2)].

d. Copies of the annual certification(s) from the supplier of gasoline that all the delivery vessels have been tested and are in compliance with the requirements of Condition 7.12.5(c).

e. A copy of operating and maintenance procedures and instructions for the tanks and vapor control systems.

f. Records for all inspections.

7.12.10 Reporting Requirements

a. i. Pursuant to Section 39.5(7)(f)(ii) of the Act, the Permittee shall promptly notify the Illinois EPA, Air Compliance Section, within 30 days of deviations by the affected gasoline storage tanks from applicable requirements, as follows:

A. Requirements in Condition 7.12.3(b) through (d).

B. Requirements in Condition 7.12.5(a) and (b).

ii. All such deviations shall be summarized and reported as part of the semiannual monitoring report required by Condition 8.6.1.

b. The Permittee shall notify the Illinois EPA, Air Compliance Section, of all other deviations as part of the semiannual monitoring reports required by Condition 8.6.1.

c. All deviation reports described in Condition 7.12.10 above shall contain the following:

i. Date, time and duration of the deviation;

ii. Description of the deviation;

iii. Probable cause of the deviation; and

iv. Any corrective action or preventive measures taken.

7.12.11 Operational Flexibility/Anticipated Operating Scenarios

Operational flexibility is not set for the affected gasoline storage tanks.

7.12.12 Compliance Procedures

For the affected gasoline storage tanks, compliance with the applicable standards of Condition 7.12.3 is addressed by the work practices, testing, monitoring, recordkeeping and reporting requirements described in Section 7.12 of this permit.

7.12.13 State-Only Conditions

State-only conditions are not being established.

7.13 Fugitive Dust

7.13.1 Description

Fugitive dust is emitted from vehicle traffic, unloading operations, wind erosion of piles, roadways, parking lots and other open areas at the facility. The source also emits fugitive dust from an on-site landfill for furnace dusts and other industrial wastes.

Note: This narrative description is for informational purposes only and is not enforceable.

7.13.2 List of Emission Units and Air Pollution Control Equipment

Emission Unit	Description	Date Constructed	Emission Control Equipment
Fugitive Emissions	Landfill Vehicular Traffic on Roadways, Parking Lots and Other Open Areas Unloading Operations Storage Piles and associated activities Beaching Areas	N/A	N/A

7.13.3 Applicable Provisions and Regulations

a. The "affected activities" for the purpose of these unit-specific conditions, are the activities described in Conditions 7.13.1 and 7.13.2 above.

b. The affected activities are subject to 35 IAC 212.306 which provides that all normal traffic pattern roads and parking facilities which are located on mining or manufacturing property shall be paved or treated with water, oils or chemical dust suppressants. All paved areas shall be cleaned on a regular basis. All areas treated with water, oils or chemical dust suppressants shall have the treatment applied on a regular basis, as needed, in accordance with the operating program required by 35 IAC 212.309, 212.310 and 212.312.

c. All storage piles of materials with uncontrolled emissions of fugitive particulate matter in excess of 45.4 Mg per year (50 T/yr) which are located within a source whose potential particulate emissions from all emission units exceed 90.8 Mg/yr (100 T/yr) shall be protected by a cover or sprayed with a surfactant solution or water on a regular basis, as needed, or treated by an equivalent method, in

accordance with the operating program required by 35 IAC 212.309, 212.310 and 212.312 of 35 IAC Part 212 Subpart K [35 IAC 212.304(a)].

d. Applicable emission limitations established by 35 IAC 212.316:

i. Emission Limitations for Storage Piles. No person shall cause or allow fugitive particulate matter emissions from any storage pile to exceed an opacity of 10 percent, to be measured four ft from the pile surface.

ii. Additional Emissions Limitations for the Granite City Vicinity as defined in 35 IAC 212.316(e)(1):

Emissions Limitations for Roadways or Parking Areas Located at Integrated Iron and Steel Manufacturing Plants. No person shall cause or allow fugitive particulate matter emissions from any roadway or parking area located at a slag processing facility or integrated iron and steel manufacturing plant to exceed an opacity of 5 percent.

iii. Pursuant to 35 IAC 212.316(f), emission limitation for all other activities (see the definition for emission unit in 35 IAC 211.1950). Unless an activity has been assigned a particulate matter, PM_{10}, or fugitive particulate matter emissions limitation elsewhere in 35 IAC 212.316 or in Subparts R or S of 35 IAC Part 212, no person shall cause or allow fugitive particulate matter emissions from any such activity to exceed an opacity of 20 percent.

e. All conveyor loading operations to storage piles specified in 35 IAC 212.304 shall utilize spray systems, telescopic chutes, stone ladders or other equivalent methods in accordance with the operating program required by 35 IAC 212.309, 212.310 and 212.312 [35 IAC 212.305].

7.13.4 Non-Applicability of Regulations of Concern

The landfill operated on the site is not subject to 35 IAC Part 220 for municipal waste landfills. The landfill serves only the needs for Permittee's operations in accepting industrial waste generated on-site and no municipal or any off-site waste is accepted by this landfill.

7.13.5 Control Requirements and Work Practices

a. Pursuant to permit #95010001 [T1], the Permittee shall comply with the following on-site and off-site fugitive dust control requirements:

i. On-site fugitive dust control

A. The Permittee shall sweep or flush at least every day the paved access area below the BOF ESP where ESP dust collection bags (i.e., super-sacks, storage bags or other containers for ESP dust) are used, stored and transported.

B. The Permittee shall implement a housekeeping program for the non-roadway areas below and around the BOF ESP. This program shall, at a minimum, contain the following:

1. The ground and other accessible areas where dust may gather shall be swept or cleaned at least every day;

2. Cleaning shall be performed in such a manner as to minimize the escape of dust into the atmosphere;

3. Dust collection bags shall be inspected at least daily for rips, tears, or insecure connection to the discharge of the ESP hoppers;

4. Dust collection bags shall be inspected after removal from, and connection to, the discharge of the ESP hoppers;

5. Ripped or torn bags shall be taken out of service and transported in a covered truck.

C. Unpaved Roads. For unpaved roads that are part of normal traffic patterns (including roads B, C, E, N, F-F, and CS(2)) the Permittee shall apply a chemical dust suppressant at least three times a month, with the following exceptions:

1. Road segment G-G, which shall be sprayed at least quarterly;

2. Road segment L, which shall be sprayed at least 4 times per month.

3. All other unpaved roads shall be treated as necessary.

4. Applications of suppressant may be less frequent than specified above if weather conditions, i.e., precipitation or temperature, interfere with the schedule for spraying, provided each such instance shall be recorded in accordance with the

daily records for on-site fugitive dust control required by Condition 7.13.9(b).

D. Paved roadways and areas. Paved roadways and areas shall be maintained in good condition by the Permittee.

On paved roadways and other areas, the Permittee shall sweep or flush as follows:

1. Road segments D, K, M, F, G, J, R, and O shall be swept or flushed at least daily;

2. Road segments P, V, W, X, Z, D-D, E-E, and CS(1) shall be swept or flushed at least five days per week;

3. Road segments S and T shall be swept or flushed at least every other day;

4. Road segments A and H shall be swept or flushed at least once per month;

5. All gate areas leading from the steelworks area shall be swept or flushed at least daily;

6. All gate areas leading from the iron making area shall be swept or flushed at least five times per week.

7. The above on-site dust control measures shall be conducted to maximize their effectiveness by performing said measures when the roads or areas are not obstructed by parked vehicles and by preferentially using filter sweeping (e.g., Enviro-Whirl sweeper) for the gate areas, the roads and areas surrounding the BOPF shop and BOF ESP.

b. The fugitive dust control measures outlined above do not relieve the Permittee from complying with additional control measures identified in the PM_{10} contingency plan as required by Condition 5.3.3 of this permit [95010001, T1R].

c. The landfill operated by the Permittee shall not accept any off-site wastes, including municipal, hospital/medical or hazardous wastes [Section 39.5(7)(l) of the Act].

d. Pursuant to the Road Cleaning Program required by Permit #06070088, the Permittee shall comply with the following control requirements (for purposes of this condition

affected road segments are those identified in Condition 7.13.5(d)(iii):

i. Good air pollution control practices shall be implemented to minimize and reduce nuisance dust from the affected road segments.

ii. Cleaning of affected road segments shall be performed using vacuum cleaning equipment (such as Enviro-Whirl). Any dust laden air shall be vented through a filtering system on the vacuum cleaning equipment before discharge to atmosphere.

The handling of material collected by vacuum cleaning equipment during road cleaning shall be enclosed or shall utilize spraying, pelletizing, screw conveying or other equivalent methods to control PM emissions from transfer of material for disposal.

iii. Affected road segments shall be cleaned on the following frequency except during extended periods of inclement weather that act to prevent emissions of fugitive dust from the affected road segments:

A. Cleaning on a twice weekly basis:

Road Segment	Segment Boundaries
Madison Ave	16th & 20th Streets
Central 20th Street	Madison St. & USS Gate
East 20th Street	USS Gate & Rte 203
21st Street	Rte 203 and Monroe St.
North Edwardsville Rd	20th & Nameoki (Rte 203)

B. Cleaning on a twice monthly basis:

Road Segment	Segment Boundaries
Rock Road	Rte 3 & W. 20th St. (Overpass Approach)
West 20th St.	Rte 3 & Rock Road
Rock Road	W. 20th & Benton St. (Railroad Overpass)
Niedringhaus	Benton St. and 16th St.
16th Street	Niedringhaus & Madison St.
South Edwardsville Rd	20th & McCambridge Ave (Rte 203)
McCambridge Ave	Edwardsville Rd (Rte 203) & 2nd St.
Route 162	Nameoki Rd (Rte 203) & Railroad Tracks
Benton Street	Rock Rd. and Niedringhaus

7.13.6 Production and Emission Limitations

Total fugitive emission of PM/PM_{10} from the roadways at the source shall not exceed 27 tons/year. Compliance with the

annual limits shall be determined based on a calendar year pursuant to Permit 95010001 [T1].

7.13.7 Testing Requirements

a. Opacity observations shall be conducted by a qualified observer in accordance with procedures published in 40 CFR Part 60, Appendix A, Method 9, except as specified below.

i. Opacity readings on each roadway or parking area shall be conducted at least annually. On unpaved roadways or parking areas, the reading shall not be conducted within three days of the application of any dust suppressants.

ii. The Permittee shall observe, one day per calendar month, the opacity of emissions from each active coal storage pile and areas travelled by equipment hauling coal from these coal storage piles to coal processing operations unless prolonged weather conditions preclude scheduled observations. In addition, the observer shall remain in the area for at least 3 hours to perform opacity readings on other coal piles which become active during this 3 hour period.

iii. All opacity readings conducted on visible emissions generated by vehicular traffic on roadways, parking areas and heavy equipment traffic associated with storage piles, shall be in accordance with the procedures specified in 35 IAC 212.109.

iv. All opacity readings on storage piles shall be measured four feet above the pile surface. The duration of opacity observations for each test shall be at least 30 minutes (five 6-minute averages) or 12 minutes without visible emissions.

b. Upon written request by the Illinois EPA, such testing shall be conducted for specific affected operations(s) within 45 calendar days of the request or on the date agreed upon by the Illinois EPA, whichever is later. As least 30 days prior to the scheduled test date, the Permittee shall submit a detailed test plan to the Illinois EPA, describing the manner of operations of the affected activity and all control measures that will be implemented during the testing. The results of the testing will be submitted within thirty calendar days of the completion of the tests.

c. The testing conditions from above are established in accordance with requirements of 39.5(7)(p) of the Act.

d. Pursuant to Permit 06070088, the Permittee shall conduct silt loading measurements as follows [T1] (for purposes of

this condition affected road segments are those identified in Condition 7.13.5(d)(iii)):

i. The Permittee shall conduct measurements of the silt loading on the affected road segments, with sampling and analysis conducted using the "Procedures for Sampling Surface/Bulk Dust Loading," Appendix C.1 in Compilation of Air Pollutant Emission Factors, USEPA, AP-42. A series of samples shall be taken to determine the average silt loading on each affected road segment and address the change in silt loadings as related to the amount and nature of vehicle traffic.

ii. Measurements for "controlled" silt loading shall be repeated at least every three years pursuant to the Road Cleaning Program of Condition 7.13.5(d).

iii. Measurements for "controlled" silt loadings shall be conducted upon written request by the Illinois EPA, as specified in the request, which shall be completed within 75 days of the Illinois EPA's request.

7.13.8 Monitoring Requirements

a. Except as provided in Condition 7.13.8(b), the Permittee shall perform inspections of the affected activities on at least a quarterly basis, including associated control measures, while the affected activities are in use, to confirm compliance with the requirements of Condition 7.13.3. Control measures may include material characteristics. These quarterly inspections may be scheduled so that only a number of affected activities are reviewed during each inspection, provided however, that all affected activities shall be inspected at least once during each calendar year. For the purpose of this condition, all affected activities means each type of material handled. (Sections 39.5(7)(a) and (d) of the Act).

b. The Permittee shall perform inspections, on a once per calendar month basis, during receipt of the truck unloading each contracted supply of coal.

c. As part of the inspections required by 7.13.8(a), the Permittee shall perform observations for visible emissions by Method 22. These observations shall be conducted during the operation of each activity for a minimum of 18 minutes, or for activities that operate on a batch basis, for a minimum of six consecutive batches. If visible emissions are observed, the Permittee shall take corrective action within 2 hours to return the status of the operation to no visible emissions or observations of opacity by Method 9 shall be conducted. For the purpose of this condition, returning the status of operations to no visible emissions

does not include, for any activity, temporary idling of lack of operation between batches.

d. The requirements from above are established pursuant to Sections 39.5(7)(a) and (d) of the Act.

7.13.9 Recordkeeping Requirements

The Permittee shall maintain records of the following items for the affected areas of fugitive emissions, pursuant to Sections 39.5(7)(a) and (e) of the Act:

a. Records required by 35 IAC 212.316(g):

i. The owner or operator of any fugitive particulate matter emission unit subject to 35 IAC 212.316 shall keep written records of the application of control measures for compliance with the opacity limitations of 212.316 and shall submit to the Illinois EPA an annual report containing a summary of such information.

ii. The records shall include at least the following:

A. The name and address of the source;

B. The name and address of the owner and/or operator of the source;

C. A map or diagram showing the location of all emission units controlled, including the location, identification, length, and width of roadways;

D. For each application of water or chemical solution to roadways by truck: the name and location of the roadway controlled, application rate of each truck, frequency of each application, width of each application, identification of each truck used, total quantity of water or chemical used for each application and, for each application of chemical solution, the concentration and identity of the chemical;

E. For application of physical or chemical control agents: the name of the agent, application rate and frequency, and total quantity of agent, and, if diluted, percent of concentration, used each day; and

F. A log recording incidents when control measures were not used and a statement of explanation.

iii. Copies of all records required by 35 IAC 212.316 shall be submitted to the Illinois EPA within ten (10) working days after a written request by the Illinois EPA and shall be transmitted to the Illinois EPA by a company-designated person with authority to release such records.

iv. The records required under 35 IAC 212.316 shall be kept and maintained for at least five (5) years at the source and be available for inspection and copying by Illinois EPA representatives during working hours.

b. i. The Permittee shall maintain daily records relative to the on-site fugitive dust control program which includes the following information at a minimum, pursuant to the Permit 95010001:

A. The date (and time for the gate areas) each road or area was treated;

B. The manner in which the road or area was treated (i.e., filter sweep, conventional sweep, suppressant spray or flush);

C. Detailed information for use of dust suppressant, including but not limited to the application rate, dilution ratio, type of suppressant used, and the number of gallons of suppressant applied;

D. Observations, if any, concerning the condition of the roadway, e.g., presence of parked vehicles, detection of potholes;

E. The amount of precipitation and temperature recorded for each day, and if determination was made to suspend application of suppressant, include name and title of person who made determination to suspend application and explanation; and

F. Any and all suspensions or deviations from the work practices and control procedures of Condition 7.13.5, with a date, description, and explanation for suspension of application.

ii. The Permittee shall keep a record containing calculations and analysis for the emissions from roadways at the source with emissions calculation performed in accordance with the methodology set forth in Section 13.2.1 of AP-42, to verify compliance with Condition 7.13.6. A copy of this record shall be submitted to the Illinois EPA each time it is prepared, with submittal made within 15

days of the date that the Permittee completes the preparation of new or revised calculations and analysis.

c. The Permittee shall maintain the most current versions of the PM_{10} contingency plan and the fugitive particulate matter control program.

d. The Permittee shall keep records of the silt measurements conducted pursuant to Condition 7.13.7(d), including records for the sampling and analysis activities and results.

e. Recordkeeping requirements for the Road Cleaning Program (for purposes of this condition affected road segments are those identified in Condition 7.13.5(d)(iii):

i. A. The Permittee shall keep a record describing the Road Cleaning Program that at a minimum: identify any contractors implementing the program for the Permittee and their duties for implementing the Program under the contract; the equipment used by the Permittee or its contractor for cleaning roads, including for each item of equipment, a description of and the manufacturer's specifications for collection of silt from roadways and control of dust emissions from the cleaning process; and the standards practices that are used to clean roads under the Program, such as type of equipment, and speed of travel.

B. The Permittee shall keep records for implementation of the Road Cleaning Program that at a minimum: Identify each time that an affected road segment was cleaned, with a description of any circumstances that may have affected the extent or nature of cleaning; and identify each time that scheduled cleaning was not performed, with detailed explanation.

C. The Permittee shall keep records documenting maintenance and repair of road cleaning equipment.

ii. The Permittee shall keep a record containing calculations and analysis for the annual reduction in emissions that is achieved by the Road Cleaning Program, with emissions calculation performed in accordance with the methodology set forth in Section 13.2.1 of AP-42, to verify that the Road Cleaning Program is achieving 236.03 tons/yr reduction, total, of particulate matter determined as PM_{10} from baseline emission levels of 656.87 tons/year from the affected road segments. This record shall be prepared in

conjunction with the measurements of "controlled" silt loadings required by Condition 7.13.7(d). A copy of this record shall be submitted to the Illinois EPA each time it is prepared, with submittal made to the Illinois EPA within 15 days of the date that the Permittee completes the preparation of new or revised calculations and analysis.

7.13.10 Reporting Requirements

The Permittee shall promptly notify the Illinois EPA, Air Compliance Section, of deviations of the affected area of fugitive emissions with the permit requirements, pursuant to Section 39.5(7)(f)(ii) of the Act. Reports submitted by the Permittee shall describe the probable cause of such deviations, and any corrective actions or preventive measures taken.

a. i. Pursuant 35 IAC 212.316(g)(5), the Permittee shall submit a quarterly report to the Illinois EPA stating the following: the dates any necessary control measures were not implemented, a listing of those control measures, the reasons that the control measures were not implemented, and any corrective actions taken. This information includes, but is not limited to, those dates when controls were not applied based on a belief that application of such control measures would have been unreasonable given prevailing atmospheric conditions, which shall constitute a defense to the requirements of 35 IAC 212.316. This report shall be submitted to the Agency thirty (30) calendar days from the end of a quarter. Quarters end March 31, June 30, September 30, and December 31.

ii. Pursuant to permit 06070088, the Permittee shall submit a quarterly report to the Illinois EPA describing the implementation of the Road Cleaning Program during the previous quarter. This report shall at a minimum provide: the number of times each road segment was cleaned; the number of times that cleaning was not performed, with explanation; a description of any significant changes in road cleaning equipment or cleaning practices, with explanation; and a description of other changes to the Road Cleaning Program, including changes in contractors.

b. i. Pursuant to Section 39.5(7)(f)(ii) of the Act, the Permittee shall promptly notify the Illinois EPA, Air Compliance Section, within 30 days of deviations in the affected areas of fugitive emissions, as follows:

A. Requirements in Condition 7.13.3(b) through (e).

B. Requirements in Condition 7.13.5.

C. Requirements in Condition 7.13.6.

ii. All such deviations shall be summarized and reported as part of the semiannual monitoring report required by Condition 8.6.1.

c. The Permittee shall notify the Illinois EPA, Air Compliance Section, of all other deviations as part of the semiannual monitoring reports required by Condition 8.6.1.

d. Deviation reports described in Condition 7.13.10(b) and (c) above shall contain the following:

i. Date, time and duration of the deviation;

ii. Description of the deviation;

iii. Probable cause of the deviation; and

iv. Any corrective action or preventive measures taken.

7.13.11 Operational Flexibility/Anticipated Operating Scenarios

a. Beaching

The following requirements established by Permits 72080034 and 72080036 shall be implemented:

i. Under the following circumstances beaching of iron may occur:

A. In the event that Blast Furnace A or Blast Furnace B must be shut down in order to cast the furnace dry.

B. In the event that an interruption in the BOF steelmaking and/or casting operations will result in a temporary surplus of iron, beyond the capacity of the system to hold, necessitating beaching in order to cast the furnace dry and provide the ability to safely shut down.

C. In the event that the blast furnace produces unusable iron such as high silica or low temperature iron. High silica iron shall be blended and used to the extent possible at the BOF in order to reduce beaching. Low temperature iron shall be used at the BOF to the extent possible until solidification in the car becomes imminent. In other cases of

unusable iron, such iron shall be used when possible to minimize the quantity beached.

ii. In the event that the beaching of iron occurs the Permittee shall beach the iron as follows:

A. Beaching shall be allowed only in the event that alternate receptacles are not available;

B. Beaching shall be allowed only if all reasonable measures are taken to minimize the quantity of liquid metal beached, the frequency of a malfunction or breakdown that necessitates beaching, the duration beaching occurs, and the emissions resulting from beaching; and

C. Beaching shall be allowed at a controlled pour rate not to exceed 20 tons per minute.

b. Prior to material in the beaching pit being dug and transferred to vehicles for recycling to the blast furnaces, it shall be watered or treated with other equivalent techniques to minimize particulate matter emissions during such material handling, unless such measures would cause a hazard or safety issue to employees.

7.13.12 Compliance Procedures

a. Compliance with Condition 7.13.3(b) is addressed by the monitoring requirements in Condition 7.13.8(b) and the records in Condition 7.13.9.

b. Compliance with Condition 7.13.3(c), (d), 7.13.5(a), (d), and 7.13.6 is addressed by the testing in Condition 7.13.7, monitoring requirements in Condition 7.13.8(a) and the records in Condition 7.13.9.

c. Compliance with Condition 7.13.3(e) is addressed by the testing requirements Condition 7.13.7, monitoring in Condition 7.13.8(c) and the records in Condition 7.13.9.

d. Compliance with Condition 7.13.5(c) is addressed by the records in Condition 7.13.9.

7.13.13 State-Only Conditions

State-only conditions are not being established.

8.0 GENERAL PERMIT CONDITIONS

8.1 Permit Shield

Pursuant to Section 39.5(7)(j) of the Act, the Permittee has requested and has been granted a permit shield. This permit shield provides that compliance with the conditions of this permit shall be deemed compliance with applicable requirements which were applicable as of the date the proposed permit for this source was issued, provided that either the applicable requirements are specifically identified within this permit, or the Illinois EPA, in acting on this permit application, has determined that other requirements specifically identified are not applicable to this source and this determination (or a concise summary thereof) is included in this permit.

This permit shield does not extend to applicable requirements which are promulgated after May 2, 2011, unless this permit has been modified to reflect such new requirements.

8.2 Applicability of Title IV Requirements (Acid Deposition Control)

This source is not an affected source under Title IV of the CAA and is not subject to requirements pursuant to Title IV of the CAA.

8.3 Emissions Trading Programs

No permit revision shall be required for increases in emissions allowed under any USEPA approved economic incentives, marketable permits, emissions trading, and other similar programs or processes for changes that are provided for elsewhere in this permit and that are authorized by the applicable requirement [Section 39.5(7)(o)(vii) of the Act].

8.4 Operational Flexibility/Anticipated Operating Scenarios

8.4.1 Changes Specifically Addressed by Permit

Physical or operational changes specifically addressed by the conditions of this permit that have been identified as not requiring Illinois EPA notification may be implemented without prior notice to the Illinois EPA.

8.4.2 Changes Requiring Prior Notification

The Permittee is authorized to make physical or operational changes that contravene express permit terms without applying for or obtaining an amendment to this permit, provided that [Section 39.5(12)(a)(i) of the Act]:

a. The changes do not violate applicable requirements;

b. The changes do not contravene federally enforceable permit terms or conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements;

c. The changes do not constitute a modification under Title I of the CAA;

d. Emissions will not exceed the emissions allowed under this permit following implementation of the physical or operational change; and

e. The Permittee provides written notice to the Illinois EPA, Division of Air Pollution Control, Permit Section, at least 7 days before commencement of the change. This notice shall:

i. Describe the physical or operational change;

ii. Identify the schedule for implementing the physical or operational change;

iii. Provide a statement of whether or not any New Source Performance Standard (NSPS) is applicable to the physical or operational change and the reason why the NSPS does or does not apply;

iv. Provide emission calculations which demonstrate that the physical or operational change will not result in a modification; and

v. Provide a certification that the physical or operational change will not result in emissions greater than authorized under the conditions of this permit.

8.5 Testing Procedures

Tests conducted to measure composition of materials, efficiency of pollution control devices, emissions from process or control equipment, or other parameters shall be conducted using standard test methods if applicable test methods are not specified by the applicable regulations or otherwise identified in the conditions of this permit. Documentation of the test date, conditions, methodologies, calculations, and test results shall be retained pursuant to the recordkeeping procedures of this permit. Reports of any tests conducted as required by this permit or as the result of a request by the Illinois EPA shall be submitted as specified in Conditions 8.6.3 and 8.6.4.

8.6 Reporting Requirements

8.6.1 Monitoring Reports

Semiannual reports, including monitoring reports summarizing required monitoring as specified in the conditions of this permit shall be submitted to the Illinois EPA, unless more frequent submittal of such reports is required in Sections 5 or 7 of this permit [Section 39.5(7)(f) of the Act]:

Monitoring Period	Report Due Date
January - June	July 31
July - December	January 31

All instances of deviations from permit requirements must be clearly identified in such reports. All such reports shall be certified in accordance with Condition 9.9.

8.6.2 Test Notifications

Unless otherwise specified elsewhere in this permit, a written test plan for any test required by this permit shall be submitted to the Illinois EPA for review at least 60 days prior to the testing pursuant to Section 39.5(7)(a) of the Act. The notification shall include at a minimum:

a. The name and identification of the affected unit(s);

b. The person(s) who will be performing sampling and analysis and their experience with similar tests;

c. The specific conditions under which testing will be performed, including a discussion of why these conditions will be representative of maximum emissions and the means by which the specified operating parameters, as defined in Section 7 for each emission unit and any control equipment, will be determined;

d. The specific determinations of emissions and operation that are intended to be made, including sampling and monitoring locations;

e. The test method(s) that will be used, with the specific analysis method, if the method can be used with different analysis methods;

f. Any minor changes in standard methodology proposed to accommodate the specific circumstances of testing, with justification; and

g. Any proposed use of an alternative test method, with detailed justification.

8.6.3 Test Reports

Unless otherwise specified elsewhere in this permit, the results of any test required by this permit shall be submitted to the Illinois EPA within 60 days of completion of the testing. The test report shall include at a minimum [Section 39.5(7)(e)(i) of the Act]:

a. The name and identification of the affected unit(s);

b. The date and time of the sampling or measurements;

c. The date any analyses were performed;

d. The name of the company that performed the tests and/or analyses;

e. The test and analytical methodologies used;

f. The results of the tests including raw data, and/or analyses including sample calculations;

g. The operating conditions at the time of the sampling or measurements; and

h. The name of any relevant observers present including the testing company's representatives, any Illinois EPA or USEPA representatives, and the representatives of the source.

8.6.4 Reporting Addresses

a. Unless otherwise specified in the particular provision of this permit or in the written instructions distributed by the Illinois EPA for particular reports, reports and notifications shall be sent to the Illinois EPA - Air Compliance Unit with a copy sent to the Illinois EPA - Air Regional Field Office.

b. All test protocols, test notifications and test reports shall be sent to the Illinois EPA - Air Compliance Unit with a copy sent to the Illinois EPA - Air Regional Field Office and to the Illinois EPA - Stack Test Specialist.

c. As of the date of issuance of this permit, the addresses of the offices that should generally be utilized for the submittal of reports and notifications are as follows:

i. Illinois EPA - Air Compliance Unit

Illinois Environmental Protection Agency
Bureau of Air
Compliance & Enforcement Section (MC 40)
1021 North Grand Avenue East
P.O. Box 19276
Springfield, Illinois 62794-9276

ii. Illinois EPA - Stack Test Specialist

Illinois Environmental Protection Agency
Division of Air Pollution Control
9511 West Harrison
Des Plaines, Illinois 60016

iii. Illinois EPA - Air Quality Planning Section

Illinois Environmental Protection Agency
Bureau of Air

Air Quality Planning Section (MC 39)
1021 North Grand Avenue East
P.O. Box 19276
Springfield, Illinois 62794-9276

iv. Illinois EPA - Air Regional Field Office

Illinois Environmental Protection Agency
Division of Air Pollution Control
2009 Mall Street
Collinsville, Illinois 62234

v. USEPA Region 5 - Air Branch

USEPA (AR - 17J)
Air & Radiation Division
77 West Jackson Boulevard
Chicago, Illinois 60604

d. Permit applications should be addressed to the Air Permit Section. As of the date of issuance of this permit, the address of the Air Permit Section is as follows:

Illinois Environmental Protection Agency
Division of Air Pollution Control
Permit Section (MC 11)
1021 North Grand Avenue East
P.O. Box 19506
Springfield, Illinois 62794-9506

8.7 Title I Conditions

Notwithstanding the expiration date on the first page of this CAAPP permit, Title I conditions in this permit, which are identified by a T1, T1N, or T1R designation, remain in effect until such time as the Illinois EPA takes action to revise or terminate them in accordance with applicable procedures for action on Title I conditions. This is because these conditions either: (a) incorporate conditions of earlier permits that were issued by the Illinois EPA pursuant to authority that includes authority found in Title I of the CAA (T1 conditions), (b) were newly established in this CAAPP permit pursuant to authority that includes such Title I authority (T1N conditions), or (c) reflect a revision or combination of conditions established in this CAAPP permit (T1R conditions). (See also Condition 1.5.)

9.0 STANDARD PERMIT CONDITIONS

9.1 Effect of Permit

9.1.1 The issuance of this permit does not release the Permittee from compliance with State and Federal regulations which are part of the Illinois State Implementation Plan, as well as with other applicable statutes and regulations of the United States or the State of Illinois or applicable ordinances, except as specifically stated in this permit and as allowed by law and rule.

9.1.2 In particular, this permit does not alter or affect the following [Section 39.5(7)(j)(iv) of the Act]:

a. The provisions of Section 303 (emergency powers) of the CAA, including USEPA's authority under that Section;

b. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

c. The applicable requirements of the acid rain program consistent with Section 408(a) of the CAA; and

d. The ability of USEPA to obtain information from a source pursuant to Section 114 (inspections, monitoring, and entry) of the CAA.

9.1.3 This permit and the terms and conditions herein do not affect the Permittee's past and/or continuing obligation with respect to statutory or regulatory requirements governing major source construction or modification under Title I of the CAA. Further, neither the issuance of this permit nor any of the terms or conditions of the permit shall alter or affect the liability of the Permittee for any violation of applicable requirements prior to or at the time of permit issuance.

9.1.4 Except as provided by applicable law, the issuance of this permit by the Illinois EPA does not and shall not be construed as barring, diminishing, adjudicating or in any way affecting any currently pending or future legal, administrative or equitable rights or claims, actions, suits, causes of action or demands whatsoever that the Illinois EPA or the USEPA may have against the applicant including, but not limited to, any enforcement action authorized pursuant to the provision of applicable federal and state law.

9.1.5 Notwithstanding the conditions of this permit specifying compliance practices for applicable requirements, pursuant to Section 39.5(7)(j) and (p) of the Act, any person (including the Permittee) may also use other credible evidence to establish compliance or noncompliance with applicable requirements.

9.1.6 In the event of an action to enforce the terms or conditions of this permit, this permit does not prohibit a Permittee from invoking any affirmative defense that is provided by the applicable law or rule.

9.2 General Obligations of Permittee

9.2.1 Duty to Comply

The Permittee must comply with all terms and conditions of this permit. Any permit noncompliance constitutes a violation of the CAA and the Act, and is grounds for any or all of the following: enforcement action; permit termination, revocation and reissuance, or modification; or denial of a permit renewal application [Section 39.5(7)(o)(i) of the Act].

The Permittee shall meet applicable requirements that become effective during the permit term in a timely manner unless an alternate schedule for compliance with the applicable requirement is established.

9.2.2 Duty to Maintain Equipment

The Permittee shall maintain all equipment covered under this permit in such a manner that the performance or operation of such equipment shall not cause a violation of applicable requirements.

9.2.3 Duty to Cease Operation

No person shall cause, threaten or allow the continued operation of any emission unit during malfunction or breakdown of the emission unit or related air pollution control equipment if such operation would cause a violation of an applicable emission standard, regulatory requirement, ambient air quality standard or permit limitation unless this permit provides for such continued operation consistent with the Act and applicable Illinois Pollution Control Board regulations [Section 39.5(6)(c) of the Act].

9.2.4 Disposal Operations

The source shall be operated in such a manner that the disposal of air contaminants collected by the equipment operations, or activities shall not cause a violation of the Act or regulations promulgated there under.

9.2.5 Duty to Pay Fees

The Permittee must pay fees to the Illinois EPA consistent with the fee schedule approved pursuant to Section 39.5(18) of the Act, and submit any information relevant thereto [Section 39.5(7)(o)(vi) of the Act]. The check should be payable to "Treasurer, State of Illinois" and sent to: Fiscal Services

Section, Illinois Environmental Protection Agency, P.O. Box 19276, Springfield, Illinois, 62794-9276.

9.3 Obligation to Allow Illinois EPA Surveillance

Upon presentation of proper credentials and other documents as may be required by law and in accordance with constitutional limitations, the Permittee shall allow the Illinois EPA, or an authorized representative to perform the following [Sections 4 and 39.5(7)(a) and (p)(ii) of the Act]:

a. Enter upon the Permittee's premises where an actual or potential emission unit is located; where any regulated equipment, operation, or activity is located or where records must be kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

c. Inspect during hours of operation any sources, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;

d. Sample or monitor any substances or parameters at any location:

i. At reasonable times, for the purposes of assuring permit compliance or applicable requirements; or

ii. As otherwise authorized by the CAA, or the Act.

e. Obtain and remove samples of any discharge or emission of pollutants authorized by this permit; and

f. Enter and utilize any photographic, recording, testing, monitoring, or other equipment for the purposes of preserving, testing, monitoring, or recording any activity, discharge or emission at the source authorized by this permit.

9.4 Obligation to Comply with Other Requirements

The issuance of this permit does not release the Permittee from applicable State and Federal laws and regulations, and applicable local ordinances addressing subjects other than air pollution control.

9.5 Liability

9.5.1 Title

This permit shall not be considered as in any manner affecting the title of the premises upon which the permitted source is located.

9.5.2 Liability of Permittee

This permit does not release the Permittee from any liability for damage to person or property caused by or resulting from the construction, maintenance, or operation of the sources.

9.5.3 Structural Stability

This permit does not take into consideration or attest to the structural stability of any unit or part of the source.

9.5.4 Illinois EPA Liability

This permit in no manner implies or suggests that the Illinois EPA (or its officers, agents or employees) assumes any liability, directly or indirectly, for any loss due to damage, installation, maintenance, or operation of the source.

9.5.5 Property Rights

This permit does not convey any property rights of any sort, or any exclusive privilege [Section 39.5(7)(o)(iv) of the Act].

9.6 Recordkeeping

9.6.1 Control Equipment Maintenance Records

A maintenance record shall be kept on the premises for each item of air pollution control equipment. At a minimum, this record shall show the dates of performance and nature of preventative maintenance activities.

9.6.2 Records of Changes in Operation

A record shall be kept describing changes made at the source that result in emissions of a regulated air pollutant subject to an applicable Clean Air Act requirement, but not otherwise regulated under this permit, and the emissions resulting from those changes [Section 39.5(12)(b)(iv) of the Act].

9.6.3 Retention of Records

a. Records of all monitoring data and support information shall be retained for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records, original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit [Section 39.5(7)(e)(ii) of the Act].

b. Other records required by this permit including any logs, plans, procedures, or instructions required to be kept by this permit shall be retained for a period of at least 5

years from the date of entry unless a longer period is specified by a particular permit provision.

9.7 Annual Emissions Report

The Permittee shall submit an annual emissions report to the Illinois EPA, Air Quality Planning Section no later than May 1 of the following year, as required by 35 IAC Part 254.

9.8 Requirements for Compliance Certification

Pursuant to Section 39.5(7)(p)(v) of the Act, the Permittee shall submit annual compliance certifications. The compliance certifications shall be submitted no later than May 1 or more frequently as specified in the applicable requirements or by permit condition. The compliance certifications shall be submitted to the Air Compliance Unit, Air Regional Field Office, and USEPA Region 5 - Air Branch. The addresses for the submittal of the compliance certifications are provided in Condition 8.6.4 of this permit.

a. The certification shall include the identification of each term or condition of this permit that is the basis of the certification; the compliance status; whether compliance was continuous or intermittent; the method(s) used for determining the compliance status of the source, both currently and over the reporting period consistent with the conditions of this permit.

b. All compliance certifications shall be submitted to USEPA Region 5 in Chicago as well as to the Illinois EPA.

c. All compliance reports required to be submitted shall include a certification in accordance with Condition 9.9.

9.9 Certification

Any document (including reports) required to be submitted by this permit shall contain a certification by a responsible official of the Permittee that meets the requirements of Section 39.5(5) of the Act and applicable regulations [Section 39.5(7)(p)(i) of the Act]. An example Certification by a Responsible Official is included as Attachment 1 to this permit.

9.10 Defense to Enforcement Actions

9.10.1 Need to Halt or Reduce Activity Not a Defense

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 [Section 39.5(7)(o)(ii) of the Act].

9.10.2 Emergency Provision

a. An emergency shall be an affirmative defense to an action brought for noncompliance with the technology-based emission limitations under this permit if the following conditions are met through properly signed, contemporaneous operating logs, or other relevant evidence [Section 39.5(7)(k) of the Act]:

i. An emergency occurred as provided in Section 39.5(7)(k) of the Act and the Permittee can identify the cause(s) of the emergency.

Note: For this purpose, emergency means a situation arising from sudden and reasonably unforeseeable events beyond the control of the source, as further defined by Section 39.5(7)(k)(iv) of the Act.

ii. The permitted source was at the time being properly operated;

iii. The Permittee submitted notice of the emergency to the Illinois EPA within two working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a detailed description of the emergency, any steps taken to mitigate emissions, and corrective actions taken; and

iv. During the period of the emergency the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission limitations, standards, or regulations in this permit.

b. This provision is in addition to any emergency or upset provision contained in any applicable requirement. This provision does not relieve a Permittee of any reporting obligations under existing federal or state laws or regulations [Section 39.5(7)(k)(iv) of the Act].

9.11 Permanent Shutdown

This permit only covers emission units and control equipment while physically present at the indicated source location(s). Unless this permit specifically provides for equipment relocation, this permit is void for the operation or activity of any item of equipment on the date it is removed from the permitted location(s) or permanently shut down. This permit expires if all equipment is removed from the permitted location(s), notwithstanding the expiration date specified on this permit.

9.12 Reopening and Reissuing Permit for Cause

9.12.1 Permit Actions

This permit may be modified, revoked, reopened and reissued, or terminated for cause in accordance with applicable provisions of Section 39.5 of the Act. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition [Section 39.5(7)(o)(iii) of the Act].

9.12.2 Reopening and Revision

This permit must be reopened and revised if any of the following occur [Section 39.5(15)(a) of the Act]:

a. Additional requirements become applicable to the equipment covered by this permit and three or more years remain before expiration of this permit.

b. Additional requirements become applicable to an affected source for acid deposition under the acid rain program.

c. The Illinois EPA or USEPA determines that this permit contains a material mistake or that inaccurate statement were made in establishing the emission standards or limitations, or other terms or conditions of this permit.

d. The Illinois EPA or USEPA determines that this permit must be revised or revoked to ensure compliance with the applicable requirements.

9.12.3 Inaccurate Application

The Illinois EPA has issued this permit based upon the information submitted by the Permittee in the permit application. Any misinformation, false statement or misrepresentation in the application shall be grounds for revocation and reissuance under Section 39.5(15) of the Act, pursuant to Sections 39.5(5)(e) and (i) of the Act.

9.12.4 Duty to Provide Information

The Permittee shall furnish to the Illinois EPA, within a reasonable time specified by the Illinois EPA any information that the Illinois EPA 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 the Illinois EPA copies of records required to be kept by this permit, or for information claimed to be confidential, the Permittee may furnish such records directly to USEPA along with a claim of confidentiality [Section 39.5(7)(o)(v) of the Act].

9.13 Severability Clause

The provisions of this permit are severable. In the event of a challenge to any portion of the permit, other portions of the permit may continue to be in effect. Should any portion of this permit be determined to be illegal or unenforceable, the validity of the other provisions shall not be affected and the rights and obligations of the Permittee shall be construed and enforced as if this permit did not contain the particular provisions held to be invalid and the applicable requirements underlying these provisions shall remain in force [Section 39.5(7)(i) of the Act].

9.14 Permit Expiration and Renewal

Upon the expiration of this permit, if the source is operated, it shall be deemed to be operating without a permit unless a timely and complete CAAPP application has been submitted for renewal of this permit. However, if a timely and complete application to renew this CAAPP permit has been submitted, the terms and all conditions of this CAAPP permit will remain in effect until the issuance of a renewal permit [Section 39.5(5)(l) and (o) of the Act].

Note: Pursuant to Sections 39.5(5)(h) and (n) of the Act, upon submittal of a timely and complete renewal application, the permitted source may continue to operate until final action is taken by the Illinois EPA on the renewal application, provided, however, that this protection shall cease if the applicant fails to submit any additional information necessary to evaluate or take final action on the renewal application as requested by the Illinois EPA in writing. For a renewal application to be timely, it must be submitted no later than 9 months prior to the date of permit expiration.

9.15 General Authority for the Terms and Conditions of this Permit

The authority for terms and conditions of this permit that do not include a citation for their authority is Section 39.5(7)(a) of the Act, which provides that the Illinois EPA shall include such provisions in a CAAPP permit as are necessary to accomplish the purposes of the Act and to assure compliance with all applicable requirements. Section 39.5(7)(a) of the Act is also another basis of authority for terms and conditions of this permit that do include a specific citation for their authority.

Note: This condition is included in this permit pursuant to Section 39.5(7)(n) of the Act.

10.0 ATTACHMENTS

Attachment 1 Example Certification by a Responsible Official

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Signature: _____

Name: _____

Official Title: _____

Telephone No.: _____

Date Signed: _____

Attachment 2 Emissions of Particulate Matter from Process Emission Units

10.2.1. Process Emission Units for Which Construction or Modification Commenced On or After April 14, 1972

a. New Process Emission Units for Which Construction or Modification Commenced On or After April 14, 1972 [35 IAC 212.321].

b. No person shall cause or allow the emission of particulate matter into the atmosphere in any one hour period from any new process emission unit, either alone or in combination with the emission of particulate matter from all other similar process emission units for which construction or modification commenced on or after April 14, 1972, at a source or premises, exceeds the allowable emission rates specified in subsection (c) of 35 IAC 212.321 [35 IAC 212.321(a)].

i. The emissions of particulate matter into the atmosphere in any one hour period from the affected coating lines shall not exceed the allowable emission rates specified in the following equation:

$$E = A\ (P)^B$$

Where:

P = Process weight rate

E = Allowable emission rate

ii. For process weight rates of 408 Mg/hr (450 T/hr):

	Metric	English
P	Mg/hr	T/hr
E	kg/hr	lbs/hr
A	1.214	2.54
B	0.534	0.534

iii. For process weight rates in excess of 408 Mg/hr (450 T/hr):

	Metric	English
P	Mg/hr	T/hr
E	kg/hr	lbs/hr
A	11.42	24.8
B	0.16	0.16

c. Limits for Process Emission Units for which Construction or Modification Commenced On or After April 14, 1972 [35 IAC 212.321(c)]:

Metric		English	
P	E	P	E
Mg/hr	kg/hr	T/hr	lb/hr
0.05	0.25	0.05	0.55
0.1	0.29	0.10	0.77
0.2	0.42	0.2	1.10
0.3	0.64	0.30	1.35
0.4	0.74	0.40	1.58
0.5	0.84	0.50	1.75
0.7	1.00	0.75	2.40
0.9	1.15	1.00	2.60
1.8	1.66	2.00	3.70
2.7	2.1	3.00	4.60
3.6	2.4	4.00	5.35
4.5	2.7	5.00	6.00
9.0	3.9	10.00	8.70
13.0	4.8	15.00	10.80
18.0	5.7	20.00	12.50
23.0	6.5	25.00	14.00
27.0	7.1	30.00	15.60
32.0	7.7	35.00	17.00
36.0	8.2	40.00	18.20
41.0	8.8	45.00	19.20
45.0	9.3	50.00	20.50
90.0	13.4	100.00	29.50
140.0	17.0	150.00	37.00
180.0	19.4	200.00	43.00
230.0	22.0	250.00	48.50
270.0	24.0	300.00	53.00
320.0	26.0	350.00	58.00
360.0	28.0	400.00	62.00
408.0	30.1	450.00	66.00
454.0	30.4	500.00	67.00

10.2.2 Process Emission Units for Which Construction or Modification Commenced Prior to April 14, 1972

a. No person shall cause or allow the emission of particulate matter into the atmosphere in any one hour period from any new process emission unit, either alone or in combination with the emission of particulate matter from all other similar process emission units for which construction or modification commenced prior to April 14, 1972, at a source or premises, exceeds the allowable emission rates specified in subsection (c) of 35 IAC 212.322 [35 IAC 212.322(a)].

b. The emissions of particulate matter into the atmosphere in any one hour period from the affected unit shall not exceed the allowable emission rates specified in the following equation:

$$E = C + A\ (P)^B$$

Where:

P = Process weight rate

E = Allowable emission rate

i. For process weight rates up to 27.2 Mg/hr (30 T/hr):

	Metric	English
P	Mg/hr	T/hr
E	kg/hr	lbs/hr
A	1.985	4.10
B	0.67	0.67
C	0	0

ii. For process weight rates in excess of 27.2 Mg/hr (30 T/hr):

	Metric	English
P	Mg/hr	T/hr
E	kg/hr	lbs/hr
A	25.21	55.0
B	0.11	0.11
C	-18.4	-40.0

c. Limits for Process Emission Units for which Construction or Modification Commenced Prior to April 14, 1972 [35 IAC 212.322(c)]:

Metric		English	
P	E	P	E
Mg/hr	kg/hr	T/hr	lb/hr
0.05	0.27	0.05	0.55
0.1	0.42	0.10	0.87
0.2	0.68	0.20	1.40
0.3	0.89	0.30	1.83
0.4	1.07	0.40	2.22
0.5	1.25	0.50	2.58
0.7	1.56	0.75	3.38
0.9	1.85	1.00	4.10
1.8	2.9	2.00	6.52
2.7	3.9	3.00	8.56
3.6	4.7	4.00	10.40
4.5	5.4	5.00	12.00
9.0	8.7	10.00	19.20
13.0	11.1	15.00	25.20
18.0	13.8	20.00	30.50
23.0	16.2	25.00	35.40
27.2	18.15	30.00	40.00
32.0	18.8	35.00	41.30
36.0	19.3	40.00	42.50
41.0	19.8	45.00	43.60
45.0	20.2	50.00	44.60
90.0	23.2	100.00	51.20
140.0	25.3	150.00	55.40
180.0	26.5	200.00	58.60
230.0	27.7	250.00	61.00
270.0	28.5	300.00	63.10
320.0	29.4	350.00	64.90
360.0	30.0	400.00	66.20
400.0	30.6	450.00	67.70
454.0	31.3	500.00	69.00

Attachment 3 Current Emission Factors for Certain Emission Limits

This attachment provides information, based on information provided by the Permittee as of the date of issuance of this revised permit, on the emission factors used by the Permittee to demonstrate compliance with certain emission limits for Material Handling Operations (Section 7.1), Blast Furnace Operations (Section 7.4), Basic Oxygen Process Operations (Section 7.5) and Continuous Casting Activities (Section 7.6), which limits have been carried over from Construction Permit/PSD Approval 95010001. (See also Condition 5.13.)

Operation (Permit Condition)	Pollutant	Emission Factor	Basis
Material Handling Operations (Section 7.1)			
Ladle Metallurgy Material Handling (7.1.6(b)(i))	PM	0.00355 lb/ton	steel
	PM10	0.00355 lb/ton	steel
BOF Additive System (7.1.6(b)(ii))	PM	0.00032 lb/ton	steel
	PM10	0.00032 lb/ton	steel
Flux conveyor Operations (7.1.6(b)(iii))	PM	0.0016 lb/ton	steel
	PM10	0.0016 lb/ton	steel
Iron Pellet Screening (7.1.6(b)(iv))	PM	0.00279 lb/ton	iron pellets
	PM10	0.00279 lb/ton	iron pellets
Blast Furnace Operations (Section 7.4)			
Casthouse (7.4.6(b))	PM	0.0703 lb/ton	iron
	PM_{10}	0.0703 lb/ton	iron
	SO_2	0.2006 lb/ton	iron
	NO_x	0.0144 lb/ton	iron
	VOM	0.0946 lb/ton	iron
Blast Furnace Uncaptured Emissions (7.4.6(c))	PM	0.031 lb/ton	iron
	PM_{10}	0.0155 lb/ton	iron
	SO_2	0.0104 lb/ton	iron
	NO_x	0.0007 lb/ton	iron
	VOM	0.0047 lb/ton	iron
Blast Furnace Charging (7.4.6(d))	PM	0.0024 lb/ton	iron pellets
	PM_{10}	0.0024 lb/ton	iron pellets
Slag Pits (7.4.6(e))	PM	0.00417 lb/ton	iron
	PM_{10}	0.00417 lb/ton	iron
	SO_2	0.01 lb/ton	iron
Iron Spout (7.4.6(f))	PM	0.02548 lb/ton	iron
	PM_{10}	0.02548 lb/ton	iron
	SO_2	0.0073 lb/ton	iron

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Operation (Permit Condition)	Pollutant	Emission Factor	Basis
Basic Oxygen Process Operations (Section 7.5)			
BOF Electrostatic Precipitator (7.5.6(c))	PM	0.16 lb/ton	steel
	PM_{10}	0.16 lb/ton	steel
	NO_x	0.0389 lb/ton*	steel
	VOM	0.006 lb/ton**	steel
	CO	8.993 lb/ton	steel
	Lead	0.1934 lb/hr	-
BOF Roof Monitor (7.5.6(d))	PM	0.0987 lb/ton	steel
	PM_{10}	0.066145 lb/ton	steel
	Lead	0.0129 lb/hour	-
Desulfurization and Hot Metal Transfer (7.5.6(e))	PM	0.03721 lb/ton	iron
	PM_{10}	0.03721 lb/ton	iron
	VOM	0.001 lb/ton	iron
	Lead	0.0133 lb/hr	-
Slag Skimming (7.5.6(f))	PM	0.005 lb/ton	iron
	PM_{10}	0.005 lb/ton	iron
Argon Stirring and Material Handling (7.5.6(g))	PM	0.00715 lb/ton	steel
	PM_{10}	0.00715 lb/ton	steel
Continuous Casting Activities (Section 7.6)			
Baghouse #1 (7.6.6(a))	PM	0.00355 lb/ton	steel
	PM_{10}	0.00355 lb/ton	steel
Continuous Caster Molds (7.6.6(b))	PM	0.006 lb/ton	steel
	PM_{10}	0.006 lb/ton	steel
	NO_x	0.05 lb/ton	steel
Cont. Caster Spray Chambers (7.6.6(c))	PM	0.00852 lb/ton	steel
	PM_{10}	0.00852 lb/ton	steel
Slab Cutoff (7.6.6(d))	PM	0.0071 lb/ton	steel
	PM_{10}	0.0071 lb/ton	steel
Slab Ripping (7.6.6(e))	PM	0.00722 lb/ton	steel
	PM_{10}	0.00722 lb/ton	steel

* As of the date of issuance of this permit, the Permittee had not notified the Illinois EPA of the updated NOx emission factor that it will be using for the BOF ESP as a consequence of the results of recent testing that indicated that a factor of 0.0389 pounds/ton would understate actual emissions. The NOx emission rates measured during such testing, in April 2012 and July 2012, were, respectively, 0.1273 and 0.1535 pounds per ton of steel.

** As of the date of issuance of this permit, the Permittee had not notified the Illinois EPA of the updated VOM emission factor that it will be using for the BOF ESP as a consequence of the results of recent testing that indicated that a factor of 0.006 pounds/ton would understate actual emissions. The VOM emission rates measured during such testing in April 2012 and July 2012, respectively, were 0.023 and 0.0153 pounds per ton of steel.

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Appendix A

Summary of Public Notification Process

PIMA COUNTY
ENVIRONMENTAL QUALITY

Outreach for Tucson Electric Power PSD Permit

Objective: Inform community about proposed modification to TEP air quality permit and associated public meetings and public comment period

Key PDEQ Staff
Ursula Nelson - Director
Richard Grimaldi - Deputy Director
Rupesh Patel - Environmental Quality Manager
Scott Porter - Environmental Quality Manager
Dustin Fitzpatrick - Compliance Manager
Mellanie Fuller - Environmental Permitting Manager
Beth Gorman - Senior Program Manager, Public Outreach & Community Education
Karen Wilhelmsen - Program Manager, Community Outreach & Education
Kimberly Baeza - Environmental Compliance Specialist (English/Spanish translator at Open House)
Nora Alonso - RCRA Compliance Inspector (English/Spanish translator at Public Hearing #1)
Marie Light – Stormwater Program Manager (English/Spanish translator at Public Hearing #2))

Key Stakeholders
TEP Area Residents and Businesses
Tucson Area Community
National Park Service
U.S. Environmental Protection Agency
Sierra Club

Legally Required Public Notifications

PDEQ Receipt of Complete Application from TEP to Make Major Modification of Existing Major Source
- October 2, 2017: Single day notice public notice, AZ Daily Star

Draft Prevention of Significant Deterioration Air Quality Permit
- AZ Daily Star Public Notice
  - February 9, 2018: First notice
  - February 16, 2018: Second notice
- Tucson Newspaper (TNI) Daily Territorial Public Notice
  - February 9, 2018: First notice
  - February 16, 2018: Second notice

Extended Comment Period
- AZ Daily Star Public Notice
  - February 26, 2018: First notice
  - March 5, 2018: Second notice

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conservative demonstration that the RICE project will not cause or contribute to a violation of the ozone NAAQS, and have not updated the final TSD to include additional photochemical modeling.

V. Comment:
TEP's statement (in the Permit Application Section 4.11- Modeling of Ozone Precursors), that "… if the project emissions are expected to have an impact below the ozone SIL, then its emissions are not expected to cause or contribute to an ozone NAAQS violation" is not supported and is not credible after the year 2015, during which DEQ called ozone alerts for 12 days, and in which NAAQS limits were exceeded at every monitoring station in the County during that year. TEP also stated that "The only ozone nonattainment area in Arizona is located in Maricopa County" is inaccurate, as Pinal County, which is closer to Tucson than Maricopa County, also contains nonattainment areas.

Response:
We disagree with the commenter's assertion that calendar year 2015 ozone monitoring results affects the credibility of the modeling analysis contained in the Proposed TSD. While ambient monitoring stations in Pima County have recorded exceedances of the ozone standard, a violation of the ozone standard is determined based upon the form of the standard. For both the primary and secondary ozone NAAQS, the form of the standard is the annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years. At this time, this represents 0.069 ppm (69 ppb) for Pima County. As a result, despite these monitored exceedances, Pima County has not violated the ozone standard, and still remains attainment for ozone. As an attainment area, major NSR permitting actions such as the RICE project are subject to PSD, rather than nonattainment NSR, regulations. As described in the response to Comment V above, the Air Quality Analysis for ozone was performed in accordance with EPA guidance for PSD permitting. In addition, we note that while the permit application may have only indicated Maricopa County as an ozone nonattainment area, the proposed TSD properly noted both Maricopa and Pinal County in the Air Quality Analysis for ozone.

W. Comment:
In selecting Background Design Values for TEP Project site, Applicant selected 2013-2015 ambient background design values. Applicant indicated that Design Values for the 2014-2016 period had yet to be posted on EPA's web site. 40 USC 52.21(m)(1)(v) mandates that monitoring data shall represent at least the year preceding receipt of the application. Data selected does not meet that criterion. This code provision authorizes the Administrator to determine appropriate data. The application should be amended for compliance with 40 USC 52.21(m)(1)(v).

Response:
We disagree with this comment. As noted by the commenter, the permit application indicated that 2013-15 ambient background design values were used because 2014-16 values were not available at the time of the original permit application. However, as indicated in Table 3-2 of the Air Quality Analysis contained in the Proposed TSD, we relied upon 2014-16 background concentrations in performing this analysis. [39]

X. Comment:
President Trump's decision to delay the federal government's determination of whether local areas are meeting the ozone standard of .070 ppm makes Pima County residents unnecessarily vulnerable to health threats and environmental harm resulting from unchecked ozone pollution. County and Federal Air Quality public servants owe Pima County the protection the Agency was created in order to oversee. In the current condition of the inability to know whether our County or parts of it should be declared in nonattainment of ozone standards, the federal, state and county authorities should use the precautionary principle until authorities at the federal level once again comply with their mandates.

Response:
The 2015 ozone NAAQS designation for Pima County is beyond the scope of the proposed permitting action

[39] https://www.epa.gov/air-trends/air-quality-design-values

open for public comment. However, we note that on June 4, 2018, EPA published a final rule establishing ozone NAAQS designations for multiple areas in the United States, including Pima County.[40] As seen in this final notice, Pima County was designated as attainment/unclassifiable for the 2015 primary and secondary ozone NAAQS.

Y. Comment:
The environmental justice argument lacks credible analysis. Did DEQ follow the guidance, find an increase in ambient O3 and just not share its level of significance or anticipated outcomes? Why does the assessment fail to report these? DEQ continues: "Pima County has determined from the modeling results for the Project that the Project would not cause or contribute to a violation of the applicable health based NAAQS for any of the pollutants regulated under the PSD permit. Furthermore, VOC emissions from the proposed Project will have an insignificant impact on ambient O3 concentrations." That there will be no adverse health impacts – at least on more sensitive populations – is simply not credible. That those impacts will not hit harder the communities in the vicinity of the plant is implausible. A statement of the relative impacts on frontline communities contrasted with more protected communities would have added a degree of credibility to the report.

Response:
Regarding the ambient impact of VOC emissions from the proposed project, we wish to clarify that the modeling results referenced by the commenter consist of the dispersion modeling performed for CO, PM_{10}, and PM2.5. As described in our response to Comment JB.U, site-specific photochemical modeling for ozone was not performed for the RICE project. Rather, we relied upon the Modeled Emission Rates for Precursors (MERPs), which represent a demonstration tool established in EPA guidance for the purpose of evaluating ozone impacts in PSD permitting. In the case of each of these pollutants, we relied upon either dispersion modeling (in the case of CO, PM_{10}, and PM2.5) or the use of the MERPs (in the case of VOC) to determine that emissions from the RICE project would not cause or contribute to a NAAQS violation. This approach is consistent with EPA practice in the context of an environmental justice analysis, in which "compliance with the NAAQS is an indicator that Agency action will not result in disproportionately high and adverse human health or environmental effects on minority and low-income populations residing near a proposed facility."[41]

IV. Comments Opposing/Supporting the Project

A. Comments Opposing the Project

1. #1-10 – Rudolf Lambrechtse

B. Comments Supporting the Project

1. #2-1 – Dr Richard Powell
2. #2-2 – Grace Gegenheimer
3. #2-3 – Bill Kelley

V. Public Comment Process

A summary of the public notification process can be found in Appendix A of this document along with public notices, press releases, social media posts by PDEQ, and mailing done to the community.

[40] 83 FR 25776, available online at https://www.gpo.gov/content/pkg/FR-2018-06-04/pdf/2018-11838.pdf

[41] *Pio Pico Energy Center*, PSD Appeal Nos. 12-04 through 12-06, 16 E.A.D. at 67 (EAB August 2, 2013)

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Please refer to our responses to Comment B.B.8 and 9 for more details.

S. Comment:
It is requested that PDEQ consider whether Saguaro Park Superintendent Darla Sidles comment that "The Clean Air Act is working and air quality is improving, but more needs to be done because air pollution impacts all our parks" be considered to activate 42 U.S.C. §7475, (d)(2)(B) and/or (e)(2)(C)(i), and if so, an evaluation of the adverse impact on the air quality related values (including visibility) should be considered.

Response:
The commenter requests that PDEQ consider whether the statement made by Saguaro Park Superintendent Darla Sidles, as published in an August 1, 2015 article on Tucson.com regarding visibility and regional haze at Saguaro National Park, is sufficient to be considered an indication that the RICE project will have an adverse impact on visibility. As discussed in our response to Comment B.B.12, PDEQ and TEP worked closely with the National Park Service in order to accurately characterize and model the site-specific visibility impact of the project on Saguaro National Park. In its February 8, 2016 letter response to PDEQ, NPS noted that the proposed project would result in an improvement in visibility relative to the existing Units 1 and 2 and did not have an objection to the draft permit based upon an adverse visibility impact.

T. Comment:
It is requested that PDEQ examine 40 CFR § 52.21(b)(3), 40 CFR § 70.4(b)(12), 40 C.F.R. §51.166(b)(1), 40 CFR. §52.21 (b)(3)(ii) and (b)(1) to verify compliance in light of the EPA guidance on illegitimate netting.

Response:
Based upon the regulations and guidance documents cited by the commenter, the NOx "illegitimate netting" asserted by the commenter refers to "project netting". Under 40 CFR 52.21(a)(2)(iv)(a), a project is a major modification for PSD if it causes both a significant emissions increase and a significant net emissions increase of a regulated NSR pollutant. Historically, this applicability determination is performed via a two-step process, in which Step 1 involves summing only the emission increases from the project in determining whether a significant emissions increase has occurred, followed by Step 2 in which both emission increases and decreases that are creditable and contemporaneous to the project are totaled to determine if a significant net emissions increase has occurred. Project netting is a practice that differs from this approach in that both project emission increases and decreases are considered in Step 1 of the process.

The RICE project did not make use of project netting, as only emission increases from the RICE project were considered in Step 1 when determining if a significant emission increase occurred. Because an increase of 170 tpy NOx from the RICE project exceeded the PSD SER, the analysis proceeded to Step 2, in which emission decreases associated with the shutdown of existing Units 1 and 2 were considered. The RICE project did not trip off PSD review for NOx until Step 2, which is consistent with the historical two-step process described above and not with the use of project netting.

Other commenters have raised different concerns regarding the NOx netting, such as whether the Unit 1 and 2 emission decreases are contemporaneous and creditable. These concerns have been addressed separately in our response to Comment B.B.2.

U. Comment:
Ozone pollution levels in Pima County have been hovering just below or right at NAAQS nonattainment. DEQ sent out 62 ozone advisories in 2015, compared to two in 2006. Actions that would threaten to push ozone levels even higher than they already are pose a direct threat to the public health and well-being and to the integrity of the uniquely beautiful surrounding region. TEP failed to consider relevant site-specific conditions in its use of "Modeled Emission Rates for Precursors (MERPs)". Among local conditions that aggravate ozone creation and are not reflected by the MERP modeling applied by the applicant are the following:

1. The Sundt Generation Station is located just north of I-10. Vehicle traffic forms ozone pollution through VOC and NOx emissions. TEP has not demonstrated that vehicle emissions on I-10 combined

with ozone precursor emissions from plant activities are unlikely to cause ozone NAAQS exceedances.

2. Tucson has a higher proportion of non-native trees than most urban settings, and many of them contribute more than has recently been suspected to biogenic ozone formation. TEP has not demonstrated that ozone formation aggravated by this unusual urban feature does not increase the likelihood that plant emissions will cause NAAQS exceedances with unjustifiable hazardous health consequences.

TEP has failed to demonstrate that the proposed facility would not cause or contribute to air pollution in excess of maximum allowable ozone NAAQS concentrations.

Response:
Ground-level ozone is a pollutant that is generally not directly emitted into the atmosphere, but instead predominantly formed as a secondary pollutant from precursor emissions of other pollutants, such as NOx and VOC, that are directly emitted into the atmosphere and subsequently form ozone through complex photochemical reactions. There are multiple source categories of anthropogenic NOx and VOC in Pima County, including an inventory of large industrial point sources, smaller area sources, as well as mobile sources. Ambient ozone concentrations can be affected by emission increases and decreases in these categories through factors such as population growth and economic development, and the Department examines changes in the emissions of these various categories in its planning efforts to ensure continued attainment of the NAAQS.

By contrast, when evaluating the ozone impact of a single source or project in the context of a permitting action, the EPA has recommended a two-tiered approach for PSD permitting actions.[7] As described in the Air Impact Analysis contained in the Proposed TSD, the first tier involves the use of appropriate and technical credible relationships between emission and ambient impacts developed from existing modeling studies that are sufficient for evaluating a project source's impacts. The second tier involves more sophisticated case-specific application of chemical transport modeling. In recommending this two-tiered approach, the EPA also provided draft guidance on the development and use of Modeled Emission Rates for Precursors (MERPs). MERPs are a type of Tier 1 demonstration tool that may be used to describe an emission rate of a precursor that may result in an increase in ambient ozone relative to the 8-hour ozone NAAQS. In its draft guidance, the EPA performed extensive regional photochemical modeling of hypothetical sources in multiple geographic areas for purposes of illustrating the development and use of MERPs, based on a screening threshold for 8-hour ozone of 1 ppb. The EPA included the MERPs for multiple geographic areas in its guidance, and also indicated that permit applicants and permitting authorities have the discretion to perform their own regional photochemical modeling and develop their own MERP values.

As noted in Attachment B (Air Impact Analysis) to Appendix C of the Proposed TSD, we relied upon the illustrative MERPs contained in the draft EPA guidance to evaluate project impacts, and did not perform photochemical modeling to develop an additional set of MERP values. The Proposed TSD indicates that the lowest VOC MERP for 8-hour ozone in the western United States is 1,049 tpy. The VOC PTE of the RICE project is 215 tpy, which is well below this value. The commenter notes that the MERPs listed in the draft EPA guidance do not account for certain local conditions present in Tucson and near the Sundt Generating Station site, specifically vehicle traffic from I-10, and the higher proportion of non-native trees. We acknowledge that the local conditions noted by the commenter are not reflected in the development of the 1,049 tpy VOC MERP, but note that the effect of such local considerations would be reflected in background ozone concentrations as measured by ambient monitors. In addition, we note that the draft EPA guidance included a source model simulation for VOC emissions for Gila County, AZ, which is located in south central Arizona and exhibits arid conditions that provide a more direct comparison to Pima County. This source model simulation indicates that an increase of 500 tpy VOC from a hypothetical source corresponds to a 0.82 parts per billion increase in ambient ozone.[8] The VOC PTE of the RICE project is 215 tpy, which is less than the 500 tpy source model simulation. As a result, we consider the MERPs contained in the draft EPA guidance to provide a sufficiently

[7] Wayland, Richard, "Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program", December 2, 2016. Available online at https://www3.epa.gov/ttn/scram/guidance/guide/EPA454_R_16_006.pdf.

[8] Ibid, Table A-1

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renewable resources by 2030. The RICE units were selected by TEP because of their ability to address the variability and intermittency of renewable resources. The location or region into which the power generated by the proposed project will be supplied has not been identified in the permit application documentation. PDEQ and EPA do not have the authority to disallow the project based on the market that will be supplied by the proposed project. Imposing a restriction on TEP to only provide power to a specific market may fundamentally redefine the project. PDEQ and EPA do not have the authority to require TEP to fundamentally change the nature of the project.

L. Comment:
RICE units are efficient at small sizes but not at the large size proposed by TEP.

Response:
TEP has proposed to install RICE units because of their ability to address the variability and intermittency of renewable resources. The RICE units were selected because they provide flexible, fast-responding power to address power fluctuations associated with renewable resources.[36] Because renewable resources produce power intermittently, TEP requires back up generation capability with fast start times and the ability to ramping to full load quickly, the ability to operate over a wide range of loads without compromising efficiency, and reduced Operation and Maintenance (O&M) resulting from repeated unit cycling. According to TEP's 2017 IRP, TEP conducted a Flexible Generation Technology Assessment which found that the RICE technology is the preferred technology to provide capacity and assist in mitigating renewable energy intermittency and variability.[37] Therefore, requiring TEP to select a different technology would fundamentally change the proposed project. PDEQ and EPA does not have the authority to fundamentally change the nature of the project.

M. Comment:
TEP needs to follow state and local regulations.

Response:
The proposed project is required to meet EPA and PDEQ requirements. The proposed project has been reviewed by PDEQ and EPA and has been deemed to meet all applicable requirements

N. Comment:
Ozone levels will be affected by the increase in ozone precursors and Tucson is at the edge of ozone nonattainment.

Response:
The Prevention of Significant Deterioration (PSD) permitting program is designed to assure that new and modified industrial facilities do not cause adverse impacts on air quality. The proposed project is located in an attainment area for ozone. The proposed project must be evaluated to determine if the modification is "major" based on whether the modification results in an increase in emissions above specified emission rates which define whether the increase in emissions is "significant" or *de minimis*. Ozone levels are attributable to NOx and VOC emissions. Therefore, an assessment of the emissions increase from the proposed project is required. The NOx and VOC net emissions increases from the proposed project are both less than the significant emission rate (40 tons per year). Emission increases that are less than the significant emission rate are considered *de minimis* (not "major") and do not require a PSD review and an air impact analysis is not required.

O. Comment:
TEP should consider the use of internal combustion engines that combust hydrogen instead of natural gas.

[36] Information obtained from the TEP 2017 IRP at: http://www.tep.com/wp-content/uploads/2017/04/TEP-2017-Integrated-Resource.pdf.
[37] Information obtained from the footnote on page 22 of the TEP 2017 IRP located at: http://www.tep.com/wp-content/uploads/2017/04/TEP-2017-Integrated-Resource.pdf.

Response:
TEP has proposed to install RICE units that combust natural gas because of their ability to address the variability and intermittency of renewable resources. The RICE units were selected because they provide flexible, fast-responding power to address power fluctuations associated with renewable resources.[36] Because renewable resources produce power intermittently, TEP requires back up generation capability with fast start times and the ability to ramping to full load quickly, the ability to operate over a wide range of loads without compromising efficiency, and reduced Operation and Maintenance (O&M) resulting from repeated unit cycling. It is unclear whether RICE units that combust hydrogen are readily available, and requiring the facility to use an engine that uses a different type of fuel (hydrogen in this case) could fundamentally change the proposed project. Under the PSD program, PDEQ and EPA do not have the authority to fundamentally change the project.

P. Comment:
Allowing TEP to do this impacts our water – proposed change will increase water usage.

Response:
The air permit process does not include an evaluation of the proposed water usage. Water usage is not regulated under the PDEQ air regulations that govern the issuance of the air permit. Therefore, water usage is not considered as part of the air permitting process.

Q. Comment:
The annual NOx emission limit poses a severe operational restriction that would place unusual limitations on allowed capacity factors in order the RICE to remain compliant with the NOx emission limit. Attached calculations indicate that the NOx emission limit would only provide for 144.5 hrs/yr of full power-peaking, which results in a very low capacity factor that is inconsistent with the project's state goal of meeting daily mismatch between (a) distributed and utility solar production and (b) electrical power demand patterns.

Response:
The NOx calculations provided by the commenter are based upon an uncontrolled NOx emission rate of 59.1 lb/hr per engine. As discussed in a response to a similar comment (See Comment II.B.5), these calculations do not account for the effect of the SCR system for NOx control required by Condition II.A.1.e of the Proposed Permit. The controlled NOx emission rate, based upon use of the SCR system, is 1.5 lb/hr per engine during normal operations.[38] As a result, the required use of the SCR system will allow the RICE units to operate at sufficient capacity factors (i.e., more hours of operation) while still complying with the NOx annual emission limit.

R. Comment:
In light of the point raised in Comment Q above, there is concern that the severe operational restriction on operating time of the RICE may result in ways to operate outside of the parameters in the proposed permit. It is requested that compliance verification measures be established and agreed upon between PDEQ and TEP to assure compliance with the NOx emission limits.

Response:
As noted in the response to Comment Q above, the Proposed Permit requires the use of SCR on the RICE units for NOx control, which will allow the units to operate within the annual NOx limit at higher capacity factors than indicated by the commenter. As a result, we disagree that the annual NOx limit will result in severe operational restrictions on the engines. For compliance verification purposes, the Proposed Permit requires multiple requirements for source testing, monitoring of the SCR system, and reporting and recordkeeping.

[36] Information obtained from the TEP 2017 IRP at: http://www.tep.com/wp-content/uploads/2017/04/TEP-2017-Integrated-Resource.pdf.
[38] Project emission estimates can be found in Attachment A to Appendix C of the Proposed TSD (page 155 of 729 in the Adobe Acrobat version of the Proposed TSD).

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that the RICE technology is the preferred technology to provide capacity and assist in mitigating renewable energy intermittency and variability.[21]

Not installing the RICE units would fundamentally redefine the source, and therefore, this is not considered as part of the control technology analysis. The proposed change (and resulting emission increase) has been demonstrated to meet the control technology requirement and therefore, the increase in emissions is permissible.

F. Comment:
Several commenters made statements to indicate their disappointment to PDEQ's determination that projected emissions of pollutants from the Project will not result in disproportionately high and adverse human health or environmental effects on any population, including minority populations and low-income populations. The Sierra Club requested the environmental justice impacts should include air quality modelling of the nitrogen oxides (NO_X) impacts and that the agencies EJ report wrongly relies on the applicants erroneous "netting" of pollutants that does not comply with the law and does not reflect the reality of the toxic air pollution that people in the community will breathe. Furthermore, the Sierra Club suggested that the EJ analysis should consider the total amount of air pollution that the facility will emit and not subtract the emissions from the shutdown of the 2 existing gas units.

Response:
PDEQ is committed to addressing environmental justice concerns in the TEP RICE project. PDEQ has reviewed the EJ analysis in accordance with the Executive Order 12898, entitled "Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations." For purposes of Executive Order 12898, EPA and PDEQ recognize that, in the context of an environmental justice analysis, compliance with the applicable NAAQS is generally emblematic of achieving a level of public health protection that demonstrates that PDEQ's issuance of the permit for the proposed facility will not have disproportionately high and adverse human health or environmental effects on minority populations and low-income populations due to exposure to the relevant criteria pollutants. This is because NAAQS are health-based standards, designed to protect human health with an adequate margin of safety, including sensitive populations such as children, the elderly, and asthmatics.

PDEQ has considered in detail environmental justice issues associated with this PSD permit decision, and offered the public the opportunity to comment on such issues as part of the notice and comment process. PSD requirements do not necessitate an analysis for criteria pollutants that do not trigger PSD review. The project emissions of NO_X were calculated as the emissions from the proposed ten RICE units minus the emissions from the natural gas-fired units to be retired (No. 1 and No. 2). The resulting NO_X emissions are below the NO_X significant emission rate of 40 tons per year (TPY). Therefore, the NO_X emissions do not trigger New Source Review under PSD regulations and air dispersion modeling was not required to be performed for NO_X. Note the total amount of air pollution that the facility will emit is calculated with the operation of the ten RICE units. Units 1 and 2 will be shutdown upon the start up of the first RICE unit. The air quality and environmental justice analysis conducted by PDEQ shows that he project meets all applicable requirements and is protective for human health and the environment. Both units 1 and 2 will be shutdown prior to startup of RICE.

G. Comment:
Carbon reduction and Carbon sequestration should be considered; RICE is not the best technology.

Response:
An evaluation of the carbon capture and sequestration (CCS) was conducted within the BACT analysis. CCS has not been effectively demonstrated or made commercially available for RICE units. According to the preamble for the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, CCS has been demonstrated as technically feasible for steady-state (i.e., base load) operations but has not been demonstrated for operations such as

[21] Information obtained from the footnote on page 22 of the TEP 2017 IRP located at: http://www.tep.com/wp-content/uploads/2017/04/TEP_2017-Integrated-Resource.pdf

intermediate load natural gas combined cycle (NGCC) power plants which start and stop frequently. Although the preamble specifically discusses NGCC plants, the same concept applies to the proposed RICE units which are designed to start and stop frequently and to operate at varying loads. A review of power plant PSD permits for similar natural gas RICE unit applications indicates that CCS has not been found to be technically feasible for other RICE installations.[22] Therefore, CCS was identified as technically infeasible.

H. Comment:
Allowing TEP to do this impacts public health and will make the air quality worse in Tucson.

Response:
The Clean Air Act requires EPA to set National Ambient Air Quality Standards (NAAQS) for pollutants that are considered harmful to public health and the environment. There are two national air quality standards:

- primary standards, which are designed to protect public health; and
- secondary standards, which are designed to protect the public welfare from adverse effects, including those related to effects on soils, water, crops, vegetation, man-made materials, animals, wildlife, weather, visibility, and climate; damage to property; transportation hazards, economic values, and personal comfort and well-being.

The project triggers PSD review for carbon monoxide (CO) and particulate matter (PM) with an aerodynamic diameter less than or equal to 10 microns (PM_{10}) and PM with an aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$). As a result, an air impact analysis is required to evaluate the project impacts with regard to the NAAQS, as well as PSD Class II increments, and PSD Class I increments at the eastern and western units of Saguaro National Park (SNP) and Galiuro Wilderness Area (GWA). The air impact analysis was conducted for the proposed project and demonstrates that the Project does not cause or contribute to an exceedance of any NAAQS or PSD increment for these pollutants.

I. Comment:
TEP states that they are not subject to New Source Climate Change standards codified at 40 CFR 60 Subpart TTTT because the units are small but they should consider the units in total.

Response:
TEP stated that the RICE are not an affected facility under Subpart TTTT because it is not an "electric generating unit", "integrated gasification combined cycle facility," "stationary combustion turbine," or "steam generating unit," by definition in Subpart TTTT. The following definitions are in 40 CFR Subpart TTTT 60.5580

J. Comment:
The Sierra Club and TEP are saying different things.

Response:
The TEP and Sierra Club statements that the commenter is referring to are not specifically identified. PDEQ cannot comment on statements or information provided by Sierra Club and TEP. To prepare the proposed permit, PDEQ and EPA evaluated the information provided in the permit application and prepared the emission calculations, a control technology review, the air quality impact analyses, etc. This information formed the basis of the proposed permit and technical support documentation.

K. Comment:
TEP is doing this expansion to provide power to Phoenix. TEP already has an overcapacity, so the proposed change is unnecessary. TEP will send the power generated by the project elsewhere and the pollution will stay here.

Response:
TEP has proposed this project to meet a corporate goal to supply at least 30 percent of retail energy load from

[22] BACT reviews conducted for PSD permits for proposed RICE units at power plants (see Attachment 1 of Appendix C – BACT Analysis of the Permit Technical Support Document).

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circulations in the county where the source will be located. PDEQ provided notification of receipt of the permit application in the Arizona Daily Star on October 2, 2017.

In addition, PDEQ is required to provide public notice, an opportunity for public comment, and an opportunity for a hearing before taking final action on a significant permit revision. This requires publication of a notice once each week for two consecutive weeks in two newspapers of general circulation in the county where the source will be located. PDEQ is also required to mail a copy of the notice to persons who have requested in writing to be placed on the mailing list for notifications. The proposed permit modification was publicized in two newspapers, in four news releases to 144 media sources and elected officials, and in two news releases emailed to 751 air quality advisory/information recipients. The news release was mailed to neighborhood association representatives for the following neighborhoods: Elvira, Mortimore, Pueblo Gardens, South Park, Western Hills II, and Sunnyside. The news release was also sent to: U.S. EPA, City of Tucson, City of South Tucson, Town of Marana, Town of Oro Valley, Green Valley Council, Pasqua Yaqui Nation, Pinal County, Santa Cruz County, National Park Service, National Forest Service, U.S. Air National Guard, Tucson Electric Power, Sierra Club, U.S. Fish and Wildlife, San Xavier District Tohono O'Odham Nation, Vail Chamber of Commerce, Pima Association of Governments, and Davis-Monthan Air Force Base. An article on the proposed project was published in the Pima County Community-wide Newsletter (4,200 subscribers) on February 9, 2018.

A public open house (informational meeting) and two public hearings were held to provide information and receive comment on the proposed permit revision. The open house was held on February 15, 2018 at the Abrams Public Health Center, located at 3950 S. Country Club Road Tucson, Arizona. The public hearings were held on March 1, 2018 at Abrams Public Health Center and March 28, 2018 at the Pima County Public Works Building (located at 130 W. Congress Street, Tucson, Arizona). Invitations to the open house and the public hearing scheduled for March 1, 2018 were mailed to 9,558 residents and businesses located near the TEP facility on February 5, 2018.

Information regarding the open house and the public hearings was published on the Pima County DEQ website and the Pima County Main website. PDEQ tweeted information about the public meetings on February 5th and 15th, and March 15th and posted information on the Pima County Facebook page on February 8, 2018. Additional details regarding the public outreach and notifications is included in Attachment 1.

E. Comment:
The proposed project will increase greenhouse gas (GHG) and carbon dioxide (CO_2) emissions. These emissions contribute to climate change and should not be allowed.

Response:
The Clean Air Act, Arizona Revised Statutes, and Pima County Code allow emission increases including GHG and CO_2 provided that best available control technology (BACT) is installed to control emissions. For existing sources that trigger Prevention of Significant Deterioration (PSD) review, best available control technology (BACT) applies to each proposed emissions unit at which a net emissions increase would result from the change[22]. The proposed project will cause a net emission increase in GHGs, specifically carbon dioxide (CO_2, methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6). Therefore, the GHG control technology review applies to the proposed emission units and associated pollutants as follows:

- RICE units – GHG (CO_2, N_2O, CH_4)
- Natural gas piping – GHG (CH_4)
- High voltage circuit breakers – SF_6

[22] 40 CFR §52.21(j)(3)

The control technology review was conducted based on EPA guidance including the *New Source Review Workshop Manual*[23] *(NSR Workshop Manual)* and the *PSD and Title V Permitting Guidance for Greenhouse Gases*[24] *(GHG Permitting Guidance)*. Both of these documents provide general guidance for determining the scope of the best available control technology (BACT) analysis. The GHG Permitting Guidance recommends that BACT analyses for GHG emissions be conducted in the same manner as for other regulated pollutants[25]. A top-down procedure is used to determine BACT for an emission unit. Before initiating the BACT analysis for a given emission unit and a given pollutant, PDEQ identified the minimum acceptable level of control allowed under an applicable requirement (i.e. New Source Performance Standard (NSPS) or National Emission Standard for Hazardous Air Pollutants (NESHAP)). This minimum acceptable level of control is commonly called the BACT "baseline". Next, the five-step "top-down" approach was used to assess BACT. The five steps of a top-down BACT analysis are:

Step 1: Identify all available control technologies with practical potential for application to the emission unit and regulated pollutant under evaluation;
Step 2: Eliminate all technically infeasible control technologies;
Step 3: Rank remaining control technologies by effectiveness and tabulate a control hierarchy;
Step 4: Evaluate most effective controls and document results; and
Step 5: Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

The first step is to identify all control technologies with potential application to the emission unit and pollutant subject to review.[26] According to EPA guidance, the review shall include the following types of control technologies:

- Inherently lower-emitting processes and practices
- Add-on controls, and
- Combinations of inherently lower-emitting processes and add-on controls

EPA's GHG Permitting Guidance[27] states that a BACT analysis for GHG should not redefine the source's purpose and that the proposed design should be assessed to determine which design components are inherent for the proposed purpose and which may be changed for pollution reduction purposes without disrupting the applicant's basic purpose. It further states that BACT should not be applied to regulate the applicant's purpose or objective for the proposed facility. The guidance also notes that a decision to exclude an option because it would fundamentally redefine the source must be explained and documented in the permit record.[28] The fundamental business purpose of the proposed project is to allow TEP to provide reliable, efficient, grid-balancing resources which can ramp up quickly and provide 100% of the effective load carrying capacity (ELCC) during peak periods of any length. TEP selected RICE units because they provide flexible, fast-responding power and assist in mitigating power fluctuations associated with renewable resources.[29] Because renewable resources produce power intermittently, TEP requires back up generation capability with fast start times and the ability to ramping to full load quickly, the ability to operate over a wide range of loads without compromising efficiency, and reduced Operation and Maintenance (O&M) resulting from repeated unit cycling. According to TEP's 2017 IRP,[30] TEP conducted a Flexible Generation Technology Assessment which found

[23] Office of Air Quality Planning & Standards, US EPA, *New Source Review Workshop Manual*, October 1990. *(NSR Workshop Manual)*.
[24] Office of Air Quality Planning & Standards, US EPA, Document Number EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases*, dated March 2011.
[25] *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA-457/B-11-001, March 2011
[26] *NSR Workshop Manual*, (Section IV).
[27] *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA-457/B-11-001, March 2011.
[28] *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA-457/B-11-001, March 2011.
[29] Information obtained from the TEP 2017 IRP at: http://www.tep.com/wp-content/uploads/2017/04/TEP-2017-Integrated-Resource.pdf.
[30] TEP 2017 IRP at: http://www.tep.com/wp-content/uploads/2017/04/TEP-2017-Integrated-Resource.pdf.

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greater than the 10 tons/year SER for this pollutant and NOx and or SO_2 emission rates are less than the respective 40 tons/year SER for these pollutants. For Case 3, EPA guidance recommends an analysis to address secondary $PM_{2.5}$ impacts. The Proposed Permit and Proposed TSD should be revised to include such an analysis.

Response:
We disagree with the commenter's assertion that the dispersion modeling should include modeling of secondary PM2.5 emissions. EPA's $PM_{2.5}$ Modeling Guidance[18] provides recommendations regarding technical approaches for conducting $PM_{2.5}$ NAAQS and PSD increment compliance demonstrations. This includes how to adequately account for contributions from primary $PM_{2.5}$ concentrations from a proposed new or modifying source's direct PM2.5 emissions and from secondarily formed PM2.5 concentrations resulting from the source's PM2.5 precursor emissions. This guidance discusses several assessment cases[19], and provides recommendations regarding when secondary impacts of NOx and SO_2, as $PM_{2.5}$ precursor emissions, should be assessed. The dispersion modeling approach described in the proposed permit and TSD corresponds to Case 2, which does not recommend modeling of precursor emissions, while the commenter asserts that the Case 3 applies, which does recommend modeling of precursor emissions. Specifically, the commenter asserts that, due to deficiencies in the NOx netting analysis (see Comments 2-4), Case 3 applies because the RICE project has a NOx emission increase greater than the 40 tpy PSD SER for NOx. As noted in our responses to Comments II.B.2 through 4, we have updated certain permit conditions in the final permit to ensure that the emission reductions from the shutdown of Units 11 and 12 are creditable. The net emission increase of NOx for the RICE project is 30 tpy, which is below the PSD SER for NOx of 40 tpy. As a result, PSD review for NOx is not triggered as a direct pollutant for SO_2, nor as a precursor for $PM_{2.5}$. Thus, Case 2 of the modeling guidance applies.

b. Comment:
As discussed in Comments 2-4, the commenter asserts that the RICE project triggers PSD review for NOx, which requires dispersion modeling for demonstrating compliance with the short-term and annual NAAQS for NO_2. The Proposed TSD must be revised to include such an analysis.

Response:
As discussed in our responses to Comments II.B.2-4, we have made several updates to the final permit to reflect our intent of ensuring that the net increase of NOx from the RICE project does not exceed the 40 tpy PSD SER for NOx. Thus, PSD review for NOx is not triggered, and a Class II dispersion modeling analysis for NOx is not required.

17. Comment:
The commenter lists certain typographical and other errors in the TSD.

Response:
We acknowledge these errors and typos, and have corrected them in the final permit.

[18] Page, Stephen, U.S. EPA, "Guidance for PM2.5 Permit Modeling", May 20, 2014. Available online at: https://www3.epa.gov/scram001/guidance/guide/GuidAnce_for_PM25_Permit_Modeling.pdf
[19] Ibid, Table 8-1

III. Comments from the Public That Do Not Reference Specific Permit Conditions

A. Comment:
Solar and wind power with battery backup should be used instead of RICE.
a. Renewable target of 30% by 2030
b. Study comparing cost impact of NG versus solar + batteries
c. Costs of batteries should not be a reason not to employ them
d. Technology improvements have made batteries viable

Response:
TEP selected RICE units to address a specific business purpose. TEP has set a goal to supply at least 30 percent of retail energy load from renewable resources by 2030. In order to meet this goal, TEP must address the operational challenges that are associated with the intermittency and variability of energy generated by renewable resources. The RICE units were selected by TEP because of their ability to ramp up quickly to provide load carrying capacity to provide reliable, grid-balancing resources to address the variability and intermittency of renewable resources. The details of TEP's goals and the selection of RICE for this project are included in the TEP 2017 Integrated Resource Plan (IRP)[20].

TEP did not propose to install renewable power generation technology, energy storage, or other power production technologies at RES. Implementation of any of these options would fundamentally redefine the project. PDEQ does not have the authority to require TEP to fundamentally change the nature of the project.

B. Comment:
The increase in pollutant emissions (PM, NOx, VOC, and HAPs) should not be allowed.

Response:
The Clean Air Act, Arizona Revised Statutes, and Pima County Code allow emission increases provided the increases do not cause a violation of the National Ambient Air Quality Standards and that best available control technology is installed to control emissions. TEP has demonstrated the proposed project meet federal, state, and county requirements.

C. Comment:
TEP should invest in demand management.

Response:
TEP has proposed to install the selected RICE units to address a specific business purpose. As noted previously, TEP is proposing to install the RICE units to address the operational challenges associated with the intermittency and variability of energy generated by renewable resources. The RICE units were selected because of their ability to quickly provide load carrying capacity to address the variability and intermittency of renewable resources. The scope of the proposed project does not include demand management. PDEQ does not have the authority to fundamentally change the nature of a proposed project. Therefore, PDEQ does not have the authority to require TEP to invest in demand management, as this would fundamentally change the nature of the proposed project.

D. Comment:
The proposed permit changes were not sufficiently publicized.

Response:
PCC 17.12.180 provides the requirements for public participation for Class I permits. The public participation requirements were met for the TEP permit. PDEQ is required to provide public notice of receipt of complete applications for major modifications to major sources by publishing a notice in a newspaper of general

[20] Information obtained from the TEP 2017 IRP at: http://www.tep.com/wp-content/uploads/2016/04/TEP-2017-Integrated-Resource.pdf.

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potential to emit in the Proposed TSD of 59.1 lbs hour NOx for one RICE unit, i.e., 590.1 lbs/hour NOx combined for all ten RICE units.

Thus, the results of the PLUVUE II modeling are not supported and the Proposed Permit does not ensure compliance with the modeled impacts. (In contrast, to ensure compliance with the air quality dispersion modeling analysis for PM10 and PM2.5, which determines compliance with the respective short-term (24-hour) NAAQS for these pollutants, the Proposed TSD requires, and the Proposed Permit incorporates, the modeled emission rate as a permit condition. The Proposed Permit must be revised to include a permit condition limiting short term emission rates to the modeled emission rates described above. Alternatively, the PLUVUE II modelling must be rerun with the potential to emit for all 10 RICE units of 591.0 lbs/hour of NOx.

Response:
We disagree with the commenter's assertions that the PLUVUE II visibility modeling underestimates visibility impacts, and that the Proposed Permit lacks conditions limiting short-term NOx emission rates to the modeled emission rates. The commenter asserts that visibility impacts are underestimated because the visibility modeling was not performed using the NOx emission rate of 59.1 lb/hr per engine, which corresponds to the NSPS subpart JJJJ emission standard of 1.8 g/hp-hr established in Condition II.A.1. Instead, as noted by the commenter, and as described in the Proposed TSD, the visibility modeling used the NOx emission rates based upon vendor specifications for periods of startup and normal operations. Specifically, . . the two model cases that were evaluated used the worst-case NOx emission rates that could occur based upon a combination of emissions from startup operations and normal operation at vendor specified emission rates consistent with the use of SCR."[18] We consider the use of these controlled emission rates appropriate, and disagree that the Proposed Permit lacks conditions that limit short-term NOx emissions to these rates. The proposed permit includes a requirement for each engine to operate with an SCR system (Condition II.A.1.c), as well as requirements for monitoring of SCR operating parameters (Condition II.B.2) and work practice standards to ensure proper operation of the SCR in a manner consistent with manufacturer recommendations (Conditions II.A.1.c.i through iv). In addition, Condition II.A.6 of the Proposed Permit limits total startups per calendar day for each engine to 5 startups, which is consistent with the modeling cases. These permit conditions restrict the NOx emission rate of each engine to the model emission rates. As a result, we do not consider revised visibility modeling at uncontrolled NOx emission rates to be warranted, and do not consider the modeled visibility impacts to be underestimated.

14. Comment:
The commenter asserts that the modeling analysis for CO, PM10 and PM2.5 is not supported, as follows: The Proposed TSD determines compliance with short-term NAAQS for CO, PM10 and PM2.5 based on "average emission rates." These average emission rates are summarized in Tables 3-5 and 3-6 of Attachment B to Appendix C of the Proposed TSD. PDEQ modeled the 1-hour and 8-hour CO concentrations based on the startup emissions rate for this pollutant of 18.2 lbs/hour provided by the vendor. PDEQ modeled the 24-hour PM10 and PM2.5 concentrations based on 24-hour average emissions rates calculated based on 21.5 hours of operation at the vendor-supplied emissions rate including a buffer of five startups per day. As discussed in a previous comment, the vendor supplied emissions rates are not guaranteed and are not required as enforceable permit conditions. Thus, the results of PDEQ's Class II significant impact modeling analysis is not supported. Instead, modeling must be based on the maximum emission rates incorporated into an enforceable permit condition.

Response:
We disagree with the commenter's assertion that the modeling for CO, PM10, and PM2.5 is unsupported. The commenter is asserting that average, rather than maximum, emission rates were

[18] We note that the commenter has raised concerns regarding the vendor information justifying the NOx emission rates during startup and SCR operation. We have addressed these issues separately in our response to Comment II.B.9

used as modeled emission rates. We wish to clarify that the term "average emission rate", as it appears in Table 3-5 of Attachment B (Air Impact Analysis) to Appendix C of the Proposed TSD, is used in column headings to summarize model emissions rates for various pollutant-specific averaging periods (e.g., "CO 1-hour average emission rate"). These column headings are not intended to represent "average" emission rate occurring over that period, but rather the emission rate for a particular "averaging period". As described in Section 3.3 of the Air Impact Analysis, the emission rates in Table 3-5 are the maximum emission rates that occur over the corresponding averaging period, consistent with operational limitations established by the proposed permit. In addition, we note that because startup emission rates are either equal to or greater than emissions during normal operations, startup emission rates were accounted for in determining maximum modeled emission rates, as discussed in further detail below.

For example, the commenter notes that the modeled 1-hr CO emission rate is 18.20 lb/hr, which represents the maximum CO emission rate over a 1-hr averaging period. As noted in Table 3-5 of the Air Impact Analysis, the CO startup emission rate is 9.1 lb/30 min, which is higher than the CO emissions rate of 2.64 lb/hr during normal operations. Since Condition II.A.5 of the proposed permit limits engines startups to no more 30 minutes in duration, the worst-case CO emissions scenario over a 1-hour period represents two 30-minute startup events in a single hour, or 18.20 lb/hr

Similarly, the modeled PM10 emission rate of 2.50 lb/hr represents the maximum PM_{10} emission rate over a 24-hr averaging period. As noted in Table 3-5 of the Air Impact Analysis, the PM_{10} startup emission rate is 1.8 lb/30 min (equivalent to 3.6 lb/hr), which is higher than the PM_{10} emission rate of 2.37 lb/hr during normal operations. Since Condition II.A.6 of the proposed permit limits the total number of startups for each RICE in a single calendar day to no more than 5, the worst case PM_{10} emission scenario over a 24-hour period represents five 30 minute startup events in a single day, combined with the remaining 21.5 hours of the day at normal operation. This calculation is described in detail in footnote 2 in Table 3-5 of the Air Impact Analysis.

As a result, the maximum modeled emission rate for a particular averaging period consists of a combination of emissions rates corresponding to varying periods of startup and normal operation. We disagree with the commenter's assertion that these emissions rates are unsupported or unenforceable. The BACT limits established in the proposed permit represent short term emission limits that are consistent with the modeled emission rates. As discussed in greater detail in our response to Comment II.B.8, the proposed permit requires sufficient monitoring, recordkeeping and reporting requirements to determine compliance with these BACT limits. With regard to the vendor supplied emissions rates for periods of startup, please refer to our response to Comment II.B.9, in which we discuss the documentation and support for the vendor supplied startup emission rates.

15. Comment:
The commenter asserts that the proposed TSD fails to address the requirement for modeling of secondary PM2.5 emissions, as follows.

Modeling of secondary $PM_{2.5}$ emissions is required based on EPA guidance, and PDEQ must model the secondary $PM_{2.5}$ emissions to properly demonstrate compliance with the $PM_{2.5}$ NAAQS. Specifically, the Applicant discusses the May 20, 2014 guidance from EPA regarding $PM_{2.5}$ modeling for permitting purposes, which defines four cases for what type of air quality modeling analysis is needed for consideration of direct and secondary $PM_{2.5}$ emissions.

The Applicant finds that $PM_{2.5}$ modeling for the RICE project falls into Case 2, i.e., direct $PM_{2.5}$ emissions are equal to or greater than the 10 tons/year significant emission rate ("SER") for this pollutant and NOx and/or SO_2 emission rates are less than the respective 40 tons/year SER for these pollutants, thus, concludes that an analysis to address secondary $PM_{2.5}$ impacts is not required

However, as demonstrated in Comment IV, the RICE project in the Proposed Permit would exceed the 40 tons/year SER for NOx emissions, thus, Case 3 applies, i.e., direct $PM_{2.5}$ emissions are equal to or

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11. Comment:

The commenter asserts that permit conditions are inadequate to ensure compliance with SO_2 emission limits for the RICE units, as follows:

Based on a sulfur content in pipeline natural gas of 7,500 grains per million cubic feet, the 12-17 Revised Application determines the potential to emit of SO_2 and sulfuric acid mist ("SAM") as sulfur trioxide SO_3 for each of the RICE units at 0.32 lbs/hour and 1.4 tons/year SO_2 and 0.050 lbs/hour and 0.22 tons/year SO_3, respectively. The Proposed TSD provides the respective potential to emit for SO_2 and SAM in Attachment A to Appendix C, Table A-1, but the Proposed Permit contains no corresponding emission limits for either SO_2 or SO_3 or the sulfur content in natural gas. The only related permit condition is contained in Condition B.1., Fuel Sulfur Limitations:

Except as otherwise specified in the Specific Conditions of this permit, the Permittee shall be considered in compliance with the fuel sulfur limitations in this permit by demonstrating that only the specified fuel allowed was fired in the applicable equipment. Such a demonstration may be made by making available to the Control Officer for his inspection, documentation, such as invoices or statements from the fuel supplier, or sample analysis which verify the sulfur content of the fuel being piped and/or delivered. [PCC 17.12.180 A.3.c] [Locally Enforceable Condition]

This condition is inadequate to ensure that fuel sulfur content in natural gas is below the 7,500 grains per million cubic feet assumed for the Applicant's emission calculations upon which PDEQ relies for its potential to emit presented in summary table "IGS Facility Wide Potential to Emit . . . Summary." Instead, the Proposed Permit should be revised to contain a condition specifying the maximum sulfur content in the pipeline natural gas is 7,500 grains per million cubic feet (0.75 grains/100 scf) or less demonstrated by TEP maintaining a copy of the tariff agreement approved by the Federal Energy Regulatory Commission with the same specification or less. Absent such a requirement, the visibility impact analysis for the RICE project is not supported.

Response:

The permit has been revised to address this comment. Permit Condition B.A.11 in Part B has been added to the permit specifying the maximum sulfur content in the pipeline quality natural gas and requiring the Permittee to maintain documentation from the fuel supplier demonstrating compliance with the sulfur content limitation.

12. Comment:

The commenter asserts that visibility modeling results indicate that the RICE project has an adverse visibility impact at Saguaro National Park, as follows:

Pursuant to 40 CFR §52.21(o) and PCC § 17.16.630, the Proposed TSD, Appendix C, Attachment B, Chapter 3.2.1, presents an analysis of the anticipated impacts on visibility due to emissions from the proposed RICE project at nearby federal Class I areas, specifically, at Saguaro National Park (East and West). Both PDEQ and the National Park Service ("NPS") determined that the RICE project would have a negative impact on visibility at Saguaro National Park as modeled.

Based on the PLUVUE II modeling results, the Proposed TSD finds adverse impacts on visibility at Saguaro National Park for Case I (0.59% of daytime hours assuming grey as background color and 0.82% assuming black as background color) and for Case II (0.52% of daytime hours assuming grey as background color and 0.70% assuming black as background color). The NPS reran the PLUVUE II modeling with the same emission rates for Case I and found "visibility impacts at Saguaro east and west." Specifically, the NPS determined:

Saguaro east would see 13 hours per year with the highest Delta E of 4.658 and a Cp of 0.184. Saguaro

west will see 48 hours per year with the highest Delta E of 9.612 and a Cp of 0.413.

Based on the PLUVUE model, out of a total of 4,380 daylight hours per year, there will be, on average, 61 hours per year when a plume might be perceptible within the park.

The guidance that FLMs rely on to determine significance for visibility impacts, FLAG 2010, notes that for PLUVUE II analyses, the FLM would likely not object if Delta E is lower than 1.0 and Cp is lower than < 0.02. In other words, both PDEQ and the NPS determine that the RICE project would have an adverse impact on visibility at Saguaro National Park as modeled.

Response:

We disagree with the commenter's assertion that PDEQ and NPS have determined that the project results in an adverse visibility impact. Specifically, the commenter references FLAG 2010 guidance[1] regarding refined visibility modeling (PLUVUE II) results for color difference index (ΔE) and contrast (C) values, and asserts that therefore PDEQ and NPS have determined adverse visibility impacts because the project results in model results above these referenced values. We disagree with the commenter's characterization of these values from the FLAG 2010 guidance as bright line thresholds that indicate PLUVUE II impacts exceeding these values as adverse visibility impacts, and that PLUVUE II impacts not exceeding these values are not adverse. As noted by the commenter, FLAG 2010 guidance on this issue states that "For PLUVUE II analyses, the FLM would likely not object if ΔE<1.0 and ΔC < 0.02." This language does not indicate that impacts above these values require an FLM objection, nor does it preclude FLM objection in instances where PLUVUE II impacts fall below these values.

Rather, as discussed later in FLAG 2010 guidance: "If the estimated plume parameters exceed the aforementioned values, the FLM would rely on a case-by-case effects-based test (NPS 1993), taking into account magnitude, frequency, duration, and other factors, to decide whether to make an adverse impact determination."[2] NPS was consulted extensively during the PLUVUE II modeling to establish certain site-specific elements of the analyses, and was provided the model files developed by TEP for further analysis and model runs. NPS was provided the opportunity to review and comment on the draft permit and visibility modeling, and provided comments on February 8, 2018. In its response to PDEQ, NPS did not raise an objection to the draft permit, and noted that the proposed project would result in an improvement in visibility relative to the existing Units 11 and 12, based primarily upon lower peak 1-hr NO_x emission rates.

13. Comment:

The commenter asserts that the visibility modeling results underestimate visibility impacts because the modeled NO_x emission rates are misreported, as follows:

The modeling runs by far underestimate visibility impacts because the modeled NO_x emission rates are not consistent with the potential to emit for the RICE units. The Proposed Permit does not contain any permit conditions for the RICE units limiting short-term NO_x emission rates to the modeled short-term emission rates and the modeled NO_x rates are much lower than the combined potential to emit. Specifically, as shown in the excerpted table from the December 22, 2017 Final Air Quality Dispersion Modeling Protocol above, the modeled worst-case emission rates are 110.50 lbs/hour NO_x for Case I (30 minutes startup + 30 minutes normal operation) for all ten RICE Units or 11.05 lbs/hour NO_x per RICE unit, and 15.00 lbs/hour NO_x for Case 2 (60 minutes normal operation) for all ten RICE units, or 1.50 lbs/hour NO_x per RICE unit. These emission rates are considerably lower than those indicated as

[1] U.S. Forest Service, National Park Service, and U.S. Fish and Wildlife Service, Federal Land Managers' Air Quality Related Values Work Group (FLAG), Phase I Report – Revised, Report No. NPS/NRPC/NRR—2010/232, page 21, 10/2010. Hereafter, page 22

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RICE units is not enforceable. . . .

Response:

While we agree with certain elements of this comment, we disagree with the overall assertion that the NOx emission cap is unenforceable.

As noted by the commenter, and as discussed previously in our response to Comment II.B.1, we agree that the vendor emission specifications were not included in the docket. We have subsequently updated the Department website to include this information, which was summarized in Table A-2 Attachment A to Appendix C of the Proposed TSD.[9] In addition, we wish to clarify that the statement in Table A-2 that "Emissions presented are not enforceable by permit limits" is not intended to indicate that these values are unconstrained by permit limits, as implied by the commenter. As discussed in a similar response to Comment II.B.1, this language instead is intended to indicate that while these values do represent PTE, the literal ton/year and lb/hr values are not enforceable limits themselves. Rather, the permit establishes limitations for these pollutants through a combination of BACT limits and annual emission caps that constrain emissions from the RICE units.

As noted by the commenter, Condition II.C.9 of the proposed permit states that the permittee shall calculate NOx emissions using "[…] the vendor-guaranteed NOx emission rate for each startup event." We acknowledge that the emission rates provided by the vendor are not guaranteed, and have revised Condition II.C.9 to reference vendor specified rather than vendor guaranteed emission rates. In addition, following the close of the public comment period, we requested additional supporting information from the applicant regarding the development and basis for the startup emission rate specifications. We have included this information along with the original vendor specifications on the list of publicly available documents for this project on the Pima DEQ website.[10] [11] As discussed in this supporting information, the engine vendor developed start up emission specifications based upon a combination of information provided by the catalyst supplier, as well as field and laboratory data. In particular, the engine manufacturer relied upon data provided for catalyst conversion efficiencies in order to develop a simulation tool that, when combined with collected temperature and flow data from the engine, estimated NOx emission performance during the startup process. When compared to tested controlled emission rates, the simulation tool produced well correlated results.

More broadly, we disagree with the commenter's assertion that the NOx emission cap is unenforceable. Condition II.A.1.a of the Proposed Permit clearly establishes a 170.0 tpy NOx limit, based on a rolling 12-month total, that applies to all ten proposed RICE units. Additional specific conditions in the Proposed Permit require the permittee to perform performance tests and develop unit-specific NOx emission factors (Condition II.D.1 and 2), monitor control device and engine operating parameters (Condition II.B) including heat input and hours and modes of operation (i.e. startup-nonstartup), and record and report NOx emissions on a monthly basis (Condition II.C.9 and 10). Condition II.C.9 in particular specifies the variables that shall be used to calculate NOx emissions, and requires the inclusion of all emissions, including startup and non-startup emissions, from all RICE units. For periods of nonstartup operation, this involves calculation of heat input during periods of nonstartup operation combined with the NOx emission factor from the most recent source test. For periods of startup operation, this involves using records of startup emission events combined

[9] We wish to clarify that the 11.1 lb/hr NOx emission rate, which the commenter describes as the NOx startup emission rate, instead represents the maximum 1-hr NOx emission rate. As described in greater detail in the response to Comment II.B.13, the max 1-hr NOx emission rate represents 30 minutes of startup operation followed by 30 minutes of normal operation at full load. As listed in Table A-2 in Attachment A to Appendix C of the Proposed TSD, this corresponds to the startup emission rate of 10.3 lb/30 min, combined with controlled emission factor of 1.5 lb/hr over a 30 minute period. 10.3 + 0.75 = 11.1 lb/hr.

[10] "Estimated Flue Gas Emission Rates & Expected Emissions During Start-Up Rev 1.pdf", July 2, 2018.

[11] "Estimated Flue Gas Emission Rates & Expected Emissions During Start-Up Rev 1.pdf", July 5, 2018.

[9] "Vendor Emissions Specifications.pdf", September 21, 2017.

with the vendor supplied cold start emission factor applied to each startup event. In addition, Condition II.C.10 requires this calculation be performed on a monthly basis, both for calculating the most recent month's emissions and the 12 month rolling total. However, to address the commenter's concern regarding the lack of an unambiguous methodology for determining compliance, we have revised Condition II.C.9 to include a more detailed compliance determination methodology, expressed in the form of an equation. This methodology clearly indicates the emission factors and monitored data that will be used when calculating total NOx emissions from the engines.

Finally, we note that this compliance determination methodology includes certain elements that will inherently produce a conservative calculation of emissions (i.e., a tendency to over-calculate, rather than under-calculate, engine NOx emissions). When calculating startup emissions, the compliance determination methodology specifies the use of the cold start emission factor for all startup events, regardless of whether the startup event was a cold or warm startup. A cold startup event represents a startup that occurs when the SCR catalyst is at or close to ambient temperature, and generally occurs after a day or more of nonoperation. In this instance, the engine vendor has indicated in its supporting documentation that cold start conditions represent a startup occurring after 2-3 days of engine nonoperation. A warm startup event represents a startup that occurs after a shorter period of engine nonoperation, typically less than 24 hours, in which the SCR catalyst remains above ambient temperature and reaches minimum operating temperature more quickly. As indicated in the vendor specifications, cold startup emissions (10.3 lb/event) are approximately triple that of warm startup emissions (3.5 lb/event).[14] As a result, the majority of the engine startup events will be warm startup events, since even a single cold startup in a single day will ensure that each successive startup event that day is a warm startup. In the event that an engine has up to its 5 permitted startup events in a single day, the compliance determination methodology would assign a cold startup value to each event, resulting in reported emissions of 51.5 lbs of NOx attributable to startup events. Since 4 of the startup events would be warm and not cold startups, the actual amount of NOx emitted would be closer to 24.3 lbs of NOx, which represents an over-calculation margin of approximately 50%.

In addition, we note that for each of these pollutants, multiple source tests must be performed for each pollutant, corresponding to 25, 40, 75, and 100 percent of peak load (Proposed Permit Specific Condition II.D). In certain other instances, such information has been used to establish load-specific emission factors that will be paired with continuously recorded data indicating unit operating load in order to determine emissions on an hourly basis.[15] The methodology required by the proposed permit is more conservative as it does not allow for the use of load-specific emission factors, but instead requires the highest source test load result to be applied to *all* periods of normal (non-startup) operation and operating loads, irrespective of whether the engine actually operated at a lower-emitting load. This methodology inherently produces an over-calculation of reported emissions, and provides a greater assurance that the NOx annual emission limit will not be exceeded.

16. Comment:

The commenter asserts that while the proposed permit contains testing requirements for VOC, CO and PM10/PM2.5 emissions limits, it does not include reporting requirements. Thus, the emission limits for these pollutants are not enforceable.

Response:

The permit has been revised to address this comment. Permit Condition II.D.6 in Part B of the permit was added requiring reporting of performance test results to the Department in accordance with Condition XVII in Part A of the permit.

[14] Ibid. We note that the vendor specified startup emissions are expressed in terms of lb/30 min. Since Condition II.A.5 limits each startup to 30 minutes, we have expressed these emissions here on a lb/event basis.

[15] Order on Petition Nos. IV-2014-5 and VI-2013-10 at 1-17 (April 2, 2018) (Yuhuang Chemical II).

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conditions that strongly suggest that the plant is violating its permit limits (e.g., plumes are visible at the stacks, odors are present, solids settle in their yards or homes, or they experience adverse health effects), they are often powerless to prove such violations or to stop unlawful pollution because there are no monitoring data to support their claims.

Response:
We disagree with the commenter's assertion that the permit lacks sufficient testing, monitoring, and recordkeeping requirements to ensure that the permit limits are practicably enforceable. For an emissions limit to be enforceable as a practical matter, the permit must clearly specify how emissions will be measured or determined for purposes of demonstrating compliance with the limit[5,6] In addition, emission limitations must be supported by monitoring, recordkeeping, and reporting requirements that are "sufficient to enable regulators and citizens to determine whether the limit has been exceeded, and if so, to take appropriate enforcement action."[7]

We acknowledge that EPA has indicated, as noted by the commenter, that annual source tests alone are insufficient to assure compliance with emission limits. We note, however, that in the examples cited by the commenter, EPA indicated the insufficiency of annual source tests in the context of permit actions and permit conditions which relied upon source tests to the exclusion of other additional monitoring, either of operation of the emission unit in question, or of control devices being employed. The proposed permit for the RICE project requires annual source tests for NOx, CO, VOC, and PM10 PM2.5, but does not rely solely upon these source tests to ensure practicable enforceability of permit limits.[8] As described in greater detail below, the proposed permit requires additional monitoring and operating data collection to ensure compliance with the respective emission limits for these pollutants, as well as how compliance should then be demonstrated based on the data collected.

First, we note that the proposed permit requires extensive monitoring of control device operating parameters to assure that the control devices are operating appropriately at all times. The proposed permit requires each engine to operate with a Selective Catalytic Reduction (SCR) system (Proposed Permit Specific Condition II.A.1.c) as an add-on control device for NOx, and includes monitoring, recordkeeping, and reporting requirements of multiple SCR operating parameters on a continuous basis. SCR systems use an ammonia injection system and a catalyst bed to reduce NOx emissions. Ammonia selectively reduces NOx to N_2, and is injected into the exhaust gas stream upstream of a catalyst bed. The ammonia reacts with NOx to form N_2 on the catalyst surface, which specifically promotes the NOx to N_2 reaction. Temperature is a critical variable affecting the reaction, as optimum catalyst performance occurs in operating ranges varying from 400 to 800 deg F, depending upon specific catalyst composition. In addition to temperature, the ammonia injection rate is also crucial, and must be carefully maintained at an ammonia-to-NOx ratio that both effectively reduces NOx emissions and avoids excessive amounts of unreacted ammonia downstream of the catalyst bed. As a result, in addition to hours of operation of the engine, the proposed permit requires monitoring of the SCR ammonia injection rate and SCR outlet temperature, and also requires the use of an SCR process monitor that will calculate outlet NOx concentration (proposed permit specific condition II.A.1.c.iv).

Similarly, the permit includes monitoring of operating parameters for the oxidation catalyst. The proposed permit requires the use of an oxidation catalyst (proposed permit specific condition II.A.2.b and 3.b) as an add-on control device for purposes of meeting CO and VOC BACT limits. Oxidation catalyst systems consist of a specific catalyst mounted on a support material that is installed in a reactor vessel. As exhaust gases pass through the reactor, CO and VOC react with oxygen in the presence of the catalyst to form carbon dioxide. Temperature is a critical variable affecting this reaction, since oxidation catalyst also has an optimum temperature range, as well as a minimum

[5] Order on Petition No. IX-2011-1 at 10 (February 7, 2014) (Hu Honua I).
[6] Order on Petition No. IV-2010-4 at 15 (June 22, 2012) (Cash Creek).
[7] Order on Petition No. II-2000-07 at 7 (May 2, 2001) (Pencor-Masada).
[8] The proposed permit does not require stack tests for SO_2. Please see our response to Comment II.B. 11 for a discussion of practicable enforceability with regard to SO_2 PTE.

operating temperature below which catalyst effectiveness is negligible. As a result, the proposed permit requires monitoring, reporting, and recordkeeping of oxidation catalyst temperature. It also requires monitoring of pressure drop across the oxidation catalyst, which is an indicator of adequate flow across the catalyst bed. Also, the proposed project triggers Compliance Assurance Monitoring (CAM) requirements with respect to CO. We have updated the proposed permit and TSD to include the applicable requirements from 40 CFR part 64, which includes development of a CAM plan which will establish specific indicator ranges for catalyst temperature and catalyst pressure drop based upon the initial performance test.

Furthermore, to assure proper operation of the engines, the proposed permit requires the engines to operate in accordance with a site-specific monitoring plan and to install, operate, and maintain a continuous parameter monitoring system (CPMS) as required by NSPS subpart JJJJ and MACT subpart ZZZZ. The site specific monitoring plan is required to include elements such as performance criteria and design specifications for monitoring system equipment, and must establish measures for equipment performance evaluations, as well as ongoing operation, maintenance, and reporting and recordkeeping procedures.[9] The CPMS is required to collect information on engine operating parameters in accordance with the site specific monitoring plan on a continuous basis. The specific contents and operating parameters established in site specific monitoring plans vary, but in general are established based upon a combination of manufacturer specification and upon conditions observed during the initial compliance test. Combined with the CPMS, these measures work to ensure that the engines operate properly in accordance with manufacturer specifications, and in a manner consistent with the initial compliance test.

Finally, the Proposed Permit requires the data generated by the monitoring and testing requirements contained in Section II.B (PSD and BACT Monitoring Requirements) and Section II.D (PSD and BACT Testing Requirements) to be used to demonstrate compliance with the respective pollutant emission limits, including the NOx annual emission cap. As explained in greater detail in our response to Comment II.B.9 below, fuel usage records, source test results, and vendor startup emission rates shall be used to calculate NOx emissions from all ten RICE units on a monthly basis, and as a 12-monthly rolling total.

9. Comment:
The commenter asserts that the permit conditions are insufficient to ensure compliance of the proposed RICE units with the 170 tpy NOx emission cap. The following excerpt describes the commenter's assertion in more detail:

> First, the Proposed Permit fails to establish an unambiguous methodology for calculating NOx emissions from the emission test. Simply referring to the parameters that are part of the calculation is inadequate to ensure that the Applicant correctly calculates NOx emissions. Thus, the NOx emission cap is not enforceable. The Proposed Permit should be revised to include an equation that lays out the emission calculation in detail. Preferably, the Proposed Permit should be revised to require installation of NOx CEMS which would eliminate the need for manual calculations.

Second, one of the parameters that are part of the proposed NOx emission calculation is the "vendor-guaranteed NOx emission rate for each startup event." This emission rate is nowhere to be found in the Proposed Permit. Presumably, the Proposed Permit refers to the vendor-supplied (not vendor-guaranteed) startup emission rate of 11.1 lbs/hour of NOx per RICE unit presented in Attachment A to Appendix of the Proposed TSD, Table A-2. A vendor guarantee for this emission rate is nowhere to be found in the docket. Further, PDEQ recognizes that the emission rates provided by the vendor are not guaranteed. Specifically, Footnote 10 to Table A-2 clearly states "PTE emissions using vendor supplied controlled emission rates for comparative purposes only. Emissions presented are not enforceable by permit limits." Thus, the startup emission rate for NOx is not supported and, consequently, the emission cap for NOx emission from all ten

[9] For a complete list of required site-specific monitoring plan requirements, see 40 CFR 63.6625(b)(1).

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consider emission limits for individual engines necessary to ensure project emission increases remain below the PSD SER for NOx.

Second, we note that the commenter is correct that the PTE of the engines, based upon 8760 hours/year of operation and a short-term NOx emission rate of 59.1 lb/hr, which corresponds to the NSPS subpart JJJJ emission standard of 1.0 g/hp-hr, is higher than the 170 tpy NOx emission cap. However, we note that this calculation does not reflect the vendor emission specifications for these engines. As discussed in our response to Condition II.B.1, we have updated the record to include these vendor emission specifications, which include the vendor emission data for startup events, as well as emission rates during normal operations that reflect the use of Selective Catalytic Reduction (SCR) for NOx control. If established limitations are practicably enforceable, they may be relied upon to legally restrict potential emissions. As discussed in greater detail in our response to Comment II.B.8, the proposed permit contains an emission cap across all ten proposed engines limiting NOx PTE to 170 tpy, a requirement for each engine to operate with a Selective Catalytic Reduction (SCR) system for NOx control, and multiple requirements for emission testing and operational monitoring of the engines. Conditions II.B.9 and 10 contain a compliance determination method to calculate total NOx emissions from the project on a monthly basis. Taken together, these requirements provide a practicably enforceable limitation on total NOx emissions to ensure detection of an exceedance of the NOx PSD significance threshold.

6. Comment:
As described in previous comments, the commenters assert that the project triggers PSD review for NOx, and that PDEQ must perform a BACT analysis for NOx and established an emission limit for NOx that constitutes BACT. The commenters provide a review and description of recent PSD permits for RICE units, and assert that BACT for NOx is SCR, with a corresponding emission rate of 3.10 lbs/hr based on an emission factor of 0.0525 g/bhp-hr.

Response:
We disagree that the project triggers PSD review for NOx, and that a NOx BACT determination is warranted. The commenter has previously asserted that the project is a major modification for NOx, and has raised multiple concerns regarding the NOx netting analysis and overall emissions from the RICE project. Please refer to our responses to Comments II.B.2 through 5 for further explanation on why the project does not trigger PSD review for NOx.

7. Comment:
The commenter notes that the proposed permit determined BACT for PM10/PM2.5 as good combustion practices, and established an emission limit of 2.5 lb/hr (per engine) for periods of normal operation based on an emission factor of 0.04 g/hp-hr. The commenter asserts that this emission rate does not represent BACT for PM10/PM2.5. Specifically, the commenter notes that a considerably lower BACT limit was permitted by the Tehama County Air Pollution Control District (APCD) and can be found in CARB's BACT Clearinghouse and the inventory of BACT determinations for RICE units maintained by the South Coast Air Quality Management District. Tehama County APCD established a lower BACT for NEO California Power, LLC, which operates RICE units of a comparable type, as well as comparable fuel use. The PM10 BACT emission limit established for the NEO California Power RICE units is 1.18 lb/hr based upon an emission factor of 0.02 g/hp-hr PM10, which the commenter asserts is BACT for the project.

Response:
We disagree with this comment. We acknowledge that the 0.02 g/hp-hr PM_{10} BACT limit established by Tehama County APCD for NEO California Power (now California Power Holdings, Inc.) is more stringent than the basis for the $PM_{10}/PM_{2.5}$ BACT limit for the Sundt RICE units, which is 0.04 g/hp-hr. However, we note that the current Permit to Operate for California Power Holdings[4] indicates that

[4] Tehama County APCD Permit No. PTO220

compliance with this PM_{10} limit shall be determined either via EPA Test Method 5/ARB Method 5, or per a calculated emission rate based on 0.02 g/bhp-hr. In conversations with Tehama County APCD, we have not been able to identify either a recent PM_{10} source test or an initial source test. This would indicate that the California Power Holding RICE units are using a calculated emission rate of 0.02 g/bhp-hr, as opposed to Method 5 source tests, as the method of demonstrating compliance. Given the lack of source dest data from the California Power Holdings units demonstrating compliance with their PM_{10} BACT limit, we do not consider a 0.02 g/hp-hr PM_{10} emission limit to be demonstrated in practice, and have not updated the BACT analysis for the RICE project to include this determination.

8. Comment:
The commenter asserts that periodic source tests are insufficient to ensure the practical enforceability of permit emission limits. The commenter specifically notes that NOx and CO CEMS are routinely required for natural gas-fired combustion units, including RICE units, and asserts that PDEQ must require CEMS in order to ensure that permit emission limits are practicably enforceable.

The following excerpt describes the commenter's assertion in more detail:

The Proposed Permit contains no testing requirements other than these infrequent stack tests (biannual after initial source test for each RICE unit) to determine compliance with the Proposed Permit PSD and BACT emission limits for NOx, VOC, CO, and PM10/PM2.5. Infrequent stack tests are inadequate to determine whether permit limits are being met routinely, day in and day out. EPA itself has stated that annual stack tests are not sufficient to assure compliance with emissions limits.

First, stack tests normally last only a few hours (two to six hours). Annual testing therefore may not be representative for emissions during routine operations during the remaining hours of the year. Bi-annual testing, as proposed here is even less representative. Second, it is well known that "[m]anual stack tests are generally performed under optimum operating conditions, and as such, do not reflect the full-time emission conditions from a source." A widely used handbook on Continuous Emissions Monitoring ("CEMs") notes, with respect to manual source tests for PM10, that: "Due to the planning and preparations necessary for these manual methods, the source is usually notified prior to the actual testing. This lead time allows the source to optimize both operations and control equipment performance in order to pass the tests." In other words, maintenance is performed in advance of the test to ensure that the emission-generating process is finely tuned. Sometimes, a pre-test is conducted and additional maintenance and tuning performed to assure the source passes.

It is essential that monitoring be performed more frequently than specified by the biannual source test requirements in the Proposed Permit. Stack emissions can be accurately monitored with Continuous Emissions Monitors ("CEMs"). CEMS are electro-mechanical instruments, usually installed in the facility's exhaust or smoke stacks, which sample, analyze, measure, and record the amount of pollutants passing through the stack. CEMS have been developed to measure various types of pollutants emitted by stationary sources, including NOx, CO, and opacity. NOx and CO CEMS are routinely required for natural gas-fired combustion units, including RICE units, and can detect violations that inspectors cannot:

According to EPA compliance officials, inspectors have difficulty judging visible emissions at night and in adverse weather, whereas CEMS are not affected by these conditions. More importantly, gaseous emissions, such as SO, and NOx, are generally not visible, whereas CEMS consistently measure these gases directly and reliably. For some gaseous pollutants, inspectors often can only infer compliance by comparing existing process and control system operating conditions with those recorded during stack testing. However, according to EPA, stack test data are collected under finely tuned process and control system operating conditions, and thus may be atypical of tests conducted under normal operations, further adding to the difficulty of detecting violations of permit conditions for gaseous pollutants.

Unless supplemental monitoring such as CEMS is added to the Proposed Permit, community members will not be able to protect themselves against harmful emissions and local, state, and federal regulatory agencies cannot detect and cure violations of permit conditions. Indeed, even when locals observe

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project, and ensures that emission decreases associated with the shutdowns are creditable.

3. Comment:
The commenter asserts that the 180 day period between startup of the new RICE units and shutdown of Units 11 and 12 provided by Condition B.V.E.1 and 2 is relying upon an improper interpretation of the shakedown period allowed for replacement units established in PCC §17.04.340(A)(148)(g) and 40 CFR §52.21(b)(3)(viii). The commenter asserts that the RICE units are not "replacement units", and that therefore any emission decreases from the shutdown of Units 11 and 12 may not be used as contemporaneous emission decreases in the netting analysis.

The following excerpt describes the commenter's assertion in more detail:

The proposed overlap period of 180 days between startup of the new RICE units and shutdown of the existing boilers may be relying on misinterpretation of PCC §17.04.340(A)(148)(g) and 40 CFR §52.21(b)(3)(viii), which allow for a "shakedown" period of 180 days for "replacement units:"

An increase that results from a physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed one hundred eighty days.

However, the RICE units are not replacement units for the steam electric generators Units 11 and 12. Since the Pima County Code does not include a definition for "replacement unit," PDEQ should look to the federal definition, and also apply a common-sense definition to define replacement unit. Notably, nowhere does the Applicant claim that the RICE project is a replacement unit.

The meaning of a "replacement unit" is defined in 40 CFR §52.21(b)(33), which requires that all of the criteria listed in the following subsections are met:

> (i) The emissions unit is a reconstructed unit within the meaning of § 60.15(b)(1) of this chapter, or the emissions unit completely takes the place of an existing emissions unit.
> (ii) The emissions unit is identical to or functionally equivalent to the replaced emissions unit.
> (iii) The replacement does not alter the basic design parameters (as discussed in paragraph (cc)(2) of this section)32 of the process unit.
> (iv) The replaced emissions unit is permanently removed from the major stationary source, otherwise permanently disabled, or permanently barred from operation by a permit that is enforceable as a practical matter. If the replaced emissions unit is brought back into operation, it shall constitute a new emissions unit.

Here, the RICE units do not comply with the requirements for "replacement units" specified in in sections (ii) and (iii). First, the RICE units are not "identical or functionally equivalent" to the existing Units 11 and 12 pursuant to 40 CFR §52.21(b)(33)(ii) as they employ fundamentally different technologies to generate electricity, i.e., internal combustion versus steam turbine cycle, respectively, as recognized by the Proposed TSD. Second, the RICE units alter the basic design parameters of the process unit pursuant to 40 CFR §52.21(b)(33)(iii). Here, the steam turbine cycle Units 11 and 12 are permitted to fire different fuels than the RICE units and have substantially different maximum hourly heat input and maximum hourly electric output rates.

Response:
As noted in our response to Comment II.B.2, we have updated Conditions V.E.1 and 2 to require permanent shutdown of Units 11 and 12 prior to initial startup of the first RICE unit. Since this eliminates the 180 day period between startup of the new RICE units and shutdown of Units 11 and 12, we consider the remainder of the comment regarding whether these units are "replacement units" that qualify for the 180 day shakedown period described in 40 CFR 52.21(b)(3)(viii) to be rendered moot.

4. Comment:
The commenter cites the language of Condition B.V.E.1 and 2, which establish the shutdown requirements for Units 11 and 12:

> 1. The permittee shall shutdown permanently either Unit 11 or Unit 12 within 180 days following initial startup of the first RICE unit.
> 2. The permittee shall have shutdown permanently both Unit 11 and Unit 12 within 180 days following initial startup of the sixth RICE unit.

The commenter asserts that the language of Condition B.V.E.1 and 2 creates a "phased shutdown" of Units 11 and 12 that does not require both existing units to be shut down should the applicant decide to only construct the first set of RICE units. The commenter notes that this would allow an operating scenario in which one of either Units 11 and 12 could operate and generate emissions that overlap with the first set of RICE units, and assert that the emission decreases associated with the shutdown of the second existing unit cannot be used as creditable emission decreases for purposes of NOx netting.

Response:
As noted in our response to Comment II.B.2, we have updated Conditions V.E.1 and 2 to require the shutdown of both Units 11 and 12 prior to initial startup of the first RICE unit, eliminating what the commenter describes as a "phased shutdown". As a result, we consider these changes to the final permit sufficient to address the commenter's concern regarding a "phased shutdown."

5. Comment:
The commenter asserts that the RICE project constitutes a PSD major modification for NOx because the 170 tpy emission cap for the RICE project does not limit total combined NOx emissions to equal or less than 40 tpy. Specifically, the commenter asserts that NOx emissions from the RICE units are limited only by Proposed Permit, Condition B.II.A.1.a, which implements the proposed permit cap of 170.0 tons/year as a 12-month rolling total for all ten RICE units combined. The Proposed Permit does not include any permit conditions limiting NOx emissions on an annual basis for individual RICE units, which each have a potential to emit of 258.9 tons/year of NOx. The commenter asserts that each RICE unit has a NOx potential to emit of 258.9 tpy, which would emit over 40 tpy NOx after only 270.7 hours/year of operation. In addition, the commenter notes that the applicant has indicated an anticipated operation of one of the RICE units for 8,760 hours/year. As a result, the commenter asserts that an annual emission cap across all of the RICE units is not sufficient to determine compliance with the PSD significant emission rate, and states that permit conditions establishing a 4 tpy NOx limit for each RICE unit are required to ensure the project does not trigger PSD review for NOx.

Response:
We disagree with this comment. First, we disagree with the commenter's assertion that limits for individual emission units are required to ensure that the project does not result in a NOx increase greater than 40 tpy. As noted in the permit application and proposed TSD, the net emission increase from the project is 30.6 tpy NOx, which is below the NOx PSD significant emission rate (SER) threshold. This net emission increase consists of the project increase of 170 tpy NOx, consistent with the 170 tpy emission cap for the engines, combined with a creditable emission decrease of 139.4 tpy NOx based upon the shutdown of Units 11 and 12.[1] We note that the 170 tpy NOx emission cap established by Condition B.II.A.1.a applies to all emissions from all ten proposed engines. Because this emission cap applies to the entire group of ten engines, it constrains NOx emissions from the project to 170 tpy. When combined with the creditable NOx decreases from the Unit 11 and 12 shutdowns, this results in a net increase of NOx below the PSD SER threshold. As a result, we do not

[1] The commenter has asserted in a separate comment that the emission decrease from Units 11 and 12 are not creditable. These concerns are addressed separately in Comment II.B.2.

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> limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.

PCC §17-04.340(A)(135); 40 CFR 52.21(b)(4). The Proposed TSD should be revised to reflect the potential to emit for all emissions units consistent with this definition.

Further frustrating review, the Proposed TSD presents two different definitions for the term "potential to emit ("PTE") for the RICE units. Specifically, the emission calculations provided in Attachment A to Appendix C of the Proposed TSD, which purportedly support the potential to emit for these units presented in the summary table "GS Facility Wide Potential to Emit (tons/year) Summary," refer to "Proposed Potential to Emit" and "Estimated Potential to Emit." The former is consistent with the potential to emit presented in the summary table and the latter is based on vendor supplied startup and controlled emission rates, which are lower and were used for modeling purposes. (Modeling must be based on the maximum emission rates incorporated into enforceable permit condition: see Comment VII.B). In sum, the Proposed TSD frustrates public review and should be revised to address the issues outlined above. In order to facilitate review, the Proposed TSD should include tables for BACT emission limits and not emissions increases for all pollutants.

The emission calculations provided in Appendix C, Anachment A, to the Proposed TSD, which purport to support the potential to emit provided in the "GS Facility Wide Potential to Emit (tons/year) Summary table, refer a number of times to vendor information provided by TEP in a letter entitled "Vendor Emissions Performance Specifications, H. Wilson Sundt Generating Station Rice Project," dated September 21, 2017. This document is neither attached to the Proposed TSD nor can it be found in the record. Without the document in the permitting record, the assumed emission rates from this letter, specifically the cold startup emission factors and 60-minute average flue gas emission rates after control system startup for 25% to 100% engine loads, are not supported. Consequently, the emission calculations for potential to emit for the RICE units are not supported. This document must be provided with the Proposed TSD

Response:
We agree that the Vendor Emissions Performance Specifications, dated September 21, 2017, were not included among the documents available on the Department website during the public comment period. In response to this comment, we obtained a release of a claim of confidentiality on the vendor emission specifications. We have updated the Department website with the vendor specifications, which include the vendor emission data for startup events, as well as emission rates during normal operations that reflect the use of Selective Catalytic Reduction (SCR) for NOx control. In addition, in order to address the commenter's concern and to facilitate review, we have updated the TSD to include summary tables of BACT emission limits and not emission increases for all pollutants, and have included the vendor emission specifications as an attachment to the TSD..

Regarding the "Facility Wide Potential to Emit Summary" table in Section IV of the Proposed TSD, we wish to clarify that the language explaining the content of the summary table, such as the statement "These emission figures are not meant to be emission limitations of any form", is not intended to indicate that these values do not reflect the true PTE, as asserted by the commenter. Rather, it is intended to indicate that while the table values represent PTE, they may not themselves represent enforceable emission limitations. For example, CO emissions for each RICE unit are constrained by emission limitations established pursuant to the CO BACT analysis. As described on Page 12 of 34 in Attachment C (BACT Analysis) to Appendix C of the Proposed TSD, CO BACT for nonstartup operations was determined to be 4.43 lb/hr, while CO BACT for startup operations was determined to be specific work practice standards during startup operations that represent a vendor specified startup

emission rate of 9.1 lb/30 min.[1] These BACT limits, in addition to a requirement to limit startups for each RICE unit for each calendar day to no more than 5 startup events, are enforceable limitations that are included in Condition II.A of the Proposed Permit. As presented in the RICE Project Emission Calculations included in Attachment A to Appendix C of the Proposed TSD, these limitations have the effect of limiting the CO PTE of each engine to 13.3 lb/hr and 25.7 tpy, which are the values listed for each engine as CO PTE in the "Facility Wide Potential to Emit Summary" table in Section IV of the Proposed TSD. As a result, while the values for the RICE units contained in this table may not necessarily represent enforceable emission limits themselves, we consider them to accurately reflect PTE of the RICE units.[2]

The RICE Project Emission Calculations contained in Attachment A to Appendix C of the TSD contain the columns labeled "Proposed Potential to Emit" and "Estimated Potential to Emit" noted by the commenter. We note that the commenter's assertion that the "Estimated Potential to Emit" values were used for modeling purposes, while not inaccurate, does not adequately characterize the development of model emission rates. Please consult the Air Quality Analysis contained in Attachment A to Appendix C of the TSD, as well as our responses to Comment II.B.13 and 14, for a more detailed explanation of model emission rates.

2. Comment:
The commenter asserts that emission decreases from Units 11 and 12 are not contemporaneous with the project, and therefore cannot be used as creditable emissions decreases. The commenter notes that the project nets out of PSD review for NOx by relying upon the emission reductions from the shutdown of Units 11 and 12, combined with the project NOx emission cap of 170 tpy, to limit project increases to below the NOx PSD SER of 40 tpy. Citing to PCC §17-04.340(A)(148) and 40 CFR §52.21(b)(3)(i)(b), the commenter notes that any increases or decreases in actual emissions at the major stationary source that are used to calculate a net emissions increase with respect to any regulated NSR pollutant must be "contemporaneous with the particular change", and that an increase or decrease in actual emissions is "contemporaneous" only for:

> (a) The date five years before construction on the particular change commences; and
> (b) The date that the increase from the particular change occurs.

The commenter notes that Conditions B.V.F.1 and 2 of the proposed permit do not require shutdown of Units 11 or 12 until within 180 days following initial startup of the RICE units. The commenter asserts that because the shutdown of Units 11 and 12 will not occur until after the emission increase from the particular change occurs (i.e., RICE unit startup), the emission decrease occurs outside of the contemporaneous window and is therefore not creditable.

Response:
We agree with this comment. Conditions B.V.F.1 and 2 of the proposed permit do not ensure that the Unit 11 and 12 shutdowns occur within the contemporaneous window for this project, which would not make their emissions reductions creditable. As a result, we have updated these permit conditions to require permanent shutdown of Units 11 and 12 prior to initial startup of the first RICE unit. This will ensure that the shutdown of Units 11 and 12 occur within the contemporaneous window for the RICE

[1] Startup emission rates are expressed in units of both lb/event and lb/30 minutes. Since Condition II.A.5 limits startups to 30 minutes in duration, these terms can be used interchangeably.
[2] By contrast, NOx PTE does represent an enforceable limitation, as Condition II.A.1.a establishes an emission cap of 170 tpy across the 10 RICE units.

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I. Introduction

On February 9, 2015 the Pima County Department of Environmental Quality (PDEQ) proposed to approve, subject to public review, a prevention of Significant Deterioration (PSD) permit for Tucson Electric Power (TEP) Irvington/H.Wilson Sundt Generating Station that would authorize construction, and operation of ten natural gas fired, reciprocating internal combustion engines ("RICE"). The permit was developed in collaboration with the Environmental Protection Agency (EPA) and the National Park Service (NPS).

The public comment period for the proposed permit was originally scheduled to last 30 days. However, the public comment was substantially extended, and it was officially closed on March 20, 2015. PDEQ announced the public comment period through public notices published in the Arizona Daily Star and the Daily Territorial (in English and Spanish) and on the PDEQ website. PDEQ also distributed the Spanish and English public notices to a significant number of interested parties in accordance to 40 CFR part 124, including notices sent by mail, and e-mail.

II. Comments on Specific Provisions of the Draft Permit

A. Comments from Public Referencing Specific Permit Conditions

1. Comment:
Referencing Permit Condition V.E.1: TEP should not be allowed to overlap the new units with the operation of the old units and the proposed permit allows this.

Response:
The permit has been revised to address this comment. As described in more detail in Comments II.B.2 through 4 below, the revised permit requires the permanent shutdown of Units 11 and 12 prior to the initial startup of any one of the RICE units (RICE01 through RICE10).

B. Comments from Sierra Club Referencing Specific Permit Conditions

1. Comment:
The commenter asserts that the information provided in the proposed Technical Support Document does not properly document or establish the potential to emit of the project, citing several issues. The commenter asserts that in order to facilitate review and address the noted issues, the Proposed TSD should include tables for BACT emission limits and net emissions increases for all pollutants.

The following excerpt describes the commenter's assertion in more detail.

[...]The Proposed TSD explains with the "potential to emit" presented in the IGS Facility Wide Potential to Emit (tons/year) Summary table:

> The following table summarizes IGS annual potential to emit of air pollutants by each emission unit and by facility-wide total. The emission estimate is to establish "major source" status of IGS pursuant to CAA Sec 302(j). Other use with the estimate may include comparing source potential-to-emit with emissions inventory and test data, or with emission rates allowable by relevant standards. This emission estimate is not meant to establish any baseline emission levels. These emission figures are not meant to be emission limitations of any form.

The Proposed TSD does not explain why the "emission figures" do not reflect the true potential to emit for the Facility and its equipment based on the permit conditions. The term "potential to emit" is a defined term for purposes of PSD review:

> Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational

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EXHIBIT 6

PIMA COUNTY

ENVIRONMENTAL QUALITY

RESPONSES TO PUBLIC COMMENTS

On the Clean Air Act
Prevention of Significant Deterioration of Air Quality Draft Permit

For

TUCSON ELECTRIC POWER (TEP) IRVINGTON/H.WILSON SUNDT GENERATING STATION (IGS)
3950 E. Irvington Road • Tucson Arizona 85714
Air Quality Permit #1052

August 8, 2018

Pima County Department of Environmental Quality
33 North Stone Avenue, Suite 700
Tucson, AZ 85701

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EXHIBIT 5

PIMA COUNTY DEPARTMENT OF ENVIRONMENTAL QUALITY

AIR PROGRAM

33 N. Stone Avenue, Suite 700 • Tucson, AZ 85701 • Phone: (520) 724-7400

PREVENTION OF SIGNIFICANT DETERIORATION AIR QUALITY PERMIT

(As required by Title 17.12, Article II, Pima County Code)

ISSUED TO

TUCSON ELECTRIC POWER
IRVINGTON GENERATING STATION
3950 EAST IRVINGTON ROAD
TUCSON, AZ 85714

This air quality permit does not relieve Tucson Electric Power from the responsibility to comply with any other applicable provisions of the Clean Air Act or other federal, state, and local requirements.

This PSD permit for the TEP Irvington Generating Station shall become effective 30 days after service of this notice of the final permit decision, unless a petition for review is properly and timely filed with the EAB per 40 CFR 124.19 or 40 CFR 49.150(d). In the event that a petition for review is filed with the EAB, construction of the facility is not authorized under this permit until resolution of the EAB petition(s). See 40 CFR 124.16.

THIS PERMIT ISSUED SUBJECT TO THE SPECIFIC AND GENERAL CONDITIONS IDENTIFIED IN THIS PERMIT

PERMIT NUMBER 1052 | PERMIT CLASS I

ISSUED: August 8, 2018 | EXPIRES: August 7, 2023

Rupesh Patel, Air Program Manager, PDEQ

SIGNATURE | TITLE

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SUMMARY

This Class I, Title V air quality permit is issued to Tucson Electric Power Company (TEP), the Permittee, for the continued operation of its Irvington Generating Station (IGS), also known as the H. Wilson Sundt Generating Station. This permit allows the permittee to construct and operate the equipment listed in Attachment 2. Approval to construct becomes invalid if construction is not commenced within 18 months after the Department issues this permit or if construction is discontinued for a period of 18 months or longer.

TEP-IGS is a Class I Major Source. The potential emission rates of PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, and VOC exceed 100 tons. In addition TEP-IGS has potential emission rates of hazardous air pollutants in excess of 25 tons per year Total HAPs, and in excess of 10 tons per year of a single HAP; and CO_2e in excess of 100,000 tpy. The facility operates within an area classified as being in attainment for all criteria pollutants.

The facility is a stationary source which generates electricity and consists primarily of fossil-fuel fired electric utility steam generating units (EGU's), stationary combustion turbines with starter engines, cooling towers, emergency generators, and other processes and equipment associated with power production. There are four fossil fuel fired EGU's, designated as Units 1 through 4, and two simple cycle peaking internal combustion turbines with black start capability, designated as IGT1 and IGT2. The net generating capability for each of the EGU's is 81 megawatts (MW), 81 MW, 104 MW, and 156 MW respectively and the combined net capability total for IGT1 and IGT2 is 48 MW.

The EGU's, Units 1-4 are subject to applicable provisions of the Acid Rain Program of the Clean Air Act (40 Code of Federal Regulations (CFR) 72-80).

In addition, Unit 4 is subject to the Arizona Regional Haze State and Interstate Visibility Transport State Implementation Program requirements for Best Available Retrofit Technology (BART) (FIP Final Rule, 40 CFR 52.145(j), Promulgated September 3, 2014, Federal Register Vol. 79, No. 170.) This rule is effective October 3, 2014 and requires compliance no later than December 31, 2017 when choosing to combust only natural gas or natural gas combined with landfill gas. TEP provided notification to the United States Environmental Protection Agency (US EPA) Director of Enforcement Division (EPA Region 9) for IGS Unit 4 that it will comply with the Regional Haze requirements by selecting the better than BART (switching to firing natural gas and landfill gas exclusively). The Permittee has stopped burning coal and fuel oil in Unit 4 and suspended the use of equipment necessary to fire coal and fuel oil in unit 4.

Reciprocating Internal Combustion Engine (RICE) Project: TEP has proposed to expand operations at the IGS facility to maintain load-interchange-generation balance within its designated distribution area. The proposed expansion includes the addition of up to ten RICE units, each with a nominal net generating capacity of 19 MW. Each RICE will be equipped with an oxidation catalyst system and a selective catalytic reduction (SCR) system. The oxidation catalyst will control emissions of volatile organic compounds (VOC), carbon monoxide (CO), and organic hazardous air pollutants and the SCR system will control emissions of nitrogen oxides (NOx).

The RICE project constitutes a major modification pursuant to Pima County Code (PCC) §17.04.340(A)(127) and 40 CFR §52.21(a)(2)(iv) and (b)(2). The emissions increases from the RICE project exceed the prevention of significant deterioration (PSD) significant levels for six pollutants: NO_x, VOC, CO, PM10, PM2.5, and GHG. The Permittee has accepted the following requirements to ensure that the net emissions increase in NO_x as a result of the RICE project is not significant and therefore not subject to PSD requirements:

1. Both of the existing fossil fuel fired units (Unit 1 and Unit 2) will be shut down permanently prior to the initial startup of any one of the RICE units (RICE01 through RICE10).

2. The NO_x emissions from the ten RICE will be limited to 150.0 tpy.

Pursuant to PSD requirements, an air dispersion modeling impact analysis, an additional impact analysis, and a BACT determination were conducted as part of the permit application process for the RICE project. BACT-based emission limitations were determined for the RICE and for fugitive emissions of VOC, and CO_2e.

The RICE units (RICE01-RICE10), each are subject to applicable provisions of the New Source Performance Standard (NSPS) for Stationary Spark Ignition RICE (40 CFR 60, Subpart JJJJ) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Stationary RICE (40 CFR 63 subpart ZZZZ).

This Class I, Title V air quality permit, includes the significant revision to the existing permit to incorporate the RICE Project expansion of the TEP-IGS operations.

Alternate Operating Scenarios: The permit contains two alternate operating scenarios to install and operate a third internal combustion turbine < 25 MW (IGT3) limited to less than significant levels of NO_x and CO and to be fired exclusively with natural gas. The proposed installation of Unit IGT3 will be subject to 40 CFR 60 Subpart GG or 40 CFR 60, Subpart KKKK.

PART A: GENERAL CONDITIONS

(References to A.R.S. are references to the Arizona Revised Statutes, references to A.A.C. are references to the Arizona Administrative Code, and references to PCC are references to Title 17 of the Pima County Code)

I. PERMIT EXPIRATION AND RENEWAL [PCC 17.12.050.A & PCC 17.12.060.D.1]

A. This permit is valid for a period of five years from the date of issuance.

B. The Permittee shall submit an application for renewal of this permit at least 6 months, but not more than 18 months prior to the date of permit expiration.

II. COMPLIANCE WITH PERMIT CONDITIONS [PCC 17.12.040.A.8.a & 8.b]

A. The Permittee shall comply with all conditions of this permit including all applicable requirements of the Arizona air quality statutes and Pima County air quality rules. Any permit noncompliance constitutes a violation of the Arizona Revised Statutes and is grounds for enforcement action; for permit termination, revocation and reissuance, or revision; or for denial of a permit renewal application. In addition, noncompliance with any federally enforceable requirement constitutes a violation of the Clean Air Act.

B. It shall not be a defense for a 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.

III. PERMIT REVISION, REOPENING, REVOCATION AND REISSUANCE, OR TERMINATION FOR CAUSE [PCC 17.12.040.A.8.c & PCC 17.12.130]

A. The permit may be revised, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a permit revision, revocation and reissuance, termination; or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

B. The permit shall be reopened and revised under any of the following circumstances:

1. Additional applicable requirements under the Clean Air Act become applicable to a Class I source. Such a reopening shall only occur if there are three or more years remaining in the permit term. The reopening shall be completed no later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless an application for renewal has been submitted pursuant to PCC 17.12.140.B. Any permit revision required pursuant to this subparagraph shall comply with the provisions in PCC 17.12.140 for permit renewal and shall reset the five-year permit term.

2. Additional requirements, including excess emissions requirements, become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the Class I permit.

3. The Control Officer or the Administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

4. The Control Officer or the Administrator determines that the permit needs to be revised or revoked to assure compliance with the applicable requirements.

C. Proceedings to reopen and reissue a permit, including appeal of any final action relating to a permit reopening, shall follow the same procedures as apply to initial permit issuance, and shall affect only those parts of the permit for which cause to reopen exists. Such reopenings shall, except for reopenings under condition III.B.1 above, affect only those parts of the permit for which cause to reopen exist. Such reopenings shall be made as expeditiously as practicable. Permit reopenings for reasons other than those stated in condition III.B.1 above shall not result in a resetting of the five-year permit term.

IV. POSTING OF PERMIT [PCC 17.12.060 & ARS 49-485]

The Permittee, who has been granted an individual permit by PDEQ or a general permit and authorization to operate (ATO), shall maintain a complete copy of the permits and ATO's onsite. If it is not feasible to maintain a copy of the permit and ATO onsite, the Permittee may request, in writing, to maintain a copy of the permit at an alternate location. Upon written approval by the Control Officer, the Permittee must maintain a complete copy of the permit at the approved alternative location. In addition, the machine(s), equipment, device(s), or other article(s) for which the permit or ATO has been issued shall be affixed with a unique and clearly visible and accessible identification (ID).

V. FEE PAYMENT [PCC 17.12.040.A.9 & PCC 17.12.220]

The Permittee shall pay fees to the Control Officer pursuant to PCC 17.12.330.

VI. ANNUAL EMISSIONS INVENTORY QUESTIONNAIRE [PCC 17.12.160]

A. The Permittee shall complete and submit to the Control Officer an annual emissions inventory questionnaire. The questionnaire is due by March 31 or ninety days after the Control Officer makes the request and inventory form available, whichever occurs later, and shall include emission information for the previous calendar year. These requirements apply whether or not a permit has been issued and whether or not a permit application has been filed.

B. The questionnaire shall be on a form provided by or approved by the Control Officer and shall include the information required by PCC 17.12.160.

VII. COMPLIANCE CERTIFICATION [PCC 17.12.040.A.5 & PCC 17.12.060.A.2]

The Permittee shall submit a compliance certification to the Control Officer that describes the compliance status of the source with respect to each permit condition. Certifications shall be submitted on the dates and frequency specified in Part B of this permit.

A. The compliance certification shall include the following:

1. Identification of each term or condition contained in the permit including emission limitations, standards, or work practices that are the basis of the certification;

2. Identification of the method(s) or other means used by the Permittee for determining the compliance status with each term and condition during the certification period. Such methods and other means shall include, at a minimum, the methods and means required under PCC 17.12.040(A)(3). (monitoring including the related recordkeeping and reporting sections of this permit. If necessary, the Permittee also shall identify any other material information that must be included in the certification to comply with Section 113(c)(2) of the Clean Air Act, which prohibits knowingly making a false certification or omitting material information;

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3. The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall be based on the methods or means designated in condition VII.A.3 above. The certification shall identify each deviation and take it into account for consideration in the compliance certification;

4. For emission units subject to 40 CFR Part 64, the certification shall also identify as possible exceptions to compliance any period during which compliance is required and in which an excursion or exceedance defined under 40 CFR Part 64 occurred;

5. All instances of deviations from permit requirements reported pursuant to condition XII of Part A as well as progress reports on all outstanding compliance schedules submitted pursuant to PCC 17.12.080, and

6. Other facts the Control Officer may require to determine the compliance status of the facility.

B. A copy of all compliance certifications for Class I permits shall also be submitted to the EPA Administrator. The address for the EPA Administrator is:

EPA Region 9 Enforcement Office, 75 Hawthorne St (Air-5), San Francisco, CA 94105

VIII. CERTIFICATION OF TRUTH, ACCURACY AND COMPLETENESS

(PCC 17.12.060.A.3)

Any document required to be submitted by this permit, including reports, shall contain a certification by a responsible official of truth, accuracy, and completeness. This certification and any other certification required by this permit shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

IX. INSPECTION AND ENTRY

(PCC 17.12.060.A.4)

The Permittee shall allow the Control Officer or the authorized representative of the Control Officer upon presentation of proper credentials to:

A. Enter upon the Permittee's premises where a source is located, emissions-related activity is conducted, or where records are required to be kept under the conditions of the permit;

B. Have access to and copy, at reasonable times, any records that are required to be kept under the conditions of the permit;

C. Inspect, at reasonable times, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit;

D. Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with the permit or other applicable requirements; and

E. Record any inspection by use of written, electronic, magnetic and photographic media.

X. PERMIT REVISION PURSUANT TO FEDERAL HAZARDOUS AIR POLLUTANT STANDARD

(PCC 17.12.060.A.5)

If this source becomes subject to a standard promulgated by the Administrator pursuant to Section 112(d) of the Clean Air Act (National Emission Standards for Hazardous Air Pollutants - NESHAP), then the Permittee shall, within twelve months of the date on which the standard is promulgated, submit an application for a permit revision demonstrating how the source will comply with the standard.

XI. EXCESS EMISSIONS, PERMIT DEVIATIONS, AND EMERGENCY REPORTING

A. Excess Emissions Reporting

(PCC 17.12.060.A.6.a)

1. Excess emissions shall be reported as follows:

   a. The Permittee shall report to the Control Officer any emissions in excess of the limits established by this permit. Such report shall be in two parts as specified below:

      i. Notification by telephone, facsimile or e-mail within 24 hours of the time when the Permittee first learned of the occurrence of excess emissions including all available information in condition XI.A.1.b below. The number to call to report excess emissions is 520-724-7400. The facsimile number to report excess emissions is 520-838-7432. The e-mail to report excess emissions is Air.Permits@pima.gov

      ii. Detailed written notification by submission of an excess emissions report within 72 hours of the notification in XI.A.1.a.i above. Notifications should be mailed or e-mailed to:

      PDEQ Air Program 33 N. Stone Avenue, Suite 700, Tucson, Arizona 85701.
      Air.Permits@pima.gov

   b. The report shall contain the following information:

      i. Identity of each stack or other emission point where the excess emission occurred;

      ii. Magnitude of the excess emissions expressed in the units of the applicable emission limitation and the operating data and calculations used in determining the magnitude of the excess emissions;

      iii. Date, time, and duration or expected duration of the excess emissions;

      iv. Identity of the equipment from which the excess emissions emanated;

      v. Nature and cause of the emissions;

      vi. If the excess emissions were the result of a malfunction, steps taken to remedy the malfunction and the steps taken or planned to prevent the recurrence of such malfunctions; and

      vii. The steps that were or are being taken to limit the excess emissions; If the excess emissions resulted from start-up or malfunction, the report shall contain a list of the steps taken to comply with permit procedures.

2. In the case of continuous or recurring excess emissions, the notification requirements of this section shall be satisfied if the source provides the required notification after excess emissions are first detected and includes in such notification an estimate of the time the excess emissions will continue. Excess emissions occurring after the estimated time period or changes in the nature of the emissions as originally reported shall require additional notification pursuant to XI.A.1 above.

B. Permit Deviations Reporting [PCC 17.12.080.A.5.b]

The Permittee shall promptly report deviations from permit requirements, including those attributable to upset conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. Prompt reporting shall mean that the report was submitted to the Control Officer by certified mail, facsimile, e-mail (Air.Permits@pima.gov) or hand delivery within two working days of the time when emission limitations were exceeded due to an emergency or within two working days of the time when the Permittee first learned of the occurrence of a deviation from a permit requirement.

C. Emergency Provision [PCC 17.12.080.A.6]

1. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, that requires immediate corrective action to restore normal operation and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emission attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

2. An emergency constitutes an affirmative defense to an action brought for noncompliance with the technology-based emission limitations if condition XI.C.3 below is met.

3. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

   a. An emergency occurred and that the Permittee can identify the cause or causes of the emergency;

   b. The permitted facility was being properly operated at the time of the emergency;

   c. During the period of the emergency the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards or other requirements in the permit; and

   d. The Permittee submitted notice of the emergency to the Control Officer by certified mail, facsimile, e-mail (Air.Permits@pima.gov) or hand delivery within two working days of the time when emission limitations were exceeded due to the emergency. This notice shall contain a description of the emergency, any steps taken to mitigate emissions, and corrective action taken.

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

5. This provision is in addition to any emergency or upset provision contained in any applicable requirement.

D. Compliance Schedule [ARS § 49-480.F.3 & 5]

For any excess emission or permit deviation that cannot be corrected within 72 hours, the Permittee is required to submit a compliance schedule to the Control Officer within 21 days of such occurrence. The compliance schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with the permit terms or conditions that have been violated.

E. Affirmative Defenses for Excess Emissions Due to Malfunctions, Startup, and Shutdown. [PCC 17.12.080]

1. Applicability

This rule establishes affirmative defenses for certain emissions in excess of an emission standard or limitation and applies to all emission standards or limitations except for standards or limitations:

   a. Promulgated pursuant to Sections 111 or 112 of the Clean Air Act;

   b. Promulgated pursuant to Titles IV or VI of the Clean Air Act;

   c. Contained in any Prevention of Significant Deterioration (PSD) or New Source Review (NSR) permit issued by the U.S. EPA; or

   d. Included in a permit to meet the requirements of PCC 17.16.590.A.5.

2. Affirmative Defense for Malfunctions

Emissions in excess of an applicable emission limitation due to malfunction shall constitute a violation. When emissions in excess of an applicable emission limitation are due to a malfunction, the Permittee has an affirmative defense to a civil or administrative enforcement proceeding based on that violation, other than a judicial action seeking injunctive relief, if the Permittee has complied with the reporting requirements of section XI.A above and has demonstrated all of the following:

   a. The excess emissions resulted from a sudden and unavoidable breakdown of process equipment or air pollution control equipment beyond the reasonable control of the Permittee;

   b. The air pollution control equipment, process equipment, or processes were at all times maintained and operated in a manner consistent with good practice for minimizing emissions;

   c. If repairs were required, the repairs were made in an expeditious fashion when the applicable emission limitations were being exceeded. Off-shift labor and overtime were utilized where practicable to ensure that the repairs were made as expeditiously as possible. If off-shift labor and overtime were not utilized, the Permittee satisfactorily demonstrated that the measures were impracticable;

   d. The amount and duration of the excess emissions (including any bypass operation) were minimized to the maximum extent practicable during periods of such emissions;

   e. All reasonable steps were taken to minimize the impact of the excess emissions on ambient air quality;

   f. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

   g. During the period of excess emissions there were no exceedances of the relevant ambient air quality standards established in PCC Chapter 17.08 that could be attributed to the emitting source;

   h. The excess emissions did not stem from any activity or event that could have been foreseen and avoided, or planned, and could not have been avoided by better operations and maintenance practices;

   i. All emissions monitoring systems were kept in operation if at all practicable; and

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j. The Permittee's actions in response to the excess emissions were documented by contemporaneous records.

3. Affirmative Defense for Startup and Shutdown

a. Except as provided in condition XI.E.3.b above, and unless otherwise provided for in the applicable requirement, emissions in excess of an applicable emission limitation due to startup and shutdown shall constitute a violation. When emissions in excess of an applicable emission limitation are due to startup and shutdown, the Permittee has an affirmative defense to a civil or administrative enforcement proceeding based on that violation, other than a judicial action seeking injunctive relief, if the Permittee has complied with the reporting requirements of XI.A above and has demonstrated all of the following:

i. The excess emissions could not have been prevented through careful and prudent planning and design;

ii. If the excess emissions were the result of a bypass of control equipment, the bypass was unavoidable to prevent loss of life, personal injury, or severe damage to an pollution control equipment, production equipment, or other property;

iii. The source's air pollution control equipment, process equipment, or processes were at all times maintained and operated in a manner consistent with good practice for minimizing emissions;

iv. The amount and duration of the excess emissions (including any bypass operation) were minimized to the maximum extent practicable during periods of such emissions;

v. All reasonable steps were taken to minimize the impact of the excess emissions on ambient air quality;

vi. During the period of excess emissions there were no exceedances of the relevant ambient air quality standards established in PCC Chapter 173.6R that could be attributed to the emitting source;

vii. All emissions monitoring systems were kept in operation if at all practicable; and

viii. Contemporaneous records documented the Permittee's actions in response to the excess emissions.

b. If excess emissions occur due to a malfunction during routine startup and shutdown, then those instances shall be treated as other malfunctions subject to condition XI.E.2 above.

4. Affirmative Defense for Malfunctions during Scheduled Maintenance

If excess emissions occur due to a malfunction during scheduled maintenance, then those instances will be treated as other malfunctions subject to condition XI.E.2 above.

5. Demonstration of Reasonable and Practicable Measures

For an affirmative defense under conditions XI.E.2 or 3 above, the Permittee shall demonstrate, through submission of the data and information required by conditions XI.E.1 – 5 and XI.A of Part A, that all reasonable and practicable measures within the Permittee's control were implemented to prevent the occurrence of the excess emissions.

XII. RECORDKEEPING REQUIREMENTS [PCC 17.12.040.A.4]

A. The Permittee shall keep records of all required monitoring information including but not limited to the following:

1. The date, place as defined in the permit, and time of sampling or measurements;

2. The date(s) analyses were performed;

3. The name of the company or entity that performed the analyses;

4. A description of the analytical techniques or methods used;

5. The results of such analyses; and

6. The operating conditions as existing at the time of sampling or measurement.

B. The Permittee shall retain records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings or other data recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.

C. All required records shall be maintained either in an unchangeable electronic format or in a hardwritten logbook utilizing indelible ink.

XIII. REPORTING REQUIREMENTS [PCC 17.12.040.A.3]

The Permittee shall submit the following reports:

A. Compliance Certification pursuant to section VII above.

B. Excess emission, permit deviation, and emergency reports in accordance with section XI above.

C. Performance test results in accordance with section XVII.G. below.

D. Other reports required by any condition in Part B of this permit.

XIV. DUTY TO PROVIDE INFORMATION [PCC 17.12.040.A.4, PCC 17.12.270.G, & PCC 17.12.730.H]

A. The Permittee shall furnish to the Control Officer, within a reasonable time, any information that the Control Officer may request in writing to determine whether cause exists for revising, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the Permittee shall also furnish to the Control Officer copies of records required to be kept by the permit. For information claimed to be confidential, the Permittee, shall furnish an additional copy of such records directly to the Administrator along with a claim of confidentiality.

B. If the Permittee has failed to submit any relevant facts or has submitted incorrect information in the permit application, the Permittee shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application but prior to release of a proposed permit.

XV. PERMIT AMENDMENT OR REVISION [PCC 17.12.100, PCC 17.12.110 & PCC 17.12.120]

The Permittee shall apply for a permit amendment or revision for changes to the facility which do not qualify for a facility change without revision under section XVI below as follows:

A. Administrative Permit Amendment (PCC 17.12.100);

B. Minor Permit Revision (PCC 17.12.110);

C. Significant Permit Revision (PCC 17.12.120).

The applicability and requirements for such action are defined in the above referenced regulations.

XVI. FACILITY CHANGES ALLOWED WITHOUT PERMIT REVISIONS [PCC 17.12.090]

A. The Permittee may make changes at the permitted source without a permit revision if all of the following apply:

1. The changes are not modifications under any provision of Title I of the Clean Air Act (Air Pollution Prevention and Control) or under modifications as defined in A.R.S. 49-401.01;

2. The changes do not exceed the emissions allowable under the permit whether expressed therein as a rate of emissions or in terms of total emissions;

3. The changes do not violate any applicable requirements or trigger any additional applicable requirements;

4. The changes satisfy all requirements for a minor permit revision under PCC 17.12.110; and

5. The changes do not contravene federally enforceable permit terms and conditions that are monitoring (including test methods), record keeping, reporting, or compliance certification requirements.

B. The substitution of an item of process or pollution control equipment for an identical or substantially similar item of process or pollution control equipment shall qualify as a change that does not require a permit revision, if it meets all of the requirements of conditions XVI.A, D and E below.

C. Except for sources with authority to operate under general permits, permitted sources may trade increases and decreases in emissions within the permitted facility, as established in the permit under PCC 17.12.040.A.12 if an applicable implementation plan provides for the emissions trades, without applying for a permit revision and based on the seven working days' notice prescribed in section XVI.D below. This provision is available if the permit does not provide for the emissions trading as a minor permit revision.

D. For each change under conditions XVI.A through C above, a written notice, by certified mail or hand delivery, shall be received by the Control Officer and the Administrator a minimum of seven (7) working days in advance of the change. Notifications of changes associated with emergency conditions, such as malfunctions necessitating the replacement of equipment, may be provided less than 7 working days in advance of the change but must be provided as far in advance of the change, or if advance notification is not practicable as soon after the change as possible.

E. Each notification shall include:

1. When the proposed change will occur;
2. A description of the change;
3. Any change in emissions of regulated air pollutants;
4. The pollutants emitted subject to the emissions trade, if any;
5. The provisions in the implementation plan that provide for the emissions trade with which the source will comply and any other information as may be required by the provisions in the implementation plan authorizing the trade;
6. If the emissions trading provisions of the implementation plan are invoked, then the permit requirements with which the source will comply; and
7. Any permit term or condition that is no longer applicable as a result of the change.

F. The permit shield described in Condition XX shall not apply to any change made under this section. Compliance with the permit requirements that the source will meet using the emissions trade shall be determined according to requirements of the implementation plan authorizing the emissions trade.

G. Except as otherwise provided for in the permit, making a change from one alternative operating scenario to another as provided under PCC 17.12.040.A.11 shall not require any prior notice under this section..

H. Notwithstanding any other part of this section, the Control Officer may require a permit to be revised for any change that when considered together with any other changes submitted by the same source under the provisions of this condition over the term of the permit, do not satisfy the conditions in XVI.A above.

XVII. TESTING REQUIREMENTS [PCC 17.12.230]

A. New sources required to conduct performance testing shall do so within 60 days after the source has achieved the capability to operate at its maximum production rate on a sustained basis but no later than 180 days after initial startup of such sources. The Permittee shall conduct performance testing as specified in Part B of the permit and at such other times as may be required by the Control Officer. The Permittee shall furnish the control officer a written report or the results of the tests.

B. Operational Conditions During Testing

Performance tests shall be conducted while the unit is operating at full load under representative operational conditions unless other conditions are required by the applicable test method or in this permit. With prior written approval from the Control Officer, testing may be performed at a lower rate. Operations during start-up, shutdown, and malfunction (as defined in PCC 17.04.340.A) shall not constitute representative operational conditions unless otherwise specified in the applicable requirement.

C. Tests shall be conducted and data reduced in accordance with the test methods and procedures contained in the Arizona Testing Manual, 40 CFR 52; Appendices D and E, 40 CFR 60; Appendices A through F, and 40 CFR 61, Appendices B and C unless modified by the Control Officer pursuant to PCC 17.11.210.B or by the Director pursuant to A.A.C. R18-2-312.B.

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D. Test Plan

At least 14 calendar days prior to performing a test, the Permittee shall submit a test plan to the Control Officer, in accordance with PCC 17.11.210.D and the Arizona Testing Manual. This test plan must include the test duration, test location(s), test methods, and source operation and other parameters that may affect the test results.

E. Stack Sampling Facilities

The Permittee shall provide or cause to be provided, performance testing facilities as follows:

1. Sampling ports adequate for test methods applicable to the facility;

2. Safe sampling platform(s);

3. Safe access to sampling platform(s); and,

4. Utilities for sampling and testing equipment

F. Interpretation of Final Results

Each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic mean of the results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs is required to be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the Permittee's control, compliance may, upon the Control Officer's approval, be determined using the arithmetic mean of the results of the other two runs. If the Control Officer or the Control Officer's designee is present, tests may only be stopped with the Control Officer's or such designee's approval. If the Control Officer or the Control Officer's designee is not present, tests may only be stopped for good cause. Good cause includes: forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the Permittee's control. Termination of any test without good cause after the first run is commenced shall constitute a failure of the test. Supporting documentation, which demonstrates good cause, must be submitted.

G. Report of Final Test Results

A written report of the results of all performance tests shall be submitted to the Control Officer within 30 days after the test is performed. The report shall be submitted in accordance with the Arizona Testing Manual and PCC 17.11.210.A.

XVIII. PROPERTY RIGHTS [PCC 17.12 Part A.8.g]

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

XIX. SEVERABILITY CLAUSE [PCC 17.12 Part A.5]

The provisions of this permit are severable. In the event of a challenge to any portion of this permit, or if any portion of this permit is held invalid, the remaining permit conditions remain valid and in force.

XX. PERMIT SHIELD [PCC 17.12 Part A.8.e]

Compliance with the conditions of this permit shall be deemed compliance with any applicable requirement identified in the permit as of the date of permit issuance, provided that such applicable requirements are included and expressly identified in the permit. The permit shield shall not apply to any change made pursuant to conditions XV.B and XVI above.

XXI. ACCIDENT PREVENTION REQUIREMENTS UNDER THE CLEAN AIR ACT (CAA Section 112(r))

Should this stationary source, as defined in 40 CFR Part 68.3, become subject to the accidental release prevention regulations in Part 68, then the Permittee shall submit a risk management plan (RMP) by the date specified in Section 68.10 and shall certify compliance with the requirements of Part 68 as part of the annual compliance certification as required by 40 CFR Part 70 and Part B of this permit.

XXII. ASBESTOS REQUIREMENTS (Demolition/ Renovation)

Should this stationary source, pursuant to 40 CFR 61, Subpart M become subject to the National Emission Standards for Hazardous Air Pollutants - Asbestos regulations when conducting any renovation or demolition at this premises, then the Permittee shall submit proper notification as described in 40 CFR Subpart M and shall comply with all other applicable requirements of subpart M. The Permittee shall keep a record of all relevant paperwork on file. [40 CFR 61, Subpart M]

XXIII. STRATOSPHERIC OZONE DEFLETING SUBSTANCES

The Permittee shall not use, sell, or offer for sale any fluid as a substitute material for use in any motor vehicle, residential, commercial, or industrial air conditioning system, refrigerator or freezer unit, or other cooling or heating device designed to use a chlorofluorocarbon (CFC) or hydrochlorofluorocarbon (HCFC) compound as a working fluid, unless such fluid has been approved for sale and such use by the Administrator. The Permittee shall keep a record of all paperwork relevant to the applicable requirements of 40 CFR 82, Subpart F onsite. [40 CFR 82 & PCC 17.16.230]

PART B: SPECIFIC CONDITIONS

All standards are Federally Enforceable unless otherwise noted
[References are to Title 17 of the Pima County Code unless otherwise noted]

I. FACILITY GENERAL PROVISIONS

A. Statutory Authority [PCC 17.81.010.D & PCC 17.12.130, & SIP Rule 301]

Emissions from this facility, specifically the emissions from the equipment described in Attachment 2 of this permit, fall under primary SIC Code 4911 and are subject to enforceable limitations as provided in the Specific Conditions in this permit. This permit is issued pursuant to (ARS) §49-480 and authorizes the construction and/or operation of the equipment enumerated in the "Equipment List" in Attachment 2. This authorization is based on the regulations in effect on the date of issuance of this permit, and a finding that the allowable emissions from this facility constitute an existing "major source" within the meaning of PCC 17.04.340.A.128. Notwithstanding the above findings, the issuance of this air quality permit shall not relieve the Permittee from compliance with all local, county, state and federal air quality laws, statutes, and codes. [PCC 17.81.010.B & D, PCC 17.12.010 and ARS §49-480]

B. Permit Classification [PCC 17.81.090]

Class I; Major Source; Stationary: The permitted facility sources constitute a major source of all criteria pollutants except lead (Pb), and a major source of combined HAPs based on the equipment capacity, fuel limitations, and emission limitations contained in this permit and when considering the emissions from sources aggregated under the same primary SIC Code at this facility.

C. Permitted Facility Sources

The Specific Conditions contained in this permit apply to the equipment listed in Attachment 2 of this permit and the following source categories:

a. Electric Utility Steam Generating Units "EGU's
b. Cooling Towers
c. Stationary Rotating Machinery
d. Emergency Generators – Local Requirements
e. NESHAP Subpart ZZZZ Requirements
f. NSPS Subpart IIII Requirements
g. Nonpoint Fugitive Dust Sources
h. Use of Paints
i. Abrasive Blasting
j. Reciprocating Internal Combustion Engine (RICE)

D. Compliance Certification Reporting

The Permittee shall submit annual compliance certification reports to the Control Officer and EPA Administrator pursuant to section VII of Part A. Annual compliance certification reports shall be due on February 15th of each year and shall cover the period January 1st through December 31st. [40 CFR 70.6(c)(5) & PCC 17.12.090.A.2]

E. Semiannual Summary Reports of Required Monitoring

The Permittee shall submit a semiannual summary report of all permit deviations and exceedances that have occurred during the reporting period. Semiannual reports shall be due on January 31st and July 31st of each year and shall cover the period July 1st through December 31st and January 1st through June 30th, respectively. The first semiannual report may not cover a six-month period. If there are no deviations, excursions, or exceedances in a reporting period, no report shall be required. [40 CFR 70.6(c)(5) & PCC 17.12.040.A.5.a]

F. Opacity Limits [Federally Enforceable when opacity is greater than 40%]

1. The opacity of an emission from nonpoint sources shall not exceed 20% as measured in accordance with the Arizona Test Manual and EPA Reference Method 9 in 40 CFR Part 60, Appendix A. For purposes of this condition, a nonpoint source is any source of air contaminants which due to a lack of an identifiable emission point or plume cannot be considered a point source. [PCC 17.16.030.B. & SIP Rule 321]

2. The opacity of all plumes and effluents from a single emission point, multiple emission point, or fugitive emission sources shall not equal or exceed an average optical density equal to or greater than 20%, except as otherwise specified in the Specific Conditions of this permit and the table in Attachment 4 subject to the following provisions: [PCC 17.16.030, PCC 17.16.130.B.3, & SIP Rule 321, Installation Permit # 1156, Condition #5]

   a. Opacities (optical densities), as measured in accordance with Method 9, of an effluent shall be measured by a certified visible emissions evaluator with his natural eyes, approximately following the procedures which were used during his certification, or by an approved and precisely calibrated in-stack monitoring instrument. [PCC 17.16.030, & SIP Rule 321, Installation Permit # 1156, Condition #5]

   b. A violation of an opacity standard shall be determined by measuring and recording a set of consecutive, instantaneous opacities, and calculating the arithmetic average of the measurements within the set unless otherwise noted in this permit. The measurements shall be made at approximately fifteen-second intervals for a period of at least six minutes, and the number of required measurements shall be as specified in Attachment 4. Sets need not be consecutive in time, and in no case shall two sets overlap. If the average opacity of the set of instantaneous measurements exceeds the maximum allowed by any rule, this shall constitute a violation.

   c. The use of air or other gaseous diluents solely for the purpose of achieving compliance with an opacity standard is prohibited. [PCC 17.16.040.A.3 & SIP Rule 321]

   d. When the presence of uncombined water is the only reason for failure of a source to otherwise meet the requirements as specified in conditions I.F and I.E, conditions I.F and I.E shall not apply. [PCC 17.16.040.B & SIP Rule 321]

3. Unless otherwise required by the Specific Conditions in this permit, a demonstration to show compliance with the emission limitations for opacity in equipment listed in Attachment 2 of this permit when combusting natural gas and/or landfill gas shall not be required since the percent of opacity of visible emissions while combusting gaseous fuels is inherently low.

G. Visibility Limiting Standard

1. The Permittee shall not cause, suffer, allow, or permit diffusion of visible emissions, including fugitive dust, beyond the property boundary line within which the emissions become airborne, without taking reasonably necessary and feasible precautions to control generation of airborne particulate matter. Sources may be required to cease temporarily the activity or operation which is causing or contributing to the emissions until reasonably necessary and feasible precautions are taken. This condition shall not apply to the generation of airborne particulate matter from undisturbed land. [PCC 17.16.030.D & SIP Rule 343]

2. I.G.2 of this section shall not apply when wind speeds exceed twenty-five (25) miles per hour (using the Beaufort Scale of Wind-Speed Equivalents, or as recorded by the National Weather Service). This exception does not apply if control measures have not been taken or were not commensurate with the size or scope of the emission source. [PCC 17.16.030.D & SIP Rule 343]

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3. The Permittee shall not cause, suffer, allow or permit operations or activities likely to result in excessive amounts of airborne dust without taking reasonable precautions to prevent excessive amounts of particulate matter from becoming airborne. [PCC 17.16.030 A]

[Locally Enforceable Condition]

H. Odor Limiting Standard

The Permittee shall not emit gaseous or odorous materials from equipment, operations, or premises in such quantities or concentrations to cause air pollution. [PCC 17.16.040 & SIP Rule 301]

I. General Control Standards

1. The Permittee shall not commence construction of a new major source or the major modification of a source covered by this permit without first obtaining a permit or permit revision from the Control Officer. [PCC 17.16.550 & SIP Rule 301]

2. The Permittee shall not cause or permit the planning, construction, installation, erection, modification, use, or operation of an emission source which will cause or contribute to a violation of an applicable performance standard. [PCC 17.16.070 & SIP Rule 301]

3. Where a stack, vent or other outlet is at such a level that fumes, gas mist, odor, smoke, vapor or any combination thereof constituting air pollution are discharged to adjoining property, the Control Officer may require the installation of abatement equipment or the alteration of such stack, vent or other outlet by the owner or operator thereof to a degree that will adequately reduce or eliminate the discharge of air pollution to adjoining property. [PCC 17.16.030 B]

[Locally Enforceable Condition]

J. General Materials Handling Standards **[Locally Enforceable Conditions]**

1. The Permittee shall not transport or store VOC's without taking necessary and feasible measures to control evaporation, leakage, or other discharge into the atmosphere. [PCC 17.16.040 A]

2. Materials including solvents or other volatile compounds, paints, acids, alkalies, pesticides, fertilizers and manure shall be processed, stored, used and transported in such a manner and by such means that they will not evaporate, leak, escape or be otherwise discharged into the ambient air so as to cause or contribute to air pollution. Where means are available to reduce effectively the contribution to air pollution from evaporation, leakage or discharge, the installation and use of such control methods, devices, or equipment shall be mandatory. [PCC 17.16.040 B]

K. Definition of Heat Input

For purposes of sections II through IV of this Part, the heat input shall be the aggregate heat content of all fuels whose products of combustion pass through a stack or other outlet. [PCC 17.16.100 A & PCC 17.16.110 A]

[Locally Enforceable Condition]

L. Fuel Sulfur Limitations

Except as otherwise specified in the Specific Conditions of this permit, the Permittee shall be considered in compliance with the fuel sulfur limitations in this permit by demonstrating that only the specified fuel allowed was fired in the applicable equipment. Such a demonstration may be made by making available to the Control Officer for his inspection, documentation, such as invoices or statements from the fuel supplier, or sample analysis which verify the sulfur content of the fuel being piped and/or delivered. [PCC 17.12.030 A.3.c]

[Locally Enforceable Condition]

M. Applicability of More Than One Standard

If more than one emission limit or emission standard in this permit is applicable to the same source, the more stringent standard or emission limit shall apply. [PCC 17.16.030 B]

[Locally Enforceable Condition]

N. Authorization to Construct and Conditional Authorization to Operate Modifications to RICE

1. This significant revision to the Class I, Title V air quality permit is an authorization to construct a major modification, i.e., to install up to ten reciprocating internal combustion engines (Units RICE01-RICE10) and ancillary equipment as set forth in Specific Conditions II.A through II.D below.

2. The stack for each RICE must be configured into two groups of five (ten stacks in total) clustered stacks. Within each group of five there are two clusters, one of three stacks and one of two stacks each separated by slightly less than one diameter (outside edge to outside edge) from the other stack(s) in the cluster for a total of four clusters in two groups. [40 CFR 63.7788]

O. Compliance Assurance Monitoring Plan [40 CFR 64.2]

1. Compliance Assurance Monitoring (CAM) is applicable to the RICE for CO emissions. CAM requires monitoring, compliance certification, periodic reporting, and recordkeeping information collections by the Permittee because the RICE pre-control potential to emit CO exceeds the major source threshold. A CAM plan is required to provide a reasonable assurance of compliance with the applicable requirements (e.g. CO emission limits) for the emission units that rely on control device equipment to achieve compliance (the RICE).

2. CAM Operational Standards

   a. The Permittee shall prepare and submit a CAM Plan to the Department for review within 30 days of issuance of this Permit.

   b. The Plan will include monitoring the oxidation catalyst for the following parameters, at a minimum:

      (1). Temperature at the inlet to the oxidation catalyst

      (2). Pressure drop across the oxidation catalyst

      (3). Monitoring shall be conducted continuously at all times that the RICE are operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part. The Permittee shall use the data collected during all other periods in assessing the operation of the control device. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. [40 CFR 64.7(d)]

3. Response to Excursions or Exceedances

   a. Upon detecting an excursion or exceedance, the Permittee shall restore operation of the RICE (including the control device) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown, or malfunction, and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action, or any necessary follow-up actions to return operations to within the indicator range, designated condition, or below the emission limitation or standard, as applicable. [40 CFR 64.7(d)(1)]

   b. Determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process. [40 CFR 64.7(d)(2)]

4. Approved Monitoring and Compliance Schedule

   a. To provide a reasonable assurance of compliance with emission limitations or standards for the anticipated range of operations at a pollutant-specific emissions unit, the approved CAM plan document shall include monitoring criteria that satisfies 40 CFR 64.3 and 40 CFR 64.4. The Permittee shall submit monitoring 90 days after issuance of this permit, but in no case shall the Permittee submit revised monitoring more than 180 days from the date of issuance of the draft or final permit. [40 CFR 64.3, 40 CFR 60.4, 40 CFR 64.6(c)(2) and PCC 17.12.190.A]

   b. If the Permittee does not submit the monitoring in accordance with the compliance schedule as required in I.O.4 of this Section or if the Control Officer disapproves the monitoring submitted, the source owner or operator shall be deemed not in compliance with 40 CFR Part 64, unless the Permittee successfully challenges the disapproval. [40 CFR 64.6(c)(3)]

5. Documentation of Need for Improved Monitoring.

   After approval of monitoring under this part, if the Permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the Control Officer and, if necessary, submit a proposed modification to the part 70 or 71 permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. [40 CFR 64.7(e)]

6. Reporting and Recordkeeping Requirements

   Excursions shall be reported as required by Condition VII.A.1 of Part "A" of this permit. The report shall include, at a minimum, the following: [PCC 17.12.220.A.c.i] [Locally Enforceable Condition]

   a. Summary information on the number, duration and cause (including unknown cause, if applicable) of excursion or exceedances, as applicable, and the corrective actions taken; and [40 CFR 64.9(a)(2)(i)]

   b. Summary information on the number, duration and cause (including unknown cause, if applicable) for monitoring downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable). [40 CFR 64.9(a)(2)(ii)]

7. Minimum data availability requirement

   The Permittee is provided a 95% daily reading recordkeeping deviation allowance, which allows for up to 2 missed readings per month. [40 CFR 64.6(c)(4)]

II. RECIPROCATING INTERNAL COMBUSTION ENGINES (RICE), PSD AND BEST AVAILABLE CONTROL TECHNOLOGY (BACT) REQUIREMENTS

The conditions in this section apply to the RICE Units (RICE01, RICE02, RICE03, RICE04, RICE05, RICE06, RICE07, RICE08, RICE09, and RICE10).

A. Rice PSD and Best Available Control Technology (BACT) Emission Limits and Standards

1. Nitrogen Oxides (NO_X) Emissions Cap [PCC 17.12.050]

   a. The combined total NO_X from emissions units RICE01 through RICE10 shall not exceed 170.0 tons per year (tpy), based on a 12-month rolling total, calculated monthly.

   b. Compliance with the NO_X emission limit shall be demonstrated by performance tests as detailed in Condition II.D, monitoring as detailed in Condition II.B., and recordkeeping as detailed in Conditions II.C.

   c. The permittee shall equip each RICE with an SCR system. The SCR system shall be operated at all times while fuel is flowing to the RICE, excluding periods of startup. The SCR system shall be maintained and operated in a manner consistent with good air pollution control practice for minimizing NO_X emissions. Good engineering practices shall include the following:

      i. The catalyst shall be cleaned and/or replaced in accordance with manufacturer recommendations.

      ii. Routine maintenance and inspections shall be conducted in accordance with manufacturer recommendations.

      iii. If the ammonia injection fails at any time, the permittee shall conduct an investigation of the SCR system. If the ammonia injection cannot be restored within 10 minutes, the RICE shall be shut down.

      iv. Each SCR system shall be equipped with a continuous NO_X process monitor capable of measuring and recording the NO_X concentration in the SCR outlet gases.

2. Volatile Organic Compounds (VOC) Limit [40 CFR §52.21(j)(3)]

   a. VOC emissions from each emissions unit (RICE01 through RICE10) shall not exceed 4.49 pounds per hour (lbs/hr), excluding periods of startup.

   b. The permittee shall equip each RICE with an oxidation catalyst system. The oxidation catalyst system shall be operated at all times while fuel is flowing to the RICE, including periods of startup, shutdown, and malfunction. The oxidation catalyst system shall be maintained and operated in a manner consistent with good air pollution control practice for minimizing VOC emissions. Good engineering practices shall include the following:

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i. The catalyst shall be cleaned and/or replaced in accordance with manufacturer recommendations.

ii. Routine maintenance and inspections shall be conducted in accordance with manufacturer recommendations.

c. Compliance with this limit shall be demonstrated by a performance test as detailed in Condition II.D.3.

3. Carbon Monoxide (CO) Limit [40 CFR §52.21(j)(2)]

a. CO emissions from each emissions unit (RICE01 through RICE10) shall not exceed 4.43 lbs/hr, excluding periods of startup.

b. The permittee shall equip each RICE with an oxidation catalyst system. The oxidation catalyst system shall be operated at all times while fuel is flowing to the RICE, including periods of startup, shutdown, and malfunction. The oxidation catalyst system shall be maintained and operated in a manner consistent with good air pollution control practice for minimizing CO emissions. Good engineering practices shall include the following:

i. The catalyst shall be cleaned and/or replaced in accordance with manufacturer recommendations.

ii. Routine maintenance and inspections shall be conducted in accordance with manufacturer recommendations.

c. Compliance with this limit shall be demonstrated by a performance test as detailed in Condition II.D.4.

4. Particulate Matter ($PM_{10}/PM_{2.5}$) Limit [40 CFR §52.21(j)(2)]

a. $PM_{10}/PM_{2.5}$ emissions from each emission unit (RICE01 through RICE10) shall not exceed 2.37 lb/hr, excluding periods of startup.

b. Compliance with this limit shall be demonstrated by a performance test as detailed in Condition II.D.5.

5. For emissions units RICE01 through RICE10, during periods of startup, the permittee shall minimize the engine's time spent at idle and shall minimize the startup time to a period needed for appropriate and safe loading of the engine. Startup shall not exceed 30 minutes in duration. After 30 minutes of operation, the non-startup emission limitations for CO, VOC, and PM10/PM2.5 applies. [40 CFR §§52.21(j)(3) & 52.210(a)]

6. The total number of startups per calendar day for each RICE shall not exceed 5. [40 CFR §§52.21(j)(3), 52.210(a)]

7. The permittee shall, at all times, operate and maintain each RICE, including associated air pollution control equipment (oxidation catalysts and SCRs) and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. [40 CFR §§52.21(j)(3) & (t), 52.210(a)]

8. Greenhouse Gases (GHG) Limit [40 CFR §52.21(j)(3)]

a. CO_2 emissions from each emissions unit (RICE01 through RICE10) shall not exceed 1,100 lbs/MWh of gross electric output based on a 12-month rolling average, calculated monthly.

b. Compliance with this limit shall be demonstrated by monitoring as detailed in Condition II.E.8 and recordkeeping as detailed in Condition II.C.12.

9. Greenhouse Gases (GHG) BACT Equipment Design Standard for sulfur hexafluoride (SF_6)-Containing Circuit Breakers [40 CFR §52.21(j)(3)]

a. The permittee shall install and operate only enclosed SF_6-containing high-voltage circuit breakers having a vendor-guaranteed leak rate of 0.5 percent or less per year.

b. The permittee shall implement a density monitor alarm system with a threshold of 10 percent or less. In the event of an alarm, the permittee shall investigate the event and take any necessary corrective action to address problems. Compliance with this requirement shall be demonstrated by recordkeeping as detailed in Condition II.C.9.

10. Greenhouse Gases (GHG) BACT Work Practice Requirement for Natural Gas Piping [40 CFR §52.21(j)(3)]

a. The permittee shall implement an audio/visual/olfactory method for detecting leaking from natural gas piping components which shall involve making observations on no less than a daily basis.

b. Compliance with this requirement shall be demonstrated by recordkeeping as detailed in Condition II.C.13.

11. Fuel Sulfur Content [PSD-OR-1062-99A.1(c)]

The maximum sulfur content in the pipeline quality natural gas is 7,500 grains per million cubic feet or less. Documentation shall be maintained that the sulfur content in the natural gas delivered does not exceed this sulfur content.

E. PSD AND BACT Monitoring Requirements [40 CFR §52.21(j)(3)]

1. Each emissions unit (RICE01 through RICE10) shall be equipped with a monitoring system capable of measuring and recording the hours of operation (in tenths of an hour) and natural gas consumption (in millions of British thermal units [MMBtu]).

2. Startup is defined as setting in operation any air pollution source for any purpose. Startup begins when fuel is first combusted in the engine and ends when the generator output is 4.75 MW (25% of net-rated capacity) or more and the temperature at the outlet of the SCR is 536 degrees Fahrenheit (°F) or more. The duration of startup shall be monitored and recorded.

3. The following parameters shall be monitored for each SCR when the associated RICE is operational:

a. The ammonia injection rate to the SCR system shall be monitored continuously.

b. The temperature at the outlet of the SCR. The SCR is not considered operational until the temperature at the outlet of the SCR exceeds 536°F.

4. The following parameters shall be monitored for each oxidation catalyst when the associated RICE is operational:

a. The pressure drop and temperature across the oxidation catalyst shall be monitored continuously.

5. Each emissions unit (RICE01 through RICE10) shall be equipped with a station grade watt-hour meter for monitoring the gross electrical power output of the associated generator.

C. PSD AND BACT Recordkeeping and Reporting Requirements

1. For each hour (or tenth of an hour), the RICE operation shall be recorded as startup or operating. For any startup event, the duration of the startup event shall be recorded. [40 CFR §52.21(j)(3)]

2. The Permittee shall document that the associated SCR and oxidation catalyst are operable prior to starting each RICE. [40 CFR §52.21(j)(3)]

3. The number of startups per RICE unit shall be recorded daily. [40 CFR §52.21(j)(3)& PCC 17.12.050]

4. The following parameters shall be recorded for each SCR when the associated RICE is operational: [PCC 17.12.050]
   a. The ammonia injection rate to the SCR system shall be recorded at least once every 15 minutes.
   b. The temperature at the outlet to the SCR shall be recorded at least once every 15 minutes.
   c. Records shall be kept of any event in which the ammonia injection fails for more than two minutes at any time while the RICE is operating, excluding periods of startup.

5. The following parameters shall be recorded for each oxidation catalyst when the associated RICE is operational; [40 CFR §52.21(j)(3)]
   a. The pressure drop across the oxidation catalyst and the temperature at the inlet to the oxidation catalyst shall be recorded at least once every 15 minutes.

6. The following parameters shall be recorded for each SCR when the associated RICE is operational: [PCC 17.12.050]
   a. The Permittee shall maintain records of the catalyst cleaning, replacement, or reconditioning.
   b. The Permittee shall maintain records of the operation and maintenance (O&M) procedures, maintenance schedules, and records of inspections and maintenance onsite.

7. The gross electrical power output of the associated generator for each emissions unit (RICE01 through RICE10) shall be recorded hourly during every hour of operation, including startup. [40 CFR §52.21(j)(3)]

8. For circuit breakers, the permittee shall document alarm events and corrective actions. The Permittee shall notify PDEQ within 7 days of alarm events. The notification shall include the planned corrective action, estimated timeframe for completion, and an estimate of emissions. Within 7 days of completion of corrective actions, the Permittee shall notify PDEQ of the completion of the corrective actions, including the corrective action taken, the calculated emissions, and the date of completion of the corrective action. [40 CFR §52.21(j)(2)]

9. On a monthly basis, for each RICE, the permittee shall calculate and record NO_X emissions using the monthly records of heat input during periods other than startup, the NO_X emission factor for non-startup periods as determined during the most recent emission test for that RICE, the number of startup events during the month, and the vendor specified NO_X cold startup emission rate for each startup event (see equation below).

   A = [Total heat input (BTU/month) - Heat input during periods of startup (BTU/month)] X [NO_X emission factor (lbs NOx/BTU)]

   B = [Number of startup events per month (Startups/month)] X [Cold startup NO_X emission factor (lbs NO_X/Startup)]

   NO_X Emissions = A + B pounds of NO_X emitted per month (lbs NO_X/month) [PCC 17.12.050]

10. On a monthly basis, the permittee shall calculate and record total NO_X emissions for the ten RICE, both for the most recent month and as a 12-month rolling total calculated using data from the most recent month and the eleven immediately preceding months. [PCC 17.12.050]

11. On a monthly basis, for each RICE and its associated generator, the permittee shall calculate and record GHG emissions in pounds, using the monthly total heat input records and the applicable GHG emission calculation procedures in 40 CFR part 98, and in lbs/MWh, using the monitoring data from the associated watt-hour meter. [40 CFR §52.21(j)(3)]

12. The permittee shall record any leaks detected in natural gas piping components, and any corrective actions taken, no less frequently than daily. [40 CFR §52.21(j)(3)]

D. PSD AND BACT Testing Requirements

1. Performance tests to demonstrate compliance with the NO_X, VOC, CO, and PM10/PM2.5 emission limitations shall be conducted annually, in accordance with the following schedule. Each RICE shall be subjected to a performance test within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup. Thereafter, testing shall be conducted annually according to the following schedule: The Permittee shall conduct performance tests of at least five RICE in each calendar year, and each RICE shall be subjected to a performance test no less frequently than once in each period of two consecutive calendar years.

2. Nitrogen Oxides (NO_X)
   a. The permittee shall perform NO_X emissions testing of each RICE using the methods and procedures in 40 CFR § 60.4244 and Table 2 of 40 CFR part 60, subpart JJJJ.
   b. Tests shall be performed at 25, 40, 70, and 100 percent of peak load or at a minimum and peak load capacity in the normal operating range of the engine, based upon the past twelve months of operation.
   c. The Permittee shall establish a NO_X emission factor for non-startup periods expressed in lb/MMBtu heat input using the results of the most recent NO_X emissions test approved by PDEQ. The emission factor for each RICE shall be set as the maximum lb/MMBtu emission factor observed during testing of such RICE under any load conditions.

3. Volatile Organic Compounds (VOC)
   a. The permittee shall measure the emission rate of VOC at the exhaust of the engines (RICE01 through RICE10) using US EPA Method 25A. US EPA Method 18 may be used in conjunction with US EPA Method 25A in order to quantify methane and ethane emissions.
   b. Tests shall be performed at 25, 40, 70, and 100 percent of peak load or at a minimum and peak load capacity in the normal operating range of the engine, based upon the past twelve months of operation.
   c. For emission inventory purposes, the Permittee shall establish a VOC emission factor for non-startup periods expressed in lb/MMBTU heat input using the results of the most recent VOC emissions test approved by PDEQ. The emission factor for each RICE shall be set as the maximum lb/MMBtu emission factor observed during testing of such RICE under any load conditions.

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4. Carbon Monoxide (CO)

a. The permittee shall measure the emission rate of CO at the exhaust of the engines (RICE01 through RICE10) using US EPA Method 10.

b. Tests shall be performed at 25, 40, 70, and 100 percent of peak load or at a minimum and peak load capacity in the normal operating range of the engine, based upon the past twelve months of operation.

c. For emission inventory purposes, the Permittee shall establish a CO emission factor for non-startup periods expressed in lb/MMBTU heat input using the results of the most recent CO emissions test approved by PDEQ. The emission factor for each RICE shall be set as the maximum lb/MMBtu emission factor observed during testing of such RICE under any load conditions.

5. Particulate Matter (PM10/PM2.5)

a. The permittee shall measure the emission rate of filterable and condensable particulate matter at the exhaust of the engines (RICE01 through RICE10) using EPA Method 5 and US EPA Method 202.

b. Tests shall be performed at 25, 40, 70, and 100 percent of peak load or at a minimum and peak load capacity in the normal operating range of the engine, based upon the past twelve months of operation.

c. Each test run shall be a minimum of 120 minutes with a minimum sample volume of 90 dry standard cubic feet (dscf).

d. For emission inventory purposes, the Permittee shall establish a PM10/PM2.5 emission factor for non-startup periods expressed in lb/MMBTU heat input using the results of the most recent PM10/PM2.5 emissions test approved by PDEQ. The emission factor for each RICE shall be set as the maximum lb/MMBtu emission factor observed during testing of such RICE under any load conditions.

6. A report of the results of the performance tests shall be submitted to the Department within 30 days after the test is performed in accordance with Part A Condition XVII.

7. Alternative test methods may be used with prior written approval from the Department.

III. RECIPROCATING INTERNAL COMBUSTION ENGINES, UNITS RICE01-RICE10 – NSPS SUBPART JJJJ REQUIREMENTS

The conditions in this section apply to the reciprocating internal combustion engines – Units RICE01-RICE10 listed in Table VI, Attachment 2. The units are 18-cylinder, four-stroke, lean-burn spark ignition (SI) RICE fueled by pipeline natural gas, with a nominal mechanical output capacity of 26,820 horsepower (HP).

A. Emissions Limits and Standards

The permittee shall comply with the applicable emission standards in Table 1 of subpart JJJJ. Pursuant to 40 CFR § 60.4234, these emission standards apply over the entire life of the RICE. Because each RICE to be installed at the IGS is a natural gas fueled, non emergency SI RICE with a maximum engine power ≥ 500 HP and with a manufacture date after July 1, 2010, the applicable standards in Subpart JJJJ, Table 1 are as follows:

1. The permittee must not cause to be discharged into the atmosphere from emissions units RICE01 through RICE10 any gases which contain NO_x in excess of 1.0 gram per horsepower-hour (g/HP-hr) brake work of the engine.

2. The permittee must not cause to be discharged into the atmosphere from emissions units RICE01 through RICE10 any gases which contain CO in excess of 2.0 g/HP-hr brake work of the engine.

3. The permittee must not cause to be discharged into the atmosphere from emissions units RICE01 through RICE10 any gases which contain VOC in excess of 0.7 g/HP-hr brake work of the engine, excluding formaldehyde. [40 CFR § 60.4233(e)]

B. Compliance Demonstration Requirements

The permittee shall comply with one of the following three options for demonstrating compliance with the emission standards in Specific Conditions III.A.1-3:

[40 CFR § 60.4243(a)]

1. Purchase an engine certified according to procedures specified in Subpart JJJJ, for the same model year, operate and maintain the engine and control device according to the manufacturer's emission-related written instructions, and keep records of conducted maintenance.

[40 CFR § 60.4243(a)(1) and (b)(1)]

2. Purchase an engine certified according to procedures specified in Subpart JJJJ, for the same model year, keep a maintenance plan and records of conducted maintenance, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions, conduct an initial performance test within 1 year of engine startup and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter.

[40 CFR § 60.4243(a)(2) and (b)(2)(i) and (ii)]

3. Purchase a non-certified engine, keep a maintenance plan and records of conducted maintenance, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions, conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter.

[40 CFR § 60.4243(a)(2) and (b)(2)(i) and (iii)]

C. Recordkeeping and Reporting Requirements

1. The permittee shall maintain records of all notifications submitted to comply with 40 CFR 60 Subpart JJJJ, records of all documentation supporting any such notifications, and records of maintenance conducted on the engine. [40 CFR § 60.4245(a)(1) and (a)(2)]

2. If the permittee elects to comply with the emission standards in this section by purchasing a certified engine, the permittee shall maintain records of documentation from the manufacturer that the engine is certified to meet the applicable emission standards.

[40 CFR § 60.4245(a)(3)]

3. If the permittee elects to comply with the emission standards in this section through performance testing, the permittee shall:

a. Maintain records of documentation that the engine meets the applicable emission standards in Table 1 of Subpart JJJJ [40 CFR § 60.4245(a)(4)]

b. Submit written notification of the date construction of an affected facility is commenced postmarked no later than 30 days after such date.

c. Submit an initial notification that includes: the name and address of the owner or operator; the address of the affected source; engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement; emission control equipment; and fuel used [40 CFR § 60.7(a)(1)]

d. Submit a copy of each performance test within 60 days after the test has been completed. [40 CFR § 60.4244]

e. Provide performance testing facilities, conduct performance tests, and submit reports of the results of such performance tests in accordance with § 60.8(a) through (f). [40 CFR§ 60.8(a) through (f)]

4. All required reports and other submittals under the NSPS program shall be submitted in duplicate to the Director, Region IX Air Division, US EPA, 75 Hawthorne Street, San Francisco, CA 94105. In addition, as required by 40 CFR 60.4(b), all reports and required submittals under the NSPS general provisions shall be submitted to PDEQ. [40 CFR § 60.4(b)]

D. Testing Requirements

For each RICE that is not certified, each performance test must be conducted following the requirements of 40 CFR §60.4244(a) through (g) and according to the requirements in 40 CFR §60.8.

1. Each performance test shall be conducted within 10% of the 100% peak (or highest achievable) load and according to the requirements in Table 2 of 40 CFR 60, Subpart JJJJ.

2. Performance tests shall not be conducted during periods of startup, shutdown, or malfunction as specified in 40 CFR §60.8(c). If the RICE is non-operational, the engine need not be started solely to conduct a performance test, but the performance test shall be conducted immediately upon startup of the engine.

3. For each required performance test, three separate test runs shall be performed. Each test run shall be conducted within 10% of the 100% peak (or highest achievable) load and last at least 1 hour.

4. To determine compliance with the NO_x, CO, and VOC mass per unit output emission limitation, convert the concentration of each pollutant in the engine exhaust using Equations of 40 CFR §60.4244.

IV. RECIPROCATING INTERNAL COMBUSTION ENGINES, UNITS RICE01-RICE10 – NESHAP SUBPART ZZZZ REQUIREMENTS

The conditions in this section apply to the reciprocating internal combustion engines – Units RICE01-RICE10 listed in Table VI, Attachment 2.

A. Emissions Limits and Standards

1. As required by 40 CFR § 63.6600(b), the permittee shall comply with the applicable emission limitations in Table 2a and operating limitations of Table 2b of Subpart ZZZZ.

2. Compliance with the emission limitations is based on the average of three 1-hour runs using the testing requirements and procedures in 40 CFR § 63.6620 and Table 4 of subpart ZZZZ as detailed in IV.D. Because each RICE to be installed at the IGS is a new, four stroke, lean burn, stationary RICE with a site rating > 500 brake horsepower and located at a major source of HAP emissions, the applicable emission limitations in Table 2a are as follows.

a. Except during periods of startup, when operating plus or minus 10 percent of 100 percent load, the Permittee shall reduce the CO emissions by 93 percent or more, or.

b. Except during periods of startup, when operating within plus or minus plus or minus 10 percent of 100 percent load, the Permittee shall limit the concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less, corrected to 15 percent O2. [40 CFR § 63.6600(b)]

3. During periods of startup, the permittee shall minimize the engine's time spent at idle and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitation applies. [40 CFR § 63.6625(h)]

4. Except during periods of startup, the permittee shall maintain the oxidation catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test. [40 CFR § 63.6600(b)]

5. Except during periods of startup, the permittee shall maintain the temperature of the stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F. [40 CFR § 63.6600(b)]

6. The permittee shall, at all times, operate and maintain each RICE, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the permittee to make any further efforts to reduce emissions if levels required under subpart ZZZZ have been achieved. [40 CFR § 63.6605]

B. Monitoring Requirements [40 CFR § 63.6625 & Table 5]

1. The Permittee shall prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of 40 CFR §63.6625 and in §63.8(d). As specified in §63.8(f)(4), the Permittee may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of 40 CFR §63.6625 in the site-specific monitoring plan.

2. The Permittee shall install, operate, and maintain continuous parameter monitoring system (CPMS) for each RICE. The CPMS shall be in continuous operation according to the procedures in the site-specific monitoring plan. Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, the Permittee shall monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

3. The CPMS shall collect data at least once every 15 minutes.

4. For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

5. The Permittee shall conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least annually.

6. The Permittee shall conduct a performance evaluation of each CPMS in accordance with the site-specific monitoring plan.

7. The CPMS shall be installed and monitoring parameters shall be established during the initial performance test. The following parameters shall be monitored during the performance test and during operation: [40 CFR §63.6625(b) and 63.6635]

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a. Catalyst inlet temperature

b. Catalyst pressure drop

C. *Recordkeeping and Reporting Requirements*

1. The Permittee shall submit semiannual compliance reports in accordance with the following provisions:

a. The first compliance report shall cover the period beginning on the date of startup and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the date of startup. The first compliance report shall be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the date of startup.

b. Each subsequent compliance report shall cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31 and shall be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

c. Each compliance report shall contain the company name and address, a statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report; and the date of the report and the beginning and ending dates of the reporting period.

d. If there are no deviations from any applicable emission limitations or operating limitations under subpart *ZZZZ*, the compliance report shall contain a statement that there were no deviations from the emission limitations or operating limitations during the reporting period.

e. If there were no periods during which the CPMS required by subpart *ZZZZ* was out-of-control, as specified in 40 CFR § 63.8(c)(7), the compliance report shall contain a statement that there were no periods during which the CPMS was out-of-control during the reporting period.

f. If the permittee had a deviation from any applicable emission limitation or operating limitation under subpart *ZZZZ* and for which the permittee is not using a CPMS to demonstrate compliance with the emission or operating limitations, the report shall contain, for each such deviation during the reporting period, the total operating time of the stationary RICE at which the deviation occurred during the reporting period; information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

g. If the permittee had a deviation from any applicable emission limitation or operating limitation under subpart *ZZZZ* and for which the Permittee is using a CPMS to demonstrate compliance with the emission or operating limitations, the report shall contain, for each such deviation during the reporting period, including any periods during which the CPMS required by subpart *ZZZZ* was out-of-control as specified in 40 CFR § 63.8(c)(7), the date and time that any malfunction started and stopped; the date, time, and duration that each CPMS was inoperative, except for zero (low-level) and high-level checks; the date, time, and duration that each CPMS was out-of-control, including the information in 40 CFR § 63.8(c)(8); the date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period; a summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period; a breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes; a summary of the total duration of CPMS downtime during the reporting period; and the total duration of CPMS downtime as a percent of the total operating

time of the stationary RICE at which the CPMS downtime occurred during that reporting period, an identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE; a brief description of the stationary RICE; a brief description of the CPMS; the date of the latest CPMS certification or audit; and a description of any changes in CPMS, processes, or controls since the last reporting period.

h. If the permittee had a malfunction during the reporting period, the report shall include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report shall also include a description of actions taken by TEP during a malfunction of an affected source to minimize emissions in accordance with 40 CFR § 63.6605(b), including actions taken to correct a malfunction. [40 CFR §63.6650]

i. The Permittee shall maintain records of each notification and report submitted to comply with 40 CFR§ 63 Subpart *ZZZZ*. [40 CFR § 63.6655(a)(2)]

j. The Permittee shall maintain records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment required by 40 CFR§ 63 Subpart *ZZZZ*. [40 CFR § 63.6655(a)(2)]

k. The Permittee shall maintain records of performance tests and performance evaluations as required by 40 CFR§ 63.10(b)(2)(viii). [40 CFR § 63.6655(a)(3)]

l. The Permittee shall maintain records of all required maintenance performed on the air pollution control and monitoring equipment. [40 CFR § 63.6655(a)(4)]

m. The Permittee shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR § 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. [40 CFR § 63.6655(a)(5)]

D. Testing Requirements

1. Within 180 days after startup, the permittee shall conduct the initial performance test on each RICE required by Table 4 of subpart *ZZZZ* according to the provisions in 40 CFR § 63.7(a)(2) and (a)(4). [40 CFR § 63.6612(a) and 63.6620(a)(4)]

2. The Permittee shall conduct subsequent performance tests on each RICE semiannually. After the Permittee has demonstrated compliance for two consecutive tests, the permittee may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the RICE is not in compliance with the applicable emission limitation, or the permittee deviates from any of the operating limitations required by 40 CFR § 63.6600(b), the permittee shall resume semiannual performance tests. [40 CFR § 63.6615 and 63.6620(a)(4)]

3. Formaldehyde

a. If the permittee elects to comply with the limit on formaldehyde concentration, the Permittee shall conduct a performance test for formaldehyde on each RICE consisting of three valid runs using either US EPA Method 320 or 323 of 40 CFR Part 63 or ASTM D6348-03.

b. Each test run shall be a minimum of 120 minutes with a minimum sample volume of 90 dscf.

c. Each engine shall be tested during in accordance with the schedule set forth in Table 3 and 4 of 40 CFR 63 Subpart *ZZZZ*.

[40 CFR § 63.6620]

4. Each initial and subsequent performance test shall be conducted at any load condition within plus or minus 10 percent of 100 percent load. [40 CFR § 63.6620(b)]

5. The engine percent load during a performance test shall be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination shall be included in the notification of compliance status required by 40 CFR §§ 63.9(h) and 63.6645(h). The following information shall be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test shall be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, strain gauges, etc. are used, the model number of the measurement device, and an estimate of its accuracy in percentage of true value shall be provided. [40 CFR § 63.6620(b)]

6. Each initial and subsequent performance test shall comprise three separate test runs and each test run shall last at least 1 hour. [40 CFR § 63.6620(d)]

7. For each initial and subsequent performance test, data shall be reduced in accordance with 40 CFR § 63.6620(e)(1)-(2), as applicable. [40 CFR § 63.6620(e)]

V. ELECTRIC STEAM GENERATING UNITS 'EGU'S' , UNITS 11, 12, AND 13

The conditions in this section apply to the fossil fuel fired electric steam generating units 'EGU's' - Units 11, 12, and 13 listed in Table 1, Attachment 2.

A. Emissions Limits and Standards [PCC 17.12.160.A.2]

1. Particulate Matter Standard

The Permittee shall not allow or permit the emission of particulate matter from any fossil fuel-fired steam generator in excess of the amounts calculated by the following equation:

$E = 1.02Q^{-.269}$ where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.
Q = the heat input in million Btu per hour. [PCC 17.16.160.C.1]
[Locally Enforceable Condition]

2. Sulfur Dioxide Standard

The Permittee shall not cause, allow, or permit the emission of more than 1.0 pound of sulfur dioxide as a three hour average per million Btu heat input when firing liquid fuel. [PCC 17.16.160.D.3]
[Locally Enforceable Condition]

3. Fuel Limitations

a. The Permittee shall only burn the following as fuel. [PCC 17.17.090 & PCC 17.12.130.A]
[Material Permit Conditions]

i. Natural gas;

ii. Fuel Oils #2 through #6 or equivalent;

iii. Co-firing Natural gas with Fuel Oils #2 through #6; or

iv. Co-firing any of the fuels listed above (II.A.3.a.i through ii of this Part) with Landfill Gas.

b. The Permittee shall not use high sulfur oil (fuel sulfur content > 0.90% by weight) as a fuel unless the Permittee demonstrates to the satisfaction of the Control Officer that sufficient quantities of low sulfur oil are not available for use by the source and that it has adequate facilities and contingency plans to insure that the sulfur dioxide ambient air quality standards set forth in PCC 17.08.020 will not be violated. [PCC 17.16.160.G]
[Locally Enforceable Condition]

B. Monitoring Requirements [PCC 17.12.180.A.3]

1. Visible Emissions When Firing Liquid Fuel

a. If liquid fuel is combusted in the unit continuously for a time period greater than 48 hours but less than 168 hours, (equal to one week), at least one opacity reading will be observed at the exit of the unit's stack.

b. When continuously firing liquid fuel for a time period greater than 168 hours, the Permittee shall conduct at least one opacity reading during each 168-hour period at the exit of the unit's stack by an employee certified in Method 9.

c. All opacity readings shall be observed in accordance with EPA Reference Method 9. The Permittee shall log in ink or in an unchangeable electronic format and maintain a record of the opacity readings from above and the number of hours fuel oil is burned continuously.

C. Recordkeeping & Reporting [PCC 17.12.180.A.4 & 5]

1. Particulate Matter

With regard to all liquid fuels, the Permittee shall keep on record, along with the fuel firing rate, the contractual agreement with the liquid fuel vendor indicating the following information concerning the liquid fuel being fired:

a. The heating value, and

b. The ash content.

2. Sulfur Dioxide

With regard to liquid fuel, the Permittee shall keep records of fuel supplier certifications including the following information:

a. The name of the fuel oil supplier;

b. The sulfur content of the oil from which the shipment came;

c. The heating content of the oil from which the shipment came;

d. The density of the fuel oil from which the shipment came; and

e. The method used to determine the sulfur content of the oil.

f. Engineering calculations demonstrating compliance with the standard shall be performed each time there is a change in conditions II.C.2.b, c, or d above. These calculations shall be performed according to the following equation and maintained in a record:

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$$SO_2 = \frac{2.0 \times \%S \times D_f}{HV} \times \frac{1{,}000{,}000 lbs}{MMBtu}$$

where:

SO_2 = emissions of SO_2 in lb/MMBtu

%S = Percent Sulfur by weight (decimal; i.e. 1% = 0.01)

D_f = Density of fuel in lb/gal

HV = Heating value of fuel in Btu/gal

3. Fuel Limitations

Except for fuels fired during startup and/or flame stabilization, the Permittee shall log in ink or in an electronic format a record of any change in fuel type including the following information:

a. Type of fuel change, and

b. Date and time of fuel change.

4. Hours of Operation

Until the performance tests specified in B.D.1 of this Part are completed, the Permittee shall compute and record the following information in an individual log for each unit within 5 working days of the end of each month:

a. Date and time in which the unit began firing liquid fuel (exclusively or in combination); if liquid fuel combustion began in the previous month, the record shall state the fact;

b. The date and time in which the unit ceased to fire liquid fuel (exclusively or in combination); if liquid fuel combustion continues into the next month the record shall state that fact;

c. The hours of operation during which liquid fuel was fired (exclusively or in combination) in the previous month, including consecutive hours and total hours;

d. The hours of operation during which liquid fuel was fired (exclusively or in combination) in the previous 12-consecutive month period.

5. Special Reporting for the Affected Source or Process

The Permittee shall promptly notify and submit written reports to the Control Officer of any instances of excess emissions or deviation from permit requirements. (Refer to N.1.A & B. of Part A).

B. Testing Requirements [IDCC 17.12.130.A.5]

For purposes of demonstrating compliance, these test methods shall be used, provided that for the purpose of establishing whether or not the facility has violated or is in violation of any provision of this permit, nothing in this permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable federal requirements if the appropriate performance or compliance procedures or methods had been performed.

The Permittee shall use the following EPA approved reference test methods to conduct performance tests for the specified pollutants when required.

1. Sulfur Dioxide

The Permittee shall perform an annual performance test in accordance with EPA Reference Method 6 or 6C when liquid fuel is fired greater than 1300 hours in a 12 consecutive month period.

E. Shutdown of Unit 11 and/or Unit 12

1. The permittee shall permanently shutdown Unit 11 and Unit 12 prior to startup of the first RICE unit. [40 CFR 52.21(b)(41)(ii)(a) 40 CFR 60.2]

VI. ELECTRIC STEAM GENERATING UNIT 'EGU' – UNIT 14

This section applies to the fossil fuel fired electric steam generating unit 'EGU' – Unit 14 listed in Table 1, Attachment 2.

A. Emission Limits & Standards (Unit 14) [IDCC 17.12.130.A.5]

1. Particulate Matter Standard [IDCC 17.12.160.C.1]
[Locally Enforceable Condition]

The Permittee shall not cause, allow, or permit the emission of particulate matter from any fossil fuel-fired steam generator in excess of the amounts calculated by the following equation:

$E = 1.02Q^{-.269}$ where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.
Q = the heat input in million Btu per hour

2. Nitrogen Oxides Standards

The Permittee shall not cause, allow, or permit the emission of more than 0.7 pounds of nitrogen oxides as a three hour average (calculated as nitrogen dioxide) per million BTU heat input.
[Conditions Permit # 1456, Condition 5]
[Material Permit Condition]

3. Fuel Limitations

a. The Permittee shall only burn the following as fuel: [IDCC 17.12.130.A.5 IDCC 17.12.130.B.a]
[Material Permit Conditions]

i. Natural Gas.

ii. Co-Firing Natural Gas with Landfill Gas.

4. Regional Haze Requirements (See section IV.C and IV.D of Part B) [40 CFR 52.1620(c)]

B. Monitoring Requirements (Unit 14) [PCC 17.12.180.A.3]

1. Nitrogen Oxides [40 CFR 75.10, PCC 17.12.060.E.3 & 6, & PCC 17.16.160.B]
[Material Permit Condition]

The Permittee shall install, certify, operate and maintain in accordance with the general operating requirements of 40 CFR Part 75.10 a NO_x – diluent continuous emission monitoring system with an automated data acquisition and handling system (DAHS) to determine, measure, and record NO_x concentration (in ppm), O_2 or CO_2 (in percent) and NO_x emission rate (in lb/MMBtu) discharged to the atmosphere except as otherwise approved by the Administrator of the EPA.

2. Opacity

a. The Permittee shall install, maintain, calibrate, and operate a continuous opacity monitoring system (COMS). [Installation Permit #8156, Condition 16]
[Material Permit Condition]

b. The COMS shall meet the following requirements:

i. 40 CFR 60, Appendix B, Performance Specification, Specification and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources.

(a) What are the basic requirements of PS-1? [40 CFR 60, Appendix B, Section 1.0]

(b) What performance procedures are required to comply with PS-1? [40 CFR 60, Appendix B, Section 8.0]

(c) What quality control measures are required by PS-1? [40 CFR 60, Appendix B, Section 9.0]

(d) What calculations are needed? [40 CFR 60, Appendix B, Section 12.0]

(e) What specification does a COMS have to meet for certification? [40 CFR 60, Appendix B, Section 13.0]

ii. Calibration Checks

The Permittee shall record the zero and span drift in accordance with the method described by the manufacturer's recommended zero and span check at least once daily unless the manufacturer has recommended adjustments at shorter intervals, in which case such recommendations shall be followed. [PCC 17.12.060.D.6]

(a) Zero and Span Drift Adjustments [PCC 17.12.060.D & 40 CFR 60.13(d)(1)]

(i). Permittee shall adjust the zero or span whenever the 24-hour zero drift or 24-hour calibration drift limits of 2% opacity are exceeded.

(ii). The system shall allow for the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified.

(iii). The optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments.

(iv). The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4% opacity.

(b) System Checks [40 CFR 60.13(d)(1)]

Each analyzer shall include a calibration system for simulating a zero opacity (or no greater than 10%) condition and an upscale opacity condition for the purposes of performing periodic checks of the transmissometer calibration while on an operating stack or duct. This calibration will provide, as a minimum, a system check of the analyzer internal optics and all electronic circuitry including the lamp and photodetector assembly.

(c) Minimum Frequency of Operation [40 CFR 60.13(e)(1)]

Except during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments, the COMS shall be in continuous operation and shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(d) Data Reduction and Missing Data [40 CFR 60.13(h)(1)]

(i). Permittee shall reduce all data from the COMS to 6-minute averages. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period.

(ii). Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under the previous paragraph. An arithmetic or integrated average of all data may be used. [40 CFR 60.13(h)(2)(ii)]

3. Regional Haze Requirements

(See section VII.D of Part B).

C. Recordkeeping & Reporting (Unit 14) [PCC 17.12.180.A.4 & 5]

1. Quarterly Reports for NO_x CEMS [PCC 17.12.060.E.3 and 6, 40 CFR 75.73]

a. Permittee shall submit a written report of all deviations to PDEQ on January 31st, April 30th, July 31st, and October 31st, covering October through December, January through March, April through June, and July through September, respectively. The reports shall include the following:

i. The magnitude of deviations computed in accordance with PCC 17.12.060, any conversion factor(s) used, and the date and time of commencement and completion of each time period of deviation.

ii. Specific identification of each period of deviation that occurs during startups, shutdowns, and malfunctions of the boiler. The nature and cause of any malfunction (if known) and the corrective action taken or preventative measures adopted shall also be reported.

iii. The date and time identifying each period during which the continuous monitoring system(s) were inoperative except for zero and span checks and the nature of the system repairs or adjustments. The Control Officer may require proof of continuous monitoring system performance whenever system repairs or adjustments have been made. [PCC 17.12.060.E.4]

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iv. When no excess emissions have occurred and the continuous monitoring systems have not been inoperative, repaired, or adjusted, such information shall be clearly stated in the report. [PCC 37.6.a.(iii) & (v)]

b. In addition to the requirements of the above paragraph (III.C.2.a. of this Part), the Permittee shall report all deviations in accordance with XI.B of Part A.

2. Regional Haze Requirements

(See section V.E through V.G of Part B).

3. Special Reporting for the Affected Source or Process

The Permittee shall promptly notify and submit written reports to the Control Officer of any instances of excess emissions or deviation from permit requirements. (Refer to XI.A & D of Part A).

D. Testing Requirements (Unit 14) [PCC 37.12.b.(iii) & V.A & PCC 37.20.a.(iii)]

For purposes of demonstrating compliance, these test methods shall be used, provided that for the purpose of establishing whether or not the facility has violated or is in violation of any provision of this permit, nothing in this permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable federal requirements if the appropriate performance or compliance procedures or methods had been performed.

The Permittee shall use the following EPA approved reference test methods to conduct performance tests or relative accuracy test audits (RATA's) for the specified pollutants when required:

1. Testing shall be conducted in accordance with EPA Reference Method 7 for nitrogen oxides.

2. Regional Haze Test Requirements (See Section IV.C and IV.D of Part B).

VII. UNIT 14 – REGIONAL HAZE IMPLEMENTATION PLAN [40 CFR 52.145(j)]

This section applies to the fossil fuel fired electric steam generating unit "EGU" – Unit 14 listed in Table 1, Attachment 3. [40 CFR 52.145(j)(1)]

A. Definitions [40 CFR 52.145(j)(2)]

For the purpose of this section:

1. *Boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit.

2. *Continuous emission monitoring system or CEMS* means the equipment required by 40 CFR Part 75 and this section.

3. *MMBtu* means one million British thermal units.

4. *Natural gas* means a naturally occurring fluid mixture of hydrocarbons as defined in 40 CFR 72.2.

5. *NO_x* means oxides of nitrogen.

6. *PM_{10}* means total particulate matter less than 10 microns in diameter.

7. *SO_2* means sulfur dioxide.

B. Compliance Date

The Permittee shall comply with the NO_x, SO_2, and PM_{10} emission limitations of condition IV.C of this section no later than December 31, 2017. [40 CFR 52.145(j)(6)]

C. Emissions Limitations [PCC 37.12.b.(iii) & A.3]

1. The Permittee shall combust only natural gas or natural gas combined with landfill gas.

2. The Permittee shall not emit or cause to be emitted pollutants in excess of the following limitations, in pounds of pollutant per million British thermal units (lb/MMBtu): [40 CFR 52.145(j)(3)(i)]

a. NO_x – 0.25 lbs/MMBtu

b. SO_2 – 0.057 lbs/MMBtu

c. PM_{10} – 0.010 lbs/MMBtu

3. If the results of the initial performance test conducted in accordance with condition IV.D.4 of this section show PM_{10} emissions greater than the limit in condition IV.C.2.c of this section, the owner/operator may elect to comply with an emission limit equal to the result of the initial performance test, in lieu of the PM_{10} emission limit in condition IV.C.2.c of this section. [40 CFR 52.145(j)(3)(ii)]

D. Compliance Determination [PCC 37.12.b.(iii) & A.3]

1. Continuous emission monitoring system (CEMS) [40 CFR 52.145(j)(4)(i)]

a. At all times after the compliance date specified in IV.B of this section, the Permittee of the unit shall maintain, calibrate, and operate CEMS, in full compliance with the requirements found at 40 CFR part 75. All valid CEMS hourly data shall be used to determine compliance with the emission limitation for NO_x in IV.C.2.a of this section. When the CEMS is out-of-control as defined by 40 CFR Part 75, the CEMS data shall be treated as missing data and not used to calculate the emission average. Each required CEMS must obtain valid data for at least ninety (90) percent of the unit operating hours, on an annual basis. [40 CFR 52.145(j)(4)(i)(A)]

b. The Permittee of the unit shall comply with the quality assurance procedures for CEMS found in 40 CFR Part 75. The CEMS monitoring data shall not be bias adjusted. [40 CFR 52.145(j)(4)(i)(B)]

2. Compliance Determination for NO_x [40 CFR 52.145(j)(4)(ii)]

Compliance with the NO_x emission limit described in condition IV.C.2.a of this section shall be determined based on a rolling 30 boiler-operating-day basis. The rolling 30 boiler-operating-day NO_x emission rate for the unit shall be calculated for each boiler operating day in accordance with the following procedure:

a. Step one, sum the hourly pounds of NO_x emitted for the current boiler operating day and the preceding twenty-nine (29) boiler-operating-days to calculate the total pounds of NO_x emitted over the most recent thirty (30) boiler-operating-day period for that unit;

b. Step two, sum the total heat input, in MMBtu, during the current boiler operating day and the preceding twenty-nine (29) boiler-operating-days to calculate the total heat input over the most recent thirty (30) boiler-operating-day period for that unit;

c. Step three, divide the total amount of NO_x calculated from Step one by the total heat input calculated from Step two to calculate the rolling 30-boiler-operating-day NO_x emission rate, in pounds per MMBtu for that unit. Each rolling 30-boiler-operating-day NO_x emission rate shall

include all emissions and all heat input that occur during all periods within any boiler operating day, including emissions from startup, shutdown, and malfunction. If a valid NO_X pounds per hour or heat input is not available for any hour for the unit, that heat input and NO_X pounds per hour shall not be used in the calculation of the rolling 30-boiler-operating-day emission rate.

3. Compliance Determination for SO_2 [40 CFR 52.145(g)(3)(ii)(B)]

Compliance with the SO_2 emission limit shall be determined from fuel sulfur documentation demonstrating the use of either natural gas or natural gas combined with landfill gas.

4. Compliance Determination for PM_{10} [40 CFR 52.145(g)(3)(ii)(C)]

Compliance with the PM_{10} emission limit shall be determined from performance stack tests. Within sixty (60) days following the compliance deadline specified in Condition IV.B of this section, and at the request of the Regional Administrator thereafter, the Permittee shall conduct a stack test to measure PM_{10} using EPA Methods 1 through 4, 201A, and Method 202, per 40 CFR Part 51, Appendix M. Each test shall consist of three runs, with each run at least one hundred twenty (120) minutes in duration and each run collecting a minimum sample of sixty (60) dry standard cubic feet. Results shall be reported in lb/MMBtu using the calculation in 40 CFR Part 60, appendix A, Method 19.

E. Recordkeeping [PCC 17.32.190.A.4 & 40 CFR 52.145(g)(3)(i)]

The Permittee shall maintain the following records for at least five years:

1. CEMS data measuring NO_X in lb/hr and heat input rate per hour.
2. Daily rolling 30-boiler operating day emission rates of NO_X calculated in accordance with Condition IV.D.2 of Part B of this permit.
3. Records of the relative accuracy test for NO_X lb/hr measurement and hourly heat input measurement.
4. Records of quality assurance and quality control activities for emissions systems including, but not limited to, any records required by 40 CFR Part 75.
5. Records of all major maintenance activities conducted on emission units, air pollution control equipment, and CEMS.
6. Any other records required by 40 CFR Part 75.
7. Records sufficient to demonstrate that the fuel for the unit is natural gas or natural gas combined with landfill gas.
8. All PM_{10} stack test results.

F. Notifications [PCC 17.12.180.A.5 & 40 CFR 52.145(g)(3)(i)]

1. All notifications required under this section shall be submitted by the Permittee to the Director, Enforcement Division (Mail Code ENF-2-1), U.S. Environmental Protection Agency, Region 9, 75 Hawthorne Street, San Francisco, California 94105-3901.
2. By March 31, 2017, the Permittee shall submit notification by letter that it will comply with the emission limits in Condition IV.C. of this section. [40 CFR 52.145(g)(1)(ii)]
3. The Permittee shall submit notification of its intent to comply with the PM_{10} emission limit in Condition IV.C.2.c of this section within one hundred twenty (120) days following the compliance

deadline specified in condition IV.B of this section. The notification shall include results of the initial performance test and the resulting applicable emission limit. [40 CFR 52.145(g)(1)(iv)]

G. Reporting [PCC 17.12.180.A.5 & 40 CFR 52.145(g)(3)]

1. All reports required under this condition shall be submitted by the Permittee to the Director, Enforcement Division (Mail Code ENF-2-1), U.S. Environmental Protection Agency, Region 9, 75 Hawthorne Street, San Francisco, California 94105-3901. All repors required under this Condition shall be submitted within 30 days after the applicable compliance date(s) in Condition IV.B of this section and at least semiannually thereafter, within 30 days after the end of a semiannual period. The Permittee may submit reports more frequently than semiannually for the purposes of synchronizing reports required under this section with other reporting requirements, such as the title V monitoring report required by 40 CFR 70.6(a)(3)(iii)(A), but at no point shall the duration of a semiannual period exceed six months.
2. The Permittee shall submit a report that lists the daily rolling 30-boiler operating day emission rates for NO_X. [40 CFR 52.145(g)(1)(i)]
3. The Permittee shall submit excess emissions reports for NO_X limits. Excess emissions means emissions that exceed the emission limit specified in Condition IV.C.2.a of this section. The reports shall include the magnitude, date(s), and duration of each period of excess emissions; specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the unit; the nature and cause of any malfunction (if known); and the corrective action taken or preventative measures adopted. [40 CFR 52.145(g)(1)(ii)]
4. The Permittee shall submit CEMS performance reports, to include dates and duration of each period during which the CEMS was inoperative (except for zero and span adjustments and calibration checks), reason(s) why the CEMS was inoperative and steps taken to prevent recurrence, and any CEMS repairs or adjustments. [40 CFR 52.145(g)(1)(iii)]
5. The Permittee shall submit the results of any relative accuracy test audits performed during the two preceding calendar quarters. [40 CFR 52.145(g)(1)(iv)]
6. When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted during the reporting period, the Permittee shall state such information in the semiannual report. [40 CFR 52.145(g)(1)(v)]
7. The Permittee shall submit results of any PM_{10} stack tests conducted for demonstrating compliance with the PM_{10} limit specified in condition IV.C.2.c of this section. [40 CFR 52.145(g)(1)(vi)]

H. Equipment Operations [PCC 17.12.180.A.2 & 40 CFR 52.145(g)(1)(i)]

At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate the unit, in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available, which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the unit.

I. Enforcement [PCC 17.12.180.A.3.a, PCC 17.20.180, & 40 CFR 52.145(g)(1)(i)]

Notwithstanding any other provision in this implementation plan, any credible evidence or information relevant as to whether the unit would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed can be used to establish whether or not the owner/operator has violated or is in violation of any standard or applicable emission limit in the plan

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Part B

VIII. COOLING TOWERS (11E, 12D, 13D, & 14E)

This section applies to the industrial process cooling towers (11E, 12D, 13D, & 14E) in Table III of Attachment 2.

A. Emission Limits & Standards (11E, 12D, 13D, & 14E) [PCC 17.13.1.B.5.A.2]

1. Particulate Matter Standard [PCC 17.16.1.B.1.a]

[Locally Enforceable Condition]

The Permittee shall not cause or allow particulate emissions from the cooling towers to exceed.

$E = 17.31P^{0.16}$ where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.
P = the process rate in tons-mass per hour.

2. Industrial Process Cooling Tower Standard

The Permittee shall not use chromium-based water treatment chemicals in the cooling towers.

[40 CFR 63.402 & PCC 17.13.1.B.6.B]

[Material Permit Condition]

B. Reporting Requirements (11E, 12D, 13D, & 14E) [PCC 17.13.1.B.6.B]

1. Special Reporting for the Affected Source or Process

The Permittee shall promptly notify and submit written reports to the Control Officer of any instances of excess emissions or deviation from permit requirements. (Refer to NLA & B of Part A).

IX. STATIONARY ROTATING MACHINERY

This section applies to the gas turbines IGT1 and IGT2 listed in Table IV, Attachment 2.

A. Emission Limits and Standards (IGT1, IGT2) [PCC 17.13.1.B.5.A.2]

1. Particulate Matter Standard [PCC 17.16.1.B.1.c]

The Permittee shall cause, allow, or permit the emission of particulate matter, caused by combustion of fuel, from any of the stacks of stationary rotating machinery in excess of the amounts calculated by the following equation:

$E = 1.02Q^{0.769}$ where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.
Q = the heat input in million Btu per hour.

2. Sulfur Dioxide Standard

The Permittee shall not emit more than 1.0 pounds of sulfur per million Btu heat input when firing low sulfur oil. [PCC 17.16.1.B.1.f]

3. Opacity Standard

The Permittee shall not cause, allow or permit to be emitted into the atmosphere from any stationary rotating machinery, smoke for any period of time greater than ten consecutive seconds which exceeds 40 percent opacity. Visible emissions when starting cold equipment shall be exempt from this requirement for the first ten minutes. [PCC 17.16.1.B.1.b, PCC 17.23.1.B.1.a & PCC 17.16.1.B.1.b]

[Federally Enforceable when opacity is greater than 40%]

4. Fuel Limitations

a. The Permittee shall not use high sulfur oil (fuel sulfur content > 0.90% by weight) as a fuel unless the Permittee demonstrates to the satisfaction of the Control Officer that sufficient quantities of low sulfur oil are not available for use by the source and that it has adequate facilities and contingency plans to insure that the sulfur dioxide ambient air quality standards set forth in PCC 17.08.020 will not be violated. [PCC 17.16.1.B.1.g]

[Locally Enforceable Condition]

b. The Permittee shall only burn the following as fuel in UNITS IGT1 and IGT2: [PCC 17.13.2.B.6.a]

i. Natural gas;

ii. Fuel oil: #2 Distillate, or equivalent;

iii. Co-firing natural gas with Fuel oil #2 Distillate or equivalent.

c. The Permittee shall only burn diesel as fuel in UNITS IGT1A and IGT2A (stationary turbine starter engines). [PCC 17.13.2.B.6.b]

B. Monitoring Requirements [PCC 17.13.2.B.6.A.1]

1. Visible Emissions

a. If liquid fuel is burned in a unit continuously for a time period greater than 48 hours but less than 168 hours, at least one six minute opacity reading will be observed at the exit of the unit's stack.

b. If liquid fuel is burned in a unit continuously for a time period greater than 168 hours, at least one six-minute opacity reading will be observed during each 168-hour period, at the exit of the unit's stack.

c. All opacity readings will be observed in accordance with EPA Reference Method 9. The Permittee shall log in ink or in an unchangeable electronic format and maintain a record of the opacity readings from above and the number of hours fuel oil is continuously burned.

2. Sulfur Dioxide

For units firing gaseous fuels, the Permittee shall monitor daily, the sulfur content of the fuel being combusted in these machines. This requirement may be complied with by maintaining a vendor-provided copy of that part of the Federal Energy Regulatory Commission (FERC)-approved Tariff agreement that limits transmission of pipeline quality natural gas of sulfur content to less than 0.9 percent by weight. [PCC 17.16.1.B.1.e]

3. Hours of Operation

The Permittee shall keep track of the hours of operation, computed as a twelve-month rolling total, until the performance tests specified in VII.E.1 & 2 of this Part are completed.

C. Recordkeeping [PCC 17.12.180.A.4]

1. Particulate Matter

a. The Permittee shall keep on record, along with the fuel firing rate, the contractual agreement with the liquid fuel vendor indicating the following information concerning the liquid fuel fired in any stationary rotating machinery:

i. The heating value; and

ii. The ash content:

b. The Permittee shall calculate the particulate matter emissions based on the above values for each applicable unit. The Permittee shall perform this calculation each time there is a change related to VI.C.1.a.i or ii of Part B above in the contractual agreement. These calculations shall be maintained in a record.

2. Sulfur Dioxide

a. For units firing liquid fuels, the Permittee shall keep records of fuel supplier certifications including the following information:

i. The name of the oil supplier;

ii. The sulfur content and the heating content of the oil from which the shipment came; and

iii. The method used to determine the sulfur content of the oil.

iv. Engineering calculations demonstrating compliance with VI.A.2 of Part B shall be performed each time there is a change in VI.C.2.ii of Part B above). These calculations shall be maintained in a record.

b. Fuel analysis shall be used to determine the sulfur content of fuel used. The Permittee may also use fuel sulfur content certifications that employ the following test methods: ASTM D 129-91 shall be used to determine the sulfur content of liquid fuels and ASTM D-1702-90, D 1072-80, D3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels. The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Control Officer.

D. Reporting Requirements [PCC 17.12.180.A.5]

1. Sulfur Content of Fuels

The Permittee shall report any daily period during which the sulfur content of fuels fired in any piece of stationary rotating machinery exceeds 0.8 percent by weight in the semiannual report of required monitoring in I.E of this Part. [PCC 17.16.340.B]

2. Special Reporting for the Affected Source or Process

The Permittee shall promptly notify and submit written reports to the Control Officer of any instances of excess emissions or deviation from permit requirements. (Refer to XI.A & B of Part A).

E. Testing Requirements [PCC 17.12.180.A.3.a & PCC 17.16.340.B]

For purposes of demonstrating compliance, these test methods shall be used, provided that for the purpose of establishing whether or not the facility has violated or is in violation of any provision of this permit, nothing in this permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable federal requirements if the appropriate performance or compliance procedures or methods had been performed.

The Permittee shall use the following EPA approved reference test methods to conduct performance tests for the specified pollutants when required:

1. Sulfur Dioxide

The Permittee shall perform an annual performance test in accordance with EPA Reference Method 6 or 6C when liquid fuel is fired greater than 1300 hours in a 12 consecutive month period.

2. Carbon Monoxide [A.R.S. 49-422.A.3]

The Permittee shall perform a performance test to measure the emission rate of carbon monoxide. This performance test shall be conducted after the twelve month rolling total hours of operation exceeds 4500 hours. The performance test shall be performed in accordance with EPA Reference Method 10.

X. INTERNAL COMBUSTION ENGINES - LOCAL REQUIREMENTS

In addition to sections VIII or IX, as applicable, this section applies to EGEN1 and the gas turbine starter engines identified in Table V of Attachment 2, regulated under NESHAP program.

A. Emission Limits and Compliance Determination [PCC 17.12.180.A.2, 3 & 4]

1. Opacity Standard [PCC 17.12.180.A.2, 3 & 4]
[Locally Enforceable Conditions]

a. The Permittee shall not cause, allow or permit to be emitted into the atmosphere from any stationary rotating machinery, smoke for any period of time greater than ten consecutive seconds which exceeds 40 percent opacity. Visible emissions when starting cold equipment shall be exempt from this requirement for the first ten minutes. [PCC 17.16.040, & PCC 17.16.340.E]
[Federally Enforceable when opacity is greater than 40%]

b. The Permittee shall not cause or permit the effluent from a single emission point, multiple emission point, or a fugitive emissions source to have an average optical density equal to or greater than 60 percent when a cold diesel engine is started or when a diesel engine is accelerated under load as measured in accordance with EPA Method 9. [PCC 17.16.040]

c. The Permittee shall conduct a visible emissions check on the exhaust stack of each emergency generator (excluding starter engines) at least quarterly while the generator is operating. For the purposes of this permit, a visible emission check is verification that abnormal emissions are not present at the generator stack. The Permittee shall record the date and time of the check, the name of the person conducting the check, the results of the check, and the type of corrective action taken (if required). All records shall be maintained for five years. [PCC 17.12.180.A.3]

d. When requested by the Control Officer, the Permittee shall perform EPA Method 9 visible emissions observations on the RICE and the generator(s) to demonstrate compliance with the opacity standard. At any time that the permittee is burning natural gas in emissions units RICE01 through RICE10, the permittee is not required to conduct any visible emissions or particulate

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matter monitoring because it is extremely unlikely that these standards could be violated while burning natural gas.

2. Fuel Limitation [PCC 17.12.180 A.2, 3 & 4]

a. The Permittee shall burn only the specified fuel(s) allowed for each generator in the equipment list. The Permittee shall only fire fuel less than 0.90% by weight of sulfur [PCC 17.12.180 B]
[Material Permit Condition]

b. In order to demonstrate compliance with the fuel limitation required in VII.A.3.a of this Attachment, the Permittee shall maintain records of fuel supplier specifications which verify the sulfur content of the fuel, piped and/or as delivered. All records shall be maintained for five years.

XI. NESHAP SUBPART ZZZZ REQUIREMENTS FOR EMERGENCY GENERATORS – GT1A, GT2A, & EGEN1

This section applies to the starter engines GT1A and GT2A and the emergency generator identified as EGEN1 in Table V of Attachment 2.

A. Applicability

1. This section applies to existing stationary RICE with a site rating of more than 500 brake horsepower located at a major source of HAP emissions that commenced construction or reconstruction before December 19, 2002, or existing stationary RICE with a site rating less than or equal to 500 hp at a major source of HAP emissions that commenced construction or reconstruction before June 13, 2006 that are identified as such in Table V of Attachment 2. [40 CFR 63.6590(a)(1)(iii) and (b)(1)(i)]

2. The Permittee shall comply with the terms of this Section no later than May 3, 2013 for existing stationary RICE with a site rating less than or equal to 500 brake horsepower, and no later than June 15, 2007 for existing stationary RICE with a site rating more than 500 brake horsepower. [40 CFR 63.6595(a)(1)]

B. Operating Requirements [PCC 17.12.180 B]

1. The Permittee must be in compliance with the applicable emission/operating limitations at all times. [40 CFR 63.6605(a)]

2. At all times the Permittee shall operate and maintain the ICE, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the Permittee to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Director which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR 63.6605(b)]

3. The Permittee shall minimize the ICE's time at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes. [40 CFR 63.6625(h)]

4. Except during periods of startup, the Permittee shall meet the following requirements for each generator and gas turbine diesel starter engine:

a. Change oil and filter every 500 hours of operation or annually, whichever comes first;

b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and

c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. [40 CFR 63.6602 Table 2c - Row 1 of Subpart ZZZZ]

5. The Permittee may opt to utilize an oil analysis program in order to extend the oil change requirement specified in Condition VIII.B.4 in this section. The oil analysis shall be performed at the same frequency specified in Condition IX.B.4. The analysis program shall at a minimum analyze the following three parameters. [40 CFR 63.6625(i)]

a. Total base number;

b. Viscosity, and

c. Percent water content.

The condemning limits for these parameters are as follows:

a. Total base number is less than 30 percent of the total base number when oil is new,

b. Viscosity of the oil has changed by more than 20 percent from the viscosity of oil when new, and

c. Percent water content by volume is greater than 0.5.

6. The Permittee shall operate and maintain each generator subject to this section according to manufacturer's emission-related written instructions or develop its own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. [40 CFR 63.6625(e) Table 6, Item 9]

7. The Permittee must install a non-resettable hour meter on EGEN1 if one is not already installed. [40 CFR 63.6625(f)]

8. The Permittee shall operate the emergency stationary RICE under this section according to the requirements in paragraphs VIII.B.8.a through c below. In order for the engine to be considered an emergency stationary RICE, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs VIII.B.8.a through c below, is prohibited. If not operated according to the requirements in paragraphs VIII.B.8.a through c below, the engine will not be considered an emergency engine under this section and must meet all requirements for non-emergency engines. [40 CFR 63.6640(f)]

a. The emergency stationary RICE under this section may be operated to provide electrical power or mechanical work during an emergency situation, such as its use to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted. There is no time limit on the use of the emergency stationary RICE in emergency situations. [40 CFR 63.6640(f)(1) and (4)(i)]

b. The emergency stationary RICE under this section may be operated for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The Permittee may petition for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the Permittee maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year. Any

operation for non-emergency situations as allowed by paragraph VIII.B.8.c below counts as part of the 100 hours per calendar year allowed under this paragraph. [40 CFR 63.6640(f)(3)]

c. The emergency stationary RICE under this section may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and readiness testing provided in paragraph VIII.B.8.b above [40 CFR 63.6640(f)(3)]

C. **Reporting, Recordkeeping, and Notification Requirements** [PCC 17.12.180.A.4 & 5]

1. The Permittee shall keep records in a form suitable and readily available for expeditious review according to 40 CFR 63.10(b)(1). [40 CFR 63.6660(a)]

2. The Permittee shall keep each record for 5 years following the date of each occurrence, maintenance, corrective action, report, or record. [40 CFR 63.6660(b)]

3. The Permittee shall keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, maintenance, corrective action, report, or record. [40 CFR 63.6660(c)]

XII. NSPS SUBPART IIII EMERGENCY GENERATOR REQUIREMENTS

This section applies to the NSPS emergency generator identified as EGEN2 in the equipment list. All standards are federally enforceable unless indicated otherwise.

A. **Emission Limits and Standards** [PCC 17.12.180.A.2 & 3]

1. Certified Emission Limits [40 CFR 4205(b), 40 CFR 60.4202(a) & (2), 40 CFR 89.112(a)]

a. New Compression Ignition Internal Combustion Engines (CI ICE) subject to this Section shall be certified by the manufacturer at or below the applicable emission standards and shall continue to meet them for the useful life of the engine. [40 CFR 60.4206]

b. For 2007 model year and later stationary CI ICE subject to this Attachment, the Permittee shall comply with the emission standards by purchasing an engine certified to the emission standards of permit condition IX.A.1.b. (40 CFR 60.4205(b), for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications. Applicable emission standards are identified in the table below: [40 CFR 60.4231(a)] [PCC 17.12.180.A.4]

Maximum Engine Power	Model Year	NMHC+ NO_X (g/kW-hr)	CO (g/kW-hr)	PM (g/kW-hr)
600 ≤ HP <750	≥2007	4.0	3.5	0.20

c. The Permittee must operate and maintain applicable units according to the manufacturer's written instructions or procedures developed by the Permittee that are approved by the engine manufacturer, over the entire life of the engine. [40 CFR 60.4206]

2. Operational Limitation [40 CFR 60.4211(a)] [PCC 17.12.180.B.2]

a. Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local

government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. The Permittee may petition the Control Officer for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the Permittee maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. Any operation other than emergency operation, and maintenance and testing as permitted in this Attachment, is prohibited. [40 CFR 60.4211(f)(3)]

b. The Permittee must operate and maintain the applicable stationary CI ICE and control device (if any) according to the manufacturer's written instructions or procedures developed by the Permittee that are approved by the engine manufacturer. In addition, the Permittee may only change those settings that are permitted by the manufacturer. The Permittee must also meet the requirements of 40 CFR Part 89, as they apply to the Permittee. [40 CFR 60.4211(a)]

3. Fuel Limitation [PCC 17.12.180.A.2]

Stationary CI ICE subject to this section that use diesel fuel must use diesel fuel that meets the following requirements on a per-gallon basis: [40 CFR 60.4207(b) & 80.510(b)]

a. Sulfur content: 15 ppm maximum.

b. Cetane index or aromatic content, as follows:

i. A minimum Cetane index of 40; or

ii. A maximum aromatic content of 35 volume percent.

4. Additional Requirements [40 CFR 60.4218 & 60.4214(b)]

The General Provisions of 40 CFR 60.1 through 19 apply to applicable sources as indicated in Table 8 of 40 CFR Subpart IIII except that the Permittee is not required to submit an initial notification.

B. **Monitoring Requirements** [PCC 17.12.180.A.3]

The Permittee shall install and maintain a non-resettable hour meter on each applicable stationary CI ICE prior to startup of each engine. [40 CFR 60.4209(a)]

C. **Recordkeeping Requirements** [PCC 17.12.180.A.4]

1. The Permittee shall show compliance with condition IX.A.1.b. in this section by maintaining manufacturer purchase records that show compliance with the emission rates. [40 CFR 60.4211(c) & PCC 17.12.180.A.4]

2. The Permittee shall record the monthly operating hours and recalculate a rolling twelve (12) month total within 30 calendar days following the end of the month. [PCC 17.12.180.A.3 & 4]

3. The Permittee shall maintain records of fuel supplier certifications that show and verify compliance with all the diesel fuel requirements in IX.A.3.of this attachment.

4. All records required by, this section, shall be maintained for five years from the date of record.

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B. Testing Requirements [40 CFR 60.4212 & PCC 17.16.190.A.1.a]

Should the Permittee elect to or be required to conduct performance testing to demonstrate compliance with the applicable standards of this Attachment, the Permittee shall do so in accordance with 40 CFR 60.4212.

XIII. NONPOINT FUGITIVE DUST SOURCES

A. Emission Limits and Standards [PCC 17.12.190.A.2 & 3]

1. The Permittee is authorized to conduct fugitive dust producing activities at the facility in accordance with PCC 17.16.300 and is responsible for controlling windblown dust, dust from haul roads, and dust emitted from land clearing, earthmoving, demolition, trenching, blasting, road construction, mining, racing event, and other activities, as applicable.

   a. Until the area becomes permanently stabilized by paving, landscaping or otherwise, dust emissions shall be controlled by applying adequate amounts of water, chemical stabilizer, or other effective dust suppressant. [PCC 17.16.050.A]

   b. The Permittee shall not leave land in such a state that fugitive dust emissions (including windblown dust or dust caused by vehicular traffic on the area) would violate conditions I.F or I.G of Part B of this permit. [PCC 17.16.050.B]

2. Vacant Lots and Open Spaces

   a. The Permittee shall not cause, suffer, allow, or permit a building or its appurtenances, or a building site, or a driveway, or a parking area, or a vacant lot or other open area to be constructed, used, altered, repaired, demolished, cleared, or leveled, or the earth to be moved or excavated, without taking reasonable precautions to limit excessive amounts of particulate matter from becoming airborne. Dust and other types of air contaminants shall be kept to a minimum by good modern practices such as using an approved dust suppressant or adhesive soil stabilizer, paving, covering, landscaping, continuous wetting, detouring, barring access, or other acceptable means [PCC 17.16.050.A & SIP Rule 7.5.A.2]

   b. The Permittee shall not leave any vacant lot, building site, parking area, or other open area in such a state after construction, alteration, clearing, leveling, or excavation that naturally induced wind blowing over the area causes a violation the standards in I.F or I.G of this Part B. Dust and other types of air contaminants shall be kept to a minimum by good modern practices such as landscaping, covering with gravel or vegetation, paving, or applying equivalently effective controls. [PCC 17.16.050.B & SIP Rule 7.5.B]

   c. No vacant lot, parking area, sales lot, or other open urban area shall be used by motor vehicles in such a manner that visible dust emissions induced by vehicular traffic on the area cause a violation of the standards in I.F or I.G of Part B. [PCC 17.16.050.C & SIP Rule 7.5.C]

3. Roads and Streets

   a. The Permittee shall not cause, suffer, allow or permit the use, repair, construction or reconstruction of a roadway or alley without taking reasonable precautions to prevent excessive amounts of particulate matter from becoming airborne. Dust and other particulates shall be kept to a minimum by employing temporary paving, dust suppressants, wetting down, detouring or by other reasonable means. [PCC 17.16.050.A & SIP Rule 7.5.A & B]

   b. The surfacing of roadways with asbestos tailings is prohibited [PCC 17.16.050.E & SIP Rule 7.5.E]

   c. No person shall cause, suffer, allow or permit transportation of materials likely to give rise to airborne dust without taking reasonable precautions, such as wetting, applying dust suppressants, or covering the load, to prevent particulate matter from becoming airborne. Earth or other material that is deposited by trucking or earth moving equipment shall be removed from paved streets by the person responsible for such deposits. [PCC 17.16.090.C]

4. Particulate Materials

   The Permittee shall not cause, suffer, allow, or permit crushing, screening, handling, transporting, or conveying of materials or other operations likely to result in significant amounts of airborne dust without taking reasonable precautions, such as the use of spray bars, wetting agents, dust suppressants, covering the load, and hoods to prevent excessive amounts of particulate matter from becoming airborne. [PCC 17.16.190.A & 30A.A through C]

5. Storage Piles

   The Permittee shall not cause, suffer, allow, or permit organic or inorganic dust producing material to be stacked, piled or otherwise stored without taking reasonable precautions such as chemical stabilization, wetting, or covering to prevent excessive amounts of particulate matter from becoming airborne. [PCC 17.16.130.A & SIP Rule 7.6.B]

B. Recordkeeping Requirements [PCC 17.12.190.A.4]

The Permittee shall maintain records of dates and types of control measures adopted pursuant to X.A through 5 of this section.

XIV. USE OF PAINTS [Locally Enforceable Conditions]

A. Emission Limits and Standards [PCC 17.12.190.A.1]

1. Surface Coating Operations

   a. Paint Booth Requirements (Enclosed surface coating operations)

      The Permittee shall not conduct any spray paint operation without minimizing organic solvent emissions. Such operations, other than architectural coating and spot painting, shall be conducted in an enclosed area equipped with controls containing no less than ninety-six percent of overspray. [PCC 17.16.200.C.1]

   b. Architectural Coatings

      The Permittee (or contractor) shall not employ, evaporate or dry any architectural coating containing photochemically reactive solvents (PRS) for industrial or commercial purposes, or thin or dilute any architectural coating with a PRS. A PRS shall be any solvent with an aggregate of more than 20% of its total volume composed of the chemical compounds as classified below, or which exceeds any of the percentage composition limitations as stated below. Whenever any organic solvents or any constituents of an organic solvent may be classified from its chemical structure into more than one of the groups of organic compounds described below, it shall be considered to be a member of the group having the least allowable percent of the total volume of solvents: [PCC 17.16.200.C.2.a]

      i. A combination of the following types of compounds having an olefinic or cyclo-olefinic type of unsaturation-hydrocarbons, alcohols, aldehydes, esters, ethers, or ketones: 5%.

ii. A combination of aromatic compounds with eight or more carbon atoms to the molecule, except ethylbenzene: *8%*.

iii. A combination of ethylbenzene, ketones having branched hydrocarbon structures, trichloroethylene or toluene: *20%*.

B. Monitoring Requirements [PCC 17.12.180.A.3]

1. Surface Coating Operations

a. The Permittee shall monitor the amount of volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) in each coating and solvent product used in all surface coating operations at the facility to include those surface coating operations contracted to vendors and used onsite.

b. The Permittee shall monitor the amount of each coating and solvent product used in surface coating operations at the facility during each calendar month. Onsite operations contracted to vendors, other than spot painting (e.g., touchup work), shall be included in the monthly totals.

C. Recordkeeping Requirements

1. Surface Coating Operations [PCC 17.12.180.A.4]

a. The Permittee shall maintain documentation demonstrating that enclosed surface coating operations meet the overspray control requirements in condition XI.A.1.a in this section by using filters that have a minimum ASHRAE arrestance rating of at least 96%, or an equivalent system which can be shown to meet the over-spray control requirement, and that the enclosure and controls are operated and maintained consistent with manufacturer's guidelines or good engineering practice.

b. The Permittee shall maintain a file of Material Safety Data Sheets (MSDS) or equivalent manufacturer's product data sheet for each coating and solvent product used at the facility to include coatings and solvents used by contracted vendors (for work other than spot painting).

c. Upon request of the control officer, the Permittee shall prepare a list of architectural coatings used at the facility. The list shall be made available to the control officer within 30 calendar days of the request and shall be accompanied by the Material Safety Data Sheets (MSDS) or equivalent manufacturer's product information and content sheet for each of the architectural coatings listed.

d. The Permittee shall maintain a record of the amounts of each coating and solvent product used during each calendar month (excluding spot painting conducted by vendors). Within 30 calendar days of the beginning of a new month, the Permittee shall sum the amounts of each coating and solvent products used during the previous month and record and clearly identify that entry in a log.

e. The files shall be retained for a minimum of five years and shall be made available to the control officer upon request.

XV. ABRASIVE BLASTING

A. Emission Limits and Standards [PCC 17.12.180.A.2]

Emissions from a sandblasting or other abrasive blasting operation shall be effectively controlled by applying water to suppress visible emissions (wet blasting), enclosing the operation, or use of other equivalently effective controls. [PCC 17.16.100]

B. Monitoring Requirements [PCC 17.12.180.A.3]

The Permittee shall monitor the type of control or control device used to minimize emissions from abrasive blasting operations. For the purpose of this condition, monitoring shall not be required for small commercial abrasive blasting cabinets which shall be considered insignificant activities, provided they are equipped with filtration control devices.

C. Recordkeeping Requirements [PCC 17.12.180.A.4]

The Permittee shall record the type of control or control device used to minimize emissions from each abrasive blasting operation. Such records shall be retained on site for a minimum of five years and shall be made available to the control officer upon request.

D. Testing Requirements

1. A certified Method 9 observer shall conduct a visual survey of visible emissions during abrasive blasting operations. The Permittee shall record the location observed, the name of the observer, date on which the observation was made, and the results of the observation.

2. If the observer sees a plume from an emission point that appears to exceed 20% opacity on an instantaneous basis, the observer shall take a six-minute Method 9 observation of the plume if possible.

3. If the six-minute opacity of the plume exceeds 20%, the Permittee shall do the following:

a. Adjust or repair the controls or equipment to reduce opacity to below 20%; and

b. Report it as an excess emission in accordance with XII.A of Part A of this permit.

4. If the six-minute opacity of the plume is less than 20%, the observer shall make a record of the following:

a. Date and time of the observation; and

b. The results of the Method 9 observation.

R012297

R012298

ATTACHMENT 1:
APPLICABLE REGULATIONS

Requirements Specifically Identified as Applicable:

Pima County State Implementation Plan (SIP):

Rule 301	Planning Construction, or Operating without a Permit
Rule 302	Non-Compliance with Applicable Standards
Rule 315	Roads and Streets
Rule 316	Particulate Materials
Rule 318	Vacant Lots and Open Spaces
Rule 321	Standards and Applicability & Table 321
Rule 343	Visibility Limiting Standard
Rule 344	Odor Limiting Standards

Code of Federal Regulations Title 40:

Part 60 Subpart	KKKK New Source Performance Standards for Stationary combustion Turbines
Part 60 Subpart	GG New Source Performance Standards for Stationary combustion Turbines
Part 60 Appendix A	Test Methods
Part 60 Appendix B	Performance Specifications
Part 63 Subpart ZZZZ	NESHAPS for Stationary Reciprocating Internal Combustion Engines
Part 63 Subpart Q	NESHAPS for Industrial Process Cooling Towers
Part 75	Continuous Emission Monitoring
Part 75 Appendix A	Specifications and Test Procedures
Part 75 Appendix B	Quality Assurance and Quality Control
Part 75 Appendix D	Optional SO2 Emissions Data Protocol for Gas Fired and Oil-Fired Units
Part 75 Appendix F	Conversion Procedures
Part 75 Appendix G	Determination of CO2 Emissions

Pima County Code (PCC) Title 17, Chapter 17.16:

17.12.060	Existing Source Emission Monitoring
17.16.020	Noncompliance with Applicable Standards
17.16.030	Odor Limiting Standards
17.16.040	Standards and Applicability (Includes NESHAP)
17.16.050	Visibility Limiting Standards
17.16.060	Fugitive Dust Producing Activities
17.16.080	Vacant Lots and Open Spaces
17.16.090	Roads and Streets
17.16.100	Particulate Materials
17.16.110	Storage Piles
17.16.130	Applicability
17.16.160	Standards of Performance for Fossil-Fuel Fired Steam Generators and General Fuel Burning Equipment
17.16.165	Standards of Performance for Fossil-Fuel Fired Industrial and Commercial Equipment
17.16.340	Standards of Performance for Stationary Rotating Machinery
17.16.400	Organic Solvents and other organic materials
17.16.430	Standards of Performance for Unclassified Sources

Installation Permit #1156 – October 14, 1981 by Arizona Department of Health Services

Attachment 2

ATTACHMENT 2:
EMISSIONS UNITS

1. Electric Utility Steam Generating Units – Fossil Fuel Fired Steam Generators

Equipment Number	Description	MFR/Model	Serial Number/ Design ID	Maximum Rated Capacity	Date of MFR Installation, or Reconstruction	Allowable Fuels			Applicability
						Gaseous Fuels	Liquid Fuels (Max % S Wt)	Solid Fuels	Regulated Emission Units (R18-2-A314)
1	Electric Utility Steam Generating Unit (EGU)	Combustion Engineering	10469	85 MW (Net) 850 MMBTU/hr	1973	Natural Gas & Landfill Gas	Fuel Oils No. 2 through No. 6	N/A	Yes
2	Electric Utility Steam Generating Unit (EGU)	Combustion Engineering	10470	85 MW (Net) 850 MMBTU/hr	1974	Natural Gas & Landfill Gas	Fuel Oils No. 2 through No. 6	N/A	Yes
3*	Electric Utility Steam Generating Unit (EGU)	Combustion Engineering	10485	110 MW (Net) 1100 MMBTU/hr	1981	Natural Gas & Landfill Gas	Fuel Oils No. 2 through No. 6	N/A	Yes
4*	Electric Utility Steam Generating Unit (EGU)	Combustion Engineering	10486	110 MW (Net) 1100 MMBTU/hr	1981	Natural Gas & Landfill Gas	N/A	N/A	Yes

II. EGU Fossil Fuel Fired Steam Generators – Installed and Certified Continuous Emissions/Opacity Monitoring Systems

Unit	Pollutant/ Parameter	Method	Range
11	Oxygen	Paramagnetic	0-21%
	NO_X	Chemiluminescence	0-800 ppm
	Fuel Flow - Gas	Differential Pressure (DP)	0-9000 lscfh
	Fuel Flow - Oil	Positive Displacement (PDP)	0-50000 lb/hr
12	Oxygen	Paramagnetic	0-21%
	NO_X	Chemiluminescence	0-400 ppm
	Fuel Flow - Gas	Differential Pressure (DP)	0-9000 lscfh
	Fuel Flow - Oil	Positive Displacement (PDP)	0-50000 lb/hr
13	Oxygen	Paramagnetic	0-21%
	NO_X	Chemiluminescence	0-400 ppm
	Fuel Flow - Gas	Differential Pressure (DP)	0-12000 lscfh
	Fuel Flow - Oil	Positive Displacement (PDP)	0-75000 lb/hr
	Oxygen	Paramagnetic	0-21%
14	Oxygen	Paramagnetic	0-21%
	NO_X	Chemiluminescence	0-400 ppm
	Fuel Flow – Gas	Differential Pressure (DP)	0-20,000 lscfh
	Mass Flow	Constant temperature anemometer thermal array	3.29 x 107 scfh
	Opacity	Electro-optical, double pass	0-100%

III. Cooling Towers

Equipment ID	Description	Serial Number	Make	Date of Manufacture, Installation, or Reconstruction
1E	Steam Unit Cooling Tower	FD90980	Fluor Products	1957
2D	Steam Unit Cooling Tower	FD92580	Fluor Products	1959
3D	Steam Unit Cooling Tower	663-3-10	Marley Co.	1961
4E	Steam Unit Cooling Tower	6645-12-36-3	Marley Co.	1964

IV. Stationary Rotating Machinery (Gas Turbines)

Equipment ID	Description	Capacity	Serial Number	Make	Fuels	Date of Manufacture, Installation, or
IGT1	Simple cycle gas turbine generating unit	24 MW Net	17A2088-1	Westinghouse	#2 Distillate Fuel Oil, or Natural Gas	1972
IGT2	Simple cycle gas turbine generating unit	24.5 MW Net	17A2086-1	Westinghouse	#2 Distillate Fuel Oil or Natural Gas	1972
IGT3	Simple cycle gas turbine generating unit	< 25 MW Net	To be submitted upon purchase	To be submitted upon purchase	Natural Gas Only	To be submitted upon purchase

V. Gas Turbine Starter ICE and Emergency Generators

Equipment ID	Description	Capacity	Serial Number	Make/ Model	Fuels	Date of Manufacture	Rule Applicability
EGEN1	NESHAP Emergency Generator	349 HP (260 kW)	9NR03701	Caterpillar/ 3306	Diesel	1999	NESHAP Subpart ZZZZ
EGEN2	NSPS Emergency Generator	636 HP (474 kW)	8CMAF6003ID	Kohler/ 400REOZDD	Diesel	2008	NSPS Subpart IIII
IGT1A	NESHAP Gas turbine starter engine	635 hp	772267-3	Cummings	Diesel	1972	NESHAP Subpart ZZZZ
IGT2A	NESHAP Gas turbine starter engine	635 hp	769853-3	Cummings	Diesel	1972	NESHAP Subpart ZZZZ

R012299

R012300

Attachment 7

VI. Reciprocating Internal Combustion Engines

Equipment ID	Description	Capacity	Serial Number	Make/ Model	Fuels	Date of Manufacture	Rule Applicability
RICE01	Reciprocating Internal Combustion Engine (RICE)	19 MW Net 154.5 MMBtu/hr	TBD*	TBD*	Natural Gas	est. 2017	NSPS Subpart JJJJ NESHAP Subpart ZZZZ
RICE02	Reciprocating Internal Combustion Engine (RICE)	19 MW Net 154.5 MMBtu/hr	TBD*	TBD*	Natural Gas	est. 2017	NSPS Subpart JJJJ NESHAP Subpart ZZZZ
RICE03	Reciprocating Internal Combustion Engine (RICE)	19 MW Net 154.5 MMBtu/hr	TBD*	TBD*	Natural Gas	est. 2017	NSPS Subpart JJJJ NESHAP Subpart ZZZZ
RICE04	Reciprocating Internal Combustion Engine (RICE)	19 MW Net 154.5 MMBtu/hr	TBD*	TBD*	Natural Gas	est. 2017	NSPS Subpart JJJJ NESHAP Subpart ZZZZ
RICE05	Reciprocating Internal Combustion Engine (RICE)	19 MW Net 154.5 MMBtu/hr	TBD*	TBD*	Natural Gas	est. 2017	NSPS Subpart JJJJ NESHAP Subpart ZZZZ
RICE06	Reciprocating Internal Combustion Engine (RICE)	19 MW Net 154.5 MMBtu/hr	TBD*	TBD*	Natural Gas	est. 2017	NSPS Subpart JJJJ NESHAP Subpart ZZZZ
RICE07	Reciprocating Internal Combustion Engine (RICE)	19 MW Net 154.5 MMBtu/hr	TBD*	TBD*	Natural Gas	est. 2017	NSPS Subpart JJJJ NESHAP Subpart ZZZZ
RICE08	Reciprocating Internal Combustion Engine (RICE)	19 MW Net 154.5 MMBtu/hr	TBD*	TBD*	Natural Gas	est. 2017	NSPS Subpart JJJJ NESHAP Subpart ZZZZ
RICE09	Reciprocating Internal Combustion Engine (RICE)	19 MW Net 154.5 MMBtu/hr	TBD*	TBD*	Natural Gas	est. 2017	NSPS Subpart JJJJ NESHAP Subpart ZZZZ
RICE10	Reciprocating Internal Combustion Engine (RICE)	19 MW Net 154.5 MMBtu/hr	TBD*	TBD*	Natural Gas	est. 2017	NSPS Subpart JJJJ NESHAP Subpart ZZZZ

* Make and model of these units to be determined

Attachment 1

ATTACHMENT 3:
INSIGNIFICANT ACTIVITIES

Equipment ID	Description	Capacity	Date of Manufacture, Installation, or Reconstruction
A6	Power Production - Flyash Latrine Vents	NA	NA
C21	Power Production - Rotary Car Dumper Latrine Vent/Septic System	NA	NA
C22	Power Production - Crusher Tower Latrine Vent/Septic System	NA	NA
CHEM1	Power Production - North 12,000 gal 93% Sulfuric Acid Storage Tank	NA	NA
CHEM2	Power Production - North 12,000 gal 50% Liquid NaOH Storage Tank	NA	NA
CHEM3	Power Production - North Water Treatment Chemical Storage Bins/Barrels	NA	NA
CHEM4	Power Production - North Cooling Tower Treatment Room	NA	NA
CHEM5	Power Production - North Boiler Water Treatment Area	NA	NA
CHEM6	Power Production - South 12,000 gal 93% Sulfuric Acid Storage Tank	NA	NA
CHEM7	Power Production - South Water Treatment Chemical Storage Bins/Barrels	NA	NA
CHEM8	Power Production - South Cooling Tower Treatment Room	NA	NA
CHEM9	Power Production - South Boiler Water Treatment Area	NA	NA
CHEM11	Power Production -Environmental Laboratory Latrine Vent/Septic System	NA	NA
CHEM12	Power Production - Environmental Laboratory Fume Hood	NA	NA
CHEM13	Power Production - Water Laboratory Fume Hood (2)	NA	NA
CHEM14	Power Production - Environmental Laboratory Heater	NA	NA
CHEM15	Power Production - Boiler Feedwater Storage Tanks (6)	NA	NA
FH1	Fuel Oil Storage Tank #1 – Vertical Fixed Roof AST	524,072 gal	1957
FH2	Fuel Oil Storage Tank #2 – Vertical Fixed Roof AST	524,072 gal	1958
FH3	Fuel Oil Storage Tank #3 – Vertical Fixed Cone Roof AST	756,084 gal	1961
FH5	Water Storage Tank #5 – Vertical Fixed Roof AST	3,034,858 gal	1971

Attachment 1

Equipment ID	Description	Capacity	Date of Manufacture, Installation, or Reconstruction
FH6	Fuel Oil Storage Tank #6 – Vertical Fixed Roof AST	3,034,858 gal	1971
FH7	Fuel Oil Storage Tank #7 – Vertical Fixed Roof AST	3,034,858 gal	1971
FH9	Power Production - Condensate Return Collection Sump Vents	NA	NA
FH11	Fuel Oil Storage Tank #11 – Vertical Fixed Roof AST	3,034,858 gal	1972
FH12	Fuel Oil Storage Tank #12 – Vertical Fixed Roof AST	3,034,858 gal	1972
FH13	Fuel Oil Storage Tank #13 – Vertical Fixed Roof AST	3,034,858 gal	1972
FH14	Power Production - Condensate Return Collection Sump Vents	NA	NA
FH15	Power Production - Fuel Oil Unloading/Transfer/Pumping and Piping Facilities	NA	NA
FH16	Power Production - Waste Oil Drums	NA	NA
GS9	General Shop - Furnace 75 kBTU	NA	NA
GS10	General Shop - Latrine Vents	NA	NA
GS11	General Shop Paint Booth	NA	NA
I5	Power Production - Power Block Latrine Vents	NA	NA
I6	Power Production - Engineering Building Latrine Vents	NA	NA
I7	Power Production - Power Block Used Oil Storage Drums	NA	NA
I8	Power Production - Power Block Battery Rooms	NA	NA
I9	Power Production - Common Facilities Battery Room	NA	NA
I11	Power Production - Mechanical Maintenance Flammable Storage cabinets	NA	NA
I12	Power Production - Switchyard Circuit Breakers/Transformers	NA	NA
I13	Lube Oil/Paint Storage Room	NA	NA
I14	Power Production - Maintenance Shop Welding Activities/Vents/ Solvent Tanks	NA	NA
I15	Electrical Shop Solvent Tank	NA	NA
I72	Power Production - #5 Fire/Dust Control Water Storage Tank 3,000,000 gal	NA	NA
I73	Power Production - Service Water Pressure/Storage Tank 150,000 gallons	NA	NA

Attachment 1

Equipment ID	Description	Capacity	Date of Manufacture, Installation, or Reconstruction
H6-21, WH1-2, GS1-8, TRAN4-12	Miscellaneous hot water and space heaters	Misc.	Misc.
I1A	Power Production - Unit #1 Boiler Blowdown Flashtank	NA	NA
I1B	Turbine lube oil vapor extractor	NA	NA
I1C	Generator bearing drain vapor extractor	NA	NA
I1D	Generator bearing drain vacuum pump	NA	NA
I1F	Power Production - North Turbine Lube Oil Storage Tank	NA	NA
I1G	Power Production - Unit #1 Fuel Gas Piping	NA	NA
I1H	Power Production - Unit #1 Fuel Gas Vents	NA	NA
I1I	Power Production - Unit #1 Boiler Safety Relief Valve Vents	NA	NA
I1J	Power Production - Unit #1 Steam/Drain Vents	NA	NA
I1K	Power Production - Unit #1 Main Transformer	NA	NA
I1L	Power Production - Unit #1 Auxiliary Transformer	NA	NA
I2A	Power Production - Unit #2 Boiler Blowdown Flashtank	NA	NA
I2B	Turbine lube oil vapor extractor	NA	NA
I2C	Generator bearing drain vapor extractor	NA	NA
I2E	Power Production - Unit #2 Fuel Gas Piping	NA	NA
I2F	Power Production - Unit #2 Fuel Gas Vents	NA	NA
I2G	Power Production - Unit #2 Boiler Safety Relief Valve Vents	NA	NA
I2H	Power Production - Unit #2 Steam/Drain Vents	NA	NA
I2I	Power Production - Unit #2 Main Transformer	NA	NA
I2J	Power Production - Unit #2 Auxiliary Transformer	NA	NA
I3A	Power Production - Unit #3 Boiler Blowdown Flashtank	NA	NA
I3B	Turbine lube oil vapor extractor	NA	NA
I3C	Generator bearing drain vapor extractor	NA	NA
I3E	Power Production - South Turbine Lube Oil Storage Tank	NA	NA
I3F	Power Production - Unit #3 Fuel Gas Piping	NA	NA
I3G	Power Production - Unit #3 Fuel Gas Vents	NA	NA
I3H	Power Production - Unit #3 Boiler Safety Relief Valve Vents	NA	NA
I3I	Power Production - Unit #3 Steam/Drain Vents	NA	NA

R012301

R012302

Attachment 1

Equipment ID	Description	Capacity	Date of Manufacture, Installation, or Reconstruction
B3	Power Production - Unit #3 Main Transformer	NA	NA
B3K	Power Production - Unit #3 Auxiliary Transformer	NA	NA
B4A	Power Production - Unit #4 Boiler Blowdown Flashtank	NA	NA
B4B	Turbine lube oil vapor extractor	NA	NA
B4C	Generator bearing drain vapor extractor - 6508-G-33	NA	NA
B4D	Generator bearing drain vacuum pump	NA	NA
B4F	Power Production - Unit #4 Fuel Gas Piping	NA	NA
B4G	Power Production - Unit #4 Fuel Gas Vents	NA	NA
B4H	Power Production - Unit #4 Boiler Safety Relief Valve Vents	NA	NA
B4I	Power Production - Unit #4 Steam/Drum Vents	NA	NA
B4J	Power Production - Unit #4 Main Transformer	NA	NA
B4K	Power Production - Unit #4 Auxiliary Transformer	NA	NA
EGT4B	Turbine lube oil vapor extractor	0.5 hp/1A/230V	NA
EGT2B	Turbine lube oil vapor extractor	0.5 hp/1A/230V	NA
OH1	Operating Headquarters - HVAC Cooling Tower	NA	NA
OH1	ERTF Paint Booth	NA	NA
OH1	ERTF Weld Shop - welding operations	NA	NA
OH1	Fabrication Weld Shop Paint Booth	NA	NA
OH1	Glove Lab Paint Booth	NA	NA
OH1	Operating Headquarters - Latune Vents	NA	NA
OH5	Operating Headquarters - Training Center Latrine Vents	NA	NA
OH6	Operating Headquarters - Trailer Latrine Vents	NA	NA
OH73	Operating Headquarters Tool Room Solvent Tank	NA	NA
SS1	Service Center - HVAC Cooling Tower	NA	NA
SS2	Service Center - Reproduction Equipment	NA	NA
SS4	Service Center - Latrine Vents	NA	NA
TRAN1	Transportation - New/Used Lubricating Oil Storage	NA	NA
TRAN13	Transportation - Latrine Vents	NA	NA
TRAN2	Transportation - Underground Diesel Storage Tank	15,000 gal	NA

Attachment 1

Equipment ID	Description	Capacity	Date of Manufacture, Installation, or Reconstruction
Tank 19	Transportation - Aboveground Diesel Storage Tank	10,000 gal	NA
Tank 1	Transportation - Underground Gasoline Storage Tank	15,000 gal	1989
TRAN16	Transportation Steam Cleaner	NA	NA
TRAN	Transportation Car Wash and three associated natural gas-fired water heaters	NA	NA
WH4	WH4 Warehouse - Latune Vents	NA	NA
WW1	Power Production - North Collection Sump-Boiler Blowdown	NA	NA
WW2	Power Production - South Collection Sump (2) - Raw Runoff Ash/Coal Area Washdown	NA	NA
WW3	Power Production - Bottom Ash Runoff Collection Sump	NA	NA
WW4	Power Production Plant Waste Room-Boiler Blowdown Demineralizer Regenerant	NA	NA
WW5	Power Production - Coal Pile Runoff Basin- Raw Runoff, Ash/Coal Area Washdown	NA	NA
WW6	Power Production - Evaporation Basin (3) - Treated Wastewater from Plant Waste/Coal Pile Runoff Basin	NA	NA
WW7	Power Production-Waste Water Treatment Latrine Vent/Septic System	NA	NA
WW8	WW2 Power Production - Waste Water Treatment 5,000 gal 93% Sulfuric Acid Tank	NA	NA
WW9	Power Production - Waste Water Treatment 5,000 gal 50% Liquid NaOH Tank	NA	NA
WW10	Power Production - Waste Water Treatment Clarifier Wastewater 140,000 gal	NA	NA
WW11	Power Production - Waste Water Treatment Scum Tank-Clarifier Scum for recycle 1170 gal	NA	NA
WW12	Power Production - Waste Water Treatment pH Adjustment Tank- Pretreated Wastewater 6766 gal	NA	NA
WW13	Power Production - Waste Water Treatment pH Adjustment Tank- Treated Wastewater 5000 gal	NA	NA
WW14	Power Production - Waste Water Treatment Chemical Mix Tank (2) - Alum 710 gal	NA	NA
WW15	Power Production - Waste Water Treatment Chemical Mix Tank (2) - Polymer 148 gal	NA	NA
NA	Compact Linear Fresnel Reflector – Solar Steam Generator System	NA	TBD

ATTACHMENT 4:
EMISSIONS DISCHARGE OPACITY LIMITING STANDARDS

PCC 17.16.040

Type of Source	Instantaneous Opacity Measurements			Maximum Allowable Average Opacity, %
	Required No. (For a Set)	Excluded No. (Highest Values)	N. to Use For Averaging	
Cold Diesel Engines[1]	25	0	25	60
Loaded Diesel Engines[2]	26	1	25	60
Other Sources[3]	25	0	25	20

[1] Applicable to the first 10 consecutive minutes after starting up a diesel engine.

[2] Applicable to a diesel engine being accelerated under load.

[3] Any source not otherwise specifically covered within this table, unless otherwise specifically covered in this permit.

ATTACHMENT 5:
PHASE II ACID RAIN PERMIT

I. STATEMENT OF BASIS

Statutory and Regulatory Authorities: In accordance with Arizona Revised Statutes, Title 49, Chapter 3, Article 2, Section 426 N, and Titles IV and V of the Clean Air Act, the Pima County Department of Environmental Quality issues this Phase II Acid Rain Permit pursuant to Section 17.12.365 of Title 17 of the Pima County Code.

II. SO_2 ALLOWANCE[1] ALLOCATIONS AND NO_x REQUIREMENTS FOR EACH AFFECTED UNIT

[40 CFR Part 73 Table 2]

A. UNIT 11

Year:	2012	2013	2014	2015	2016	2017	2018
Annual SO_2 Allowances	14 tons	14 tons	14 tons	14 tons	14 tons	14 tons	14 tons
NO_x Limits:	This unit is not subject to a NO_x limit under 40 CFR Part 76.						

B. UNIT 12

Year:	2012	2013	2014	2015	2016	2017	2018
Annual SO_2 Allowances	40 tons	40 tons	40 tons	40 tons	40 tons	40 tons	40 tons
NO_x Limits:	This unit is not subject to a NO_x limit under 40 CFR Part 76.						

C. UNIT 13

Year:	2012	2013	2014	2015	2016	2017	2018
Annual SO_2 Allowances	2 tons	2 tons	2 tons	2 tons	2 tons	2 tons	2 tons
NO_x Limits:	This unit is not subject to a NO_x limit under 40 CFR Part 76.						

D. UNIT 14

Year:	2012	2013	2014	2015	2016	2017	2018
Annual SO_2 Allowances	2805 tons	2805 tons	2805 tons	2805 tons	2805 tons	2805 tons	2805 tons
NO_x Limits:	Pursuant to 40 CFR Part 76, the Pima County Department of Environmental Quality approves a NO_x emission limitation for UNIT 14. This unit's annual average NO_x emission rate for each year, determined in accordance with 40 CFR Part 75, shall not exceed the applicable emission limitation, under 40 CFR Part 76.7(a)(2), of 0.46 lb/MMBTU for wall-fired boilers. In addition, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.						

As defined under 40 CFR §72.2, "Allowance" means an authorization by the Administrator under the Acid Rain Program to emit up to one ton of sulfur dioxide during or after a specified calendar year. The number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitate a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR 72.84).

R012303

R012304

III. ACID RAIN PERMIT APPLICATION

The Permittee, and any other owners or operators of the units at this facility, shall comply with the requirements contained in the two attached acid rain permit applications. These applications are:

A. Phase II Permit Application (OMB No. 2060-0258) signed by the Designated Representative on 12/12/97.

B. Phase II NO_x Compliance Plan (OMB No. 2060-0258) signed by the Designated Representative on 12/15/97.

ATTACHMENT 6:
ALTERNATE OPERATING SCENARIO #1

I. APPLICABILITY – 40 CFR 60 Subpart KKKK

This alternate operating scenario #1 shall only apply to the turbine that will be identified as IGT3 upon purchase should the applicability date of IGT3 be subject to 40 CFR 60 Subpart KKKK. TEP-IGS shall notify PDEQ upon purchasing the turbine. The notification shall include all reporting requirements that are identified in this attachment.

II. GENERAL PROVISIONS

The following requirements apply to the operation, maintenance, recordkeeping and testing of Unit IGT3 and its associated monitoring systems in accordance with 40 CFR Part 60, Subpart A – General Provisions. These requirements are in addition to any applicable requirements in the General Provisions in Part A of this permit, unless Attachment 6 is more stringent.

A. Mailing Address

All reports, reports, applications, submittals, and other communications to the Administrator and Control Officer pursuant to 40 CFR Part 60 shall be submitted in duplicate to the Administrator and Control Officer at the following addresses: [40 CFR 60.4(a)]

Director U.S. Environmental Protection Agency 75 Hawthorne Street San Francisco, CA 94105	Director Pima County Department of Environmental Quality 33 North Stone Avenue, Suite 700 Tucson, AZ 85701

B. Notification and Recordkeeping

1. The Permittee shall furnish the Control Officer written notification as follows. [40 CFR 60.7(a)]

   a. A notification of the date of construction of Unit IGT3 is commenced postmarked no later than 30 days after such date (date of construction). [40 CFR 60.7(a)(1)]

   b. A notification of the actual date of initial startup of Unit IGT3 postmarked within 15 days of after such date (date of initial startup). [40 CFR 60.7(a)(3)]

   c. A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Control Officer may request additional relevant information subsequent to this notice. [40 CFR 60.7(a)(4)]

   d. A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with 40 CFR 60.13(c) postmarked not less than 30 days prior to such date. [40 CFR 60.7(a)(5)]

   e. A notification of the anticipated date for conducting the opacity observations required by 40 CFR 60.11(e)(1). The notification shall also include, if appropriate, a request for the Administrator to Provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date. [40 CFR 60.7(a)(6)]

f. A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR 60.8 in lieu of Method 9 observation data as allowed by 40 CFR 60.11(e)(5). This notification shall be postmarked not less than 30 days prior to the date of the performance test. [40 CFR 60.7(a)(9)]

2. The Permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative. [40 CFR 60.7(b)]

3. The Permittee shall submit excess emissions and monitoring systems performance reports and/or summary report form to the Control Officer semi-annually, except when: more frequent reporting is specifically required by an applicable subpart; or the Control Officer, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information: [40 CFR 60.7(c), 40 CFR 60.43(a); 40 CFR 60.4375; & PCC 1.9.12.b.ii.B]

a. The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions and the process operating time during the reporting period. [40 CFR 60.7(c)(1)]

b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted. [40 CFR 60.7(c)(2)]

c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments. [40 CFR 60.7(c)(3)]

d. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report. [40 CFR 60.7(c)(4)]

4. The summary report form submitted by the Permittee shall contain the information and be in the format shown in 40 CFR 60.7(d) Figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at IGT3. [40 CFR 60.7(d)]

a. If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in II.B.3 of Attachment 6 need not be submitted unless requested by the Administrator. [40 CFR 60.7(d)(1)]

b. If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in II.B.3 of Attachment 6 shall both be submitted. [40 CFR 60.7(d)(2)]

5. The Permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows: [40 CFR 60.7(f)]

a. If the Permittee is required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS sub-hourly measurements as required in II.B.5 of Attachment 6, the Permittee shall retain the most recent consecutive three averaging periods of sub-hourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard. [40 CFR 60.7(f)(1)]

b. If the Permittee is required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS sub-hourly measurements as required under II.B.5 of Attachment 6 the Permittee shall retain all sub-hourly measurements for the most recent reporting period. The sub-hourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator. [40 CFR 60.7(f)(2)]

c. The Administrator or Control Officer, upon notification to the source, may require the Permittee to maintain all measurements as required by II.B.5 of Attachment 6, if the Administrator or Control Officer determines these records are required to more accurately assess the compliance status of the affected source. [40 CFR 60.7(f)(3)]

C. **Performance Tests**

Within 60 days after achieving the maximum production rate at which IGT3 will be operated, but not later than 180 days after initial startup of IGT3 and at such other times as may be required by the Control Officer under section 114 of the Act, the Permittee shall conduct emissions performance test(s) for NO_x and SO_2, and furnish the Control Officer a written report of the results of such performance test(s). [40 CFR 60.8(a)]

D. **Compliance with Standards and Maintenance Requirements**

1. At all times, including periods of startup, shutdown, and malfunction, the Permittee shall to the extent practicable, maintain and operate IGT3 including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Control Officer which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. [40 CFR 60.11(d)]

2. For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of any standard in 40 CFR Part 60, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. [40 CFR 60.11(g)]

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E. Circumvention

The Permittee shall not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission, which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with opacity standard or with a standard, which is based on the concentration of a pollutant in the gases discharged to the atmosphere. [40 CFR 60.12]

F. General Notification and Reporting Requirements

The Permittee shall comply with the "General Notification and Reporting Requirements" found in 40 CFR 60.19. [40 CFR 60.19]

III SPECIFIC CONDITIONS

A. Operational Limitations

The Permittee shall not cause or allow the combustion of any fuel in Unit IGT3 other than pipeline quality natural gas. [PCC 17.52.330.A.3]

B. Nitrogen Oxide

1. Emission Limitations/Standards [PCC 17.52.330.A.3]

a. The Permittee shall not allow the NO_x concentration to exceed 25 ppm at 15 percent O2 or 1.2 pound per megawatt-hour as determined by the NO_x and diluent CEMS based on a 4-hour rolling average. [40 CFR 60.4320 Table 1, 40 CFR 60.4380(b)(1)]

b. The Permittee shall not allow the total combined emissions of NO_x from Unit IGT3 to equal or exceed 90 tons per year, calculated as a 12-month rolling total. [PCC 17.52.330.B]

[Material Permit Condition]

2. Air Pollution Control Equipment

The Permittee must operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing NO_x emissions at all times including during startup, shutdown, and malfunction. [40 CFR 60.11(d)]

[Material Permit Condition]

3. Monitoring, Recordkeeping and Reporting Requirements [PCC 17.52.330.A.3 & A.5]

a. The Permittee must install and certify each NO_x diluent CEMS according to 40 CFR 60 Appendix B, Performance Specification 2 (PS 2), except the 7-day calibration drift is based on unit operating days, not calendar days and the relative accuracy test audit (RATA) shall be performed in lb/MMBtu basis. [40 CFR 60.4345(a)]

[Material Permit Condition]

b. The Permittee shall demonstrate compliance with the NO_x emission limitation in III.B.1.a of Attachment 3 as follows:

i. Install, calibrate, maintain, and operate a continuous monitoring system (CMS) to monitor and record the fuel consumption and the ratio of water to fuel being fired in Unit IGT3 when burning a fuel that requires water injection for compliance; or [40 CFR 60.4335(a)]

ii. Alternatively, the Permittee shall in accordance with III.E.1 of Attachment 3. install, certify, maintain and operate a continuous emission monitoring system (CEMS) consisting of a NO_x monitor, and a diluent gas (CO_2 or O_2) monitor, to determine the hourly NO_x emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and [40 CFR 60.4335(a)(1)]

iii. If complying with the output-based standard, the Permittee shall install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to IGT3; and [40 CFR 60.4335(a)(2)]

iv. If complying with the output-based standard, the Permittee shall install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of IGT3 in megawatt hours. [40 CFR 60.4335(a)(3)]

c. The Permittee shall install, calibrate, maintain and operate each watt meter, steam flow meter and each pressure or temperature measurement device according to manufacturer's instructions. [40 CFR 60.4345(g)]

d. Annual NO_x Emission Limit

To demonstrate compliance with the annual NO_x emission limit in III.B.1.b of Attachment 3, the Permittee shall comply with the continuous emission system monitoring, recordkeeping and reporting provisions in III.E.2 of Attachment 6.

4. Performance Testing [PCC 17.52.330.A.3]

a. The Permittee shall perform the initial performance test as required by 40 CFR 60.8: [40 CFR 60.4340]

b. The Permittee shall conduct annual performance tests (no more than 14 calendar months following the previous performance test). [40 CFR 60.4340(a)]

c. The Permittee shall use EPA Method 7E or EPA Method 20 for III.B.1.a of Attachment 3. For units complying with the output based standard, the Permittee shall concurrently measure the stack gas flow rate using EPA Methods 1 and 2, and measure and record the electrical and thermal output from IGT3. Then, use the following equation to calculate the NO_x emission rate:

$$E = \frac{1.194 \times 10^{-7} \times (NO_x)_c \times Q_{std}}{P}$$

where

E = NO_x emission rate, in lb/MWh

1.194×10^{-7} = conversion constant, in lb/ dscf-ppm

$(NO_x)_c$ = average NO_x concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/ hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to 40 CFR 60.4350(h)(2).

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d. The Permittee shall conduct NO_x emission performance test in accordance with 40 CFR 60.4400 or 40 CFR 60.4405.

C. Sulfur Dioxide

1. Emission Limitations/Standards

a. The Permittee shall not burn in Unit IGT3, any fuel that contains sulfur in excess of 0.060 pounds SO_2 per million British thermal unit (lb of SO_2/MMBtu) heat input.
[40 CFR 60.4365][PCC 17.12.300.B]
[Material Permit Condition]

b. The Permittee shall not allow the total combined emissions of SO_2 from Unit IGT3 to equal or exceed 40 tons per year, calculated as a 12-month rolling total. [PCC 17.12.300.B]
[Material Permit Condition]

2. Monitoring, Recordkeeping and Reporting Requirements [PCC 17.12.180.A.3, A.4 & A.5]

a. The Permittee shall be exempted from monitoring the total sulfur content of fuel combusted in IGT3, by keeping readily available for inspection, a paper or electronic record of a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for natural gas use is 20 grains of sulfur or less per 100 standard cubic feet and has potential sulfur emissions of less than less than 26 ng SO_2 /J (0.060 lb SO_2 /MMBtu) heat input. [40 CFR §60.4365(a)]

b. To demonstrate compliance with III.C.1.b of Attachment 6, the Permittee shall comply with the continuous emission monitoring, recordkeeping, and reporting requirements in III.E.2 of Attachment 6.

D. Carbon Monoxide

1. Emission Limitations/Standards

The Permittee shall not allow the total combined emissions of carbon monoxide (CO) from IGT3 to equal or exceed 100 tons per year, calculated as a 12-month rolling total. [PCC 17.12.300.B]
[Material Permit Condition]

2. Monitoring, Recordkeeping and Reporting Requirements [PCC 17.12.180.A.3, A.4 & A.5]

a. The Permittee shall install, calibrate, maintain and operate and quality assure a Continuous Emission Monitoring System (CEMS) consisting of CO and O_2 or CO_2 monitors for measuring CO emissions and diluent from IGT3. [Material Permit Condition]

b. The Permittee shall install, calibrate, maintain and operate the in-line fuel flowmeter monitoring systems for determining the natural gas input rate to IGT3 for each operating hour according to the manufacturer's instructions. [40 CFR 60.4345(a)]
[Material Permit Condition]

c. To demonstrate compliance with the annual CO emission limit in III.D.1 of Attachment 6, the Permittee shall comply with the CEMS monitoring, recordkeeping, and reporting requirements in Condition III.E.2 of Attachment 3.

E. Continuous Emissions Monitoring Systems (CEMS) [40 CFR §60.13, ACT 17.12.050.B.5]

1. New Source Performance Standards for Continuous Emission Monitoring Systems

To demonstrate compliance with III.B.1.a of Attachment 6 the Permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) and data acquisition handling system (DAHS) to calculate a four hour rolling average NO_x emission rate.

a. The Permittee shall comply with the following requirements in the General Provisions of 40 CFR 60 for each CEMS unit installed:

i. The CEMS and DAHS monitoring and recording devices shall be installed and operational prior to conducting initial performance test. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.
[40 CFR 60.13(d)]

ii. The Permittee shall automatically check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span must, as a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification in 40 CFR, Part 60, Appendix B. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. [40 CFR 60.13(d)(1)]

iii. Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under II.B.5 of Attachment 6, the CEMS shall be in continuous operation and shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. [40 CFR 60.13(e) & (e)(2)]

iv. The CEMS devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of 40 CFR 60 (III.E.1.b of Attachment 3) shall be used.
[40 CFR 60.13(f)]

v. The Permittee shall reduce all data to 1-hour averages as defined in 40 CFR 60.2. 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed under III.E.1.a.v of Attachment 6. The data may be recorded in reduced or non-reduced form (e.g., ppm pollutant and percent O2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used to specify the emission limit. [40 CFR 60.13(h)]

vi. The Permittee shall meet the notification and recordkeeping requirements in II.B.1.d and II.B.5 of Attachment 6.

b. The Permittee shall comply with the following requirements in the Performance Specifications of 40 CFR 60 Appendix B, for each CEMS unit installed.

i. The CEMS installation and measurement location specification shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.1.

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ii. Project preparation shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 3 & 8.2.

iii. Calibration drift test procedure shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.3.

iv. Relative accuracy test procedure shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 3 & 8.4.

v. Reporting requirements shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.5.

vi. Analytical procedures shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 11.0.

vii. Calculation and data analysis shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 12.0.

viii. Method performance shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 13.0.

ix. Alternative Procedures shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 16.0.

x. References are located in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 17.0.

xi. Tables, Diagrams, Flowcharts, and Validation data necessary for NO_x CEMS testing are located in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 18.0.

xii. Specifications and test procedures for O_2 and CO_2 CEMS in Stationary Systems shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 3.

xiii. Specifications and Test Procedures for CO CEMS in Stationary Sources shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 4.

c. The Permittee shall maintain and operate each CEMS unit in accordance with the following:

i. As specified in III.E.1.a.iii of Attachment 3, during each full unit operating hour, both the NO_x monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point shall be obtained with each monitor for each quadrant of the hour in which a unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_x emission rate for the hour. [40 CFR 60.4345(b)]

ii. All CEMS data must be reduced to hourly averages as specified III.E.1.a.v of Attachment 3. [40 CFR 60.4350(a)]

iii. For each unit operating hour in which a valid hourly average, as described in III.E.1.c.i of Attachment 3, is obtained for both NO_x and diluent monitors, the DAHS must calculate and record the hourly NO_x emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in Appendix A of 40 CFR Part 60. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations. [40 CFR 60.4350(g)]

iv. Correction of measured NO_x concentrations to 15 percent O_2 is not allowed. [40 CFR 60.4350(f)]

v. The Permittee shall reduce all required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data to hourly averages. [40 CFR 60.4350(c)]

vi. The Permittee shall calculate the hourly average NO_x emission rates, in units of either ppm (parts per million) for units complying with the concentration limit or in pounds per megawatt hour (lb/MWh) for units complying with the output based standard by using the simple cycle operation equation below: [40 CFR 60.4350(d)]

$$E = \frac{(NO_x)_h x (HI)_h}{P} \qquad \text{(Equation 1)}$$

E = hourly NO_x emission rate, in lb/MWh.

$(NO_x)_h$ = hourly NO_x emission rate, in lb/MMBtu.

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the Fuel flow meter(s), e.g., calculated using Equation D-15a in Appendix D to 40 CFR Part 75.

P = gross energy output of the combustion turbine in MW.

vii. The Permittee shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in III.E.3.a, III.E.3.b and III.E.3.c. [40 CFR 60.4345(a)]

2. Monitoring, Recordkeeping, and Reporting Requirements for Annual NO_x, SO_2 and CO Emission Limits. [PCC 11.11.2(b)(2)(a) & 11.4.3 & 11.5]

a. For the purpose of compliance demonstration with annual NO_x and CO emission limits, the Permittee shall utilize the NO_x, CO, diluent CEMS on Unit IGT3 in conjunction with the Data Acquisition and Handling System (DAHS) and fuel flow rate monitoring systems. A default value for SO_2 concentration will be calculated using equation 3 below. The DAHS will calculate emissions of NO_x, SO_2 and CO in pounds per hour (lb/hr), tons per month, and tons per year, calculated monthly as a 12-month rolling total. The Permittee shall use the procedures in Method 19 of 40 CFR 60 Appendix A as applicable to calculate NO_x, and CO mass emission rates.

b. The Permittee shall calculate SO_2 mass emission rates for Unit IGT3 using Equation 3 and 3A below:

$$ER = \left[\frac{Y_a}{Y_{8000}}\right] \times 10^6 \times \left[\frac{Y_{8000}}{GCV}\right] \qquad \text{(Equation 3)}$$

ER = Default SO_2 emission rate for natural gas combustion, lb/mmBtu

S_{fuel} = Total sulfur content of the natural gas from a valid purchase agreement, tariff agreement, or sampling, gr/100 scf

GCV = Gross calorific value of the natural gas from a valid purchase agreement, tariff agreement, or sampling, Btu/100 scf

7,000 = Conversion of grains/100 scf to lb/100 scf

10^6 = Conversion factor (lbs/MMBtu)

$SO_{2\ mss}$ = ER x HI_{mss} where: (Equation 3A)

$SO_{2\ mss}$ = Hourly mass emission rate of SO_2, lb/hr

ER = SO_2 default emission rate of 0.06 lbs/MMBtu

HI rate = Hourly heat input rate, MMBtu/hr

e. A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for NO_X, CO, and diluent concentration or heat input rate.

d. During CEMS system downtime, the Permittee shall implement the missing data procedures for NO_X and CO shown in 40 CFR Part 75 Subpart D – Missing Data Substitution Procedures

e. Each calendar month during which the combined 12-month rolling total for the NO_X emission rate from Unit IGT3 exceeds 40 tons shall constitute an exceedance. Exceedances shall be reported to the Control Officer in accordance with XI.A of Part A.

f. Each calendar month during which the combined 12-month rolling total for the SO_2 emission rate from Unit IGT3, exceeds 40 tons shall constitute an exceedance. Exceedances shall be reported to the Control Officer in accordance with XI.A of Part A.

g. Each calendar month during which the combined 12-month rolling total for the CO emission rate from Unit IGT3, exceeds 100 tons shall constitute an exceedance. Exceedances shall be reported to the Control Officer in accordance with XI.A of Part A.

h. Each individual day and 12-month rolling total for NO_X, SO_2, and CO emission rates in the reporting period shall be included in the semiannual compliance certification required by VII of Part A.

i. Quality Assurance Requirements for Natural Gas Fuel Flow meters

(A). Each transmitter or transducer shall be calibrated by equipment that has a current certificate of traceability to NIST standards at least once every four calendar quarters in which a unit operated on natural gas for 168 hours or more during each quarter but not less than once every three years. The Permittee shall check the calibration of each transmitter or transducer by comparing its readings to that of the NIST traceable equipment at least once at the following levels: the zero-level, and at least two other upscale levels (e.g., "mid" and "high"), such that the full range of transmitter or transducer readings corresponding to normal unit operation is represented.

(B). The Permittee shall calculate the accuracy of each transmitter or transducer at each level tested, using the following equation:

$$ACC = \frac{|R-T|}{FS} \times 100 \text{ Equation 4}$$

Where:

C = Accuracy of the transmitter or transducer as a percentage of full-scale.

R = Reading of the NIST traceable reference value (in milliamperes, inches of water, psi, or degrees).

T = Reading of the transmitter or transducer being tested (in milliamperes, inches of water, psi, or degrees, consistent with the units of measure of the NIST traceable reference value).

FS = Full-scale range of the transmitter or transducer being tested (in milliamperes, inches of water, psi, or degrees, consistent with the units of measure of the NIST traceable reference value).

(C). If each transmitter or transducer meets an accuracy of ± 1.0 percent of its full-scale range at each level tested, the fuel flow meter accuracy of 2.0 percent is considered to be met at all levels. If however, one or more of the transmitters or transducers does not meet an accuracy of ± 1.0 percent of full-scale at a particular level, then the Permittee may demonstrate that the fuel flow meter meets the total accuracy specification of 2.0 percent at that level by using one of the following alternative methods. If, at a particular level, the sum of the individual accuracies of the three transducers is less than or equal to 4.0 percent, the fuel flow meter accuracy specification of 2.0 percent is considered to be met for that level. Or, if at a particular level, the total fuel flow meter accuracy is 2.0 percent or less, when calculated in accordance with Part 1 of American Gas Association Report No. 3, General Equations and Uncertainty Guidelines, the flow meter accuracy requirement is considered to be met for that level.

(D). If during a transmitter or transducer accuracy test the flow meter accuracy specification of 2.0 percent is not met at any of the levels tested, the Permittee shall repair or replace the transmitter(s) or transducer(s) as necessary until the flow meter accuracy specification has been achieved at all levels. (Note that only transmitters or transducers which are repaired or replaced need to be re-tested; however, the re-testing is required at all three measurement levels to ensure that the flow meter accuracy specification is met at each level).

(E). For orifice, nozzles, and venturi type flow meters, the Permittee shall perform a primary element inspection for damage and corrosion at least once every 12 calendar quarters in which a unit operated on natural gas for 168 hours or more during each quarter but not less than once during the term of this permit. If damage and/or corrosion are found, the Permittee shall replace the flow meter or restore the damaged or corroded flow meter to "as new" condition.

(F). The Permittee shall log in ink, or in an electronic format the date that the calibration and inspection was conducted, the results of the calibration or inspection, and corrective action taken if needed.

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ATTACHMENT 7:
ALTERNATE OPERATING SCENARIO #2

I. APPLICABILITY – 40 CFR 60 Subpart GG

This alternate operating scenario #2 shall only apply to the turbine that will be identified as IGT3 upon purchase should the applicability date of IGT3 be subject to 40 CFR 60 Subpart GG. TEP-RGS shall notify PDEQ upon purchasing the turbine. The notification shall include all reporting requirements that are identified in this attachment.

II. GENERAL PROVISIONS

The following requirements apply to the operation, maintenance, recordkeeping and testing of Unit IGT3 and its associated monitoring systems in accordance with 40 CFR Part 60, Subpart A – General Provisions. These requirements are in addition to any applicable requirements in the General Provisions in Part A of this permit, unless Attachment 7 is more stringent.

A. Mailing Address

All requests, reports, applications, submittals, and other communications to the Administrator and Control Officer pursuant to 40 CFR Part 60 shall be submitted in duplicate to the Administrator and Control Officer at the following addresses. [40 CFR 60.4(a)]

Director
U.S. EPA Region IX
75 Hawthorne Street
San Francisco, CA 94105

Air Division Director
Pima County Department of Environmental Quality
33 North Stone Avenue, Suite 700
Tucson, AZ 85701

B. Notification and Recordkeeping

1. The Permittee shall furnish the Control Officer written notification as follows: [40 CFR 60.7(a)]

   a. A notification of the date of construction of Unit IGT3 is commenced postmarked no later than 30 days after such date (date of construction). [40 CFR 60.7(a)(1)]

   b. A notification of the actual date of initial startup of Unit IGT3 postmarked within 15 days of after such date (date of initial startup). [40 CFR 60.7(a)(3)]

   c. A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Control Officer may request additional relevant information subsequent to this notice. [40 CFR 60.7(a)(4)]

   d. A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with 40 CFR 60.13(c) postmarked not less than 30 days prior to such date. [40 CFR 60.7(a)(5)]

   e. A notification of the anticipated date for conducting the opacity observations required by 40 CFR 60.11(e)(1). The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date. [40 CFR 60.7(a)(6)]

   f. A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR 60.8 in lieu of Method 9 observation data as allowed by 40 CFR 60.11(e)(5). This notification shall be postmarked not less than 30 days prior to the date of the performance test. [40 CFR 60.7(a)(7)]

2. The Permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative. [40 CFR 60.7(b)]

3. The Permittee shall submit excess emissions and monitoring systems performance reports and/or summary report form to the Control Officer semi-annually, except where more frequent reporting is specifically required by an applicable subpart, or the Control Officer, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information: [40 CFR 60.7(c) & PCC 17.12.040.B]

   a. The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions and the process operating time during the reporting period. [40 CFR 60.7(c)(1)]

   b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted. [40 CFR 60.7(c)(2)]

   c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments. [40 CFR 60.7(c)(3)]

   d. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report [40 CFR 60.7(c)(4)]

4. The summary report form submitted by the Permittee shall contain the information and be in the format shown in 40 CFR 60.7(d) Figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at IGT3. [40 CFR 60.7(d)]

   a. If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in II.B.3 of Attachment 4 need not be submitted unless requested by the Administrator. [40 CFR 60.7(d)(1)]

   b. If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in II.B.3 of Attachment 7 shall both be submitted. [40 CFR 60.7(d)(2)]

5. The Permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows: [40 CFR 60.7(f)]

   a. If the Permittee is required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required in II.B.5 of Attachment 7, the Permittee shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard. [40 CFR 60.7(f)(1)]

   b. If the Permittee is required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under II.B.5 of Attachment 7 the Permittee shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator. [40 CFR 60.7(f)(2)]

   c. The Administrator or Control Officer, upon notification to the source, may require the Permittee to maintain all measurements as required by II.B.5 of Attachment 7, if the Administrator or Control Officer determines these records are required to more accurately assess the compliance status of the affected source. [40 CFR 60.7(f)(3)]

C. **Performance Tests**

Within 60 days after achieving the maximum production rate at which IGT3 will be operated, but not later than 180 days after initial startup of IGT3 and at such other times as may be required by the Control Officer under section 114 of the Act, the Permittee shall conduct emissions performance test(s) for NO_x and SO_2, and furnish the Control Officer a written report of the results of such performance test(s). [40 CFR 60.8(a)]

D. **Compliance with Standards and Maintenance Requirements**

At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate IGT3 including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Control Officer which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

1. For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of any standard in 40 CFR Part 60, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. [40 CFR 60.11(g)]

E. **Circumvention**

The Permittee shall not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission, which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with opacity standard or with a standard, which is based on the concentration of a pollutant in the gases discharged to the atmosphere. [40 CFR 60.12]

F. **General Notification and Reporting Requirements**

The Permittee shall comply with the "General Notification and Reporting Requirements" found in 40 CFR 60.19. [40 CFR 60.19]

III SPECIFIC CONDITIONS

A. **Operational Limitations**

The Permittee shall not cause or allow the combustion of any fuel in Unit IGT3 other than pipeline quality natural gas. [PCC 17.11.130 B]

B. **Nitrogen Oxide**

1. **Emission Limitations/Standards** [PCC 17.11.130 A 2]

   a. On and after the date of the performance test required by II.C of Attachment 7 is completed, the Permittee shall not cause to be discharged into the atmosphere from Unit IGT3 any gases which contain nitrogen oxides (NO_x) in excess of [40 CFR 60.332(a)(1) & 40 CFR 60.4320(a)] **[Material Permit Condition]**

$$STD = 0.0075\left(\frac{14.4}{Y}\right) + F$$

   Where,

   STD = allowable ISO corrected (if required as given in 40 CFR 60.335(b)(1)) NO_x emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

   Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

   F = NO_x emission allowance for fuel-bound nitrogen = 0. For Gas Turbine Units IGT3, STD = 75 ppmv at 15% oxygen

   b. The Permittee shall not allow the total combined emissions of nitrogen oxides from Unit IGT3 to equal or exceed 40 tons per year, calculated as a 12-month rolling total. [PCC 17.11.130 B] **[Material Permit Condition]**

2. **Air Pollution Control Equipment**

At all times, including during startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate Unit IGT3 including associated air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing NO_x emissions. [40 CFR 60.11(d)] [PCC 17.11.130 A 2] **[Material Permit Condition]**

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3. **Monitoring, Recordkeeping and Reporting Requirements** [PCT 17.12 (40 A.A.4 & A.5)]

a. The Permittee shall install, certify, maintain, operate and quality-assure Continuous Emission Monitoring Systems (CEMS) consisting of NO_x and O_2 (or CO_2) monitors for measuring NO_x emissions from Gas Turbine Unit IGT3. [PCT 17.12 (40 A.5)]
[Material Permit Conditions]

b. The Permittee shall install, calibrate, maintain, and operate fuel flow rate monitoring systems for determining the natural gas input rate to gas turbine unit IGT3 for each operating hour. The fuel flow rate monitoring system shall be calibrated and quality-assured in accordance with III.E.2.i of Attachment 4 [PCT 17.12 (40 A.5)]
[Material Permit Condition]

c. New Source Performance Standards (NSPS) Provisions

The Permittee shall comply with the following requirements contained in 40 CFR Part 60 Subpart GG as amended on July 8, 2004.

i. The Permittee shall comply with the NO_x emission limitation in III.B.1.a of Attachment 7 by using one of the following methods:

(A) Install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in Unit IGT3. [40 CFR 60.334(a)]

(B) Utilize the CEMS required by III.B.3.a of Attachment 4 and demonstrate compliance in accordance with III.B.3.c iii of Attachment 4. [40 CFR 60.334(a)]

ii. If the Permittee elects to demonstrate compliance with III.B.1.a. of Attachment 4 by continuously monitoring the water to fuel ratio as provided by III.B.3.c.i.(A) of Attachment 4, the following requirements shall apply:

(A) The water to fuel ratio in III.B.3.c.i.(A) of Attachment 4 shall be monitored during the performance test required under 40 CFR 60.8 to establish acceptable values and ranges. The Permittee may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The Permittee shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_x emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. [40 CFR 60.334(a)]

(B) The Permittee shall submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). Excess emissions shall be reported for all periods of Unit IGT3 operation, including startup, shutdown and malfunction. Excess emissions and monitor downtime that shall be reported are defined as follows: [40 CFR 60.334(c)(1)(i)]

(1) An excess emission shall be any unit operating hour for which the average water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable water to fuel ratio needed to demonstrate compliance with III.B.1.a of Attachment 7, as established during the performance test required in 40 CFR 60.8. Any unit operating hour in which no water is injected into the turbine shall also be considered an excess emission.

(2) A period of monitor downtime shall be any unit operating hour in which water is injected into the turbine, but the essential parametric data needed to determine the water to fuel ratio are unavailable or invalid.

(3) Each report shall include the average water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity) and gas turbine load. The Permittee is not required to report ambient conditions if opting to use the worst case ISO correction factor as specified in 40 CFR60.334(b)(3)(iii).

iii. If the Permittee elects to demonstrate compliance with III.B.1.a. of Attachment 7 using CEMS as provided by III.B.3.c (i)(B) of Attachment 4, the following requirements shall apply:

(A) The NO_x and diluent CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to Performance Specification 2 and 3 (for diluent) of 40 CFR Part 60, Appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. [40 CFR 60.334(b)(1)]

(2) The NO_x and diluent CEMS on Unit IGT3 shall be installed and operational prior to conducting performance tests as required by III.B.4 of Attachment 4. [40 CFR 60.13(c)]

(3) During each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour. [40 CFR 60.13(e)(2)]

(4) For the purpose of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h) [40 CFR 60.334(c)(1)]

(5) For each unit operating hour in which a valid hourly average is obtained for both NO_x and diluent, the data acquisition and handling system must calculate and record the hourly NO_x emissions in the units of the applicable NO_x emission standard under III.B.1.a. of Attachment 4 of this Attachment. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 a diluent cap value of 19.0 percent O_2 may be used in the emission calculations. [40 CFR 60.334(b)(2)(ii)]

(6) A worst case ISO correction factor may be calculated and applied using historical ambient data in accordance with the procedure in 40 CFR 60.334(b)(3)(iii). [40 CFR 60.334(b)(2)(iii)]

(B) The Permittee shall submit reports of excess emissions and monitor downtime in accordance with 40 CFR 60.7(c). The reports shall be postmarked by the 30th day following the end of each calendar quarter. Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. Periods of excess emissions and monitor downtime that shall be reported are defined as follows: [40 CFR 60.334(c)(1)(iii)]

(1) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_X concentration exceeds the applicable emission limit in Condition III.B.1.a of Attachment 4. A 4-hour rolling average NO_X concentration is the arithmetic average of the average NO_X concentration measured by the CEMS for a given hour (corrected to 15 percent O_2 and, to ISO standard conditions) and the three unit operating hour average NO_X concentrations immediately preceding that unit operating hour.

(2) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_X concentration or diluent (or both).

(3) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period. The Permittee is not required to report ambient conditions if opting to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii).

d. Annual NO_X Emission Limit

To demonstrate compliance with the annual NO_X emission limit in III.B.1.b of Attachment 4, the Permittee shall comply with the continuous emission system monitoring, recordkeeping and reporting provisions in III.E.2 of Attachment 4.

4. **Performance Testing**

The Permittee shall conduct a NO_X emissions performance test on Unit IGT3, in accordance with 40 CFR 60.8 and the test methods and procedures in 40 CFR 60.335. The performance test shall be used to demonstrate compliance with the emission limit contained in III.B.1.a of Attachment 4. [40 CFR 60.335]

C. **Sulfur Dioxide**

1. **Emission Limitations/ Standards**

a. The Permittee shall not burn in Unit IGT3, any fuel that contains total sulfur in excess of 0.8 percent by weight (8000 ppmw). [40 CFR 60.333(b)] & [PCC 17.12.190.B]
[Material Permit Condition]

b. The Permittee shall not allow the total combined emissions of SO_2 from Unit IGT3 to equal or exceed 40 tons per year, calculated as a 12-month rolling total. [PCC 17.12.190.B]

2. **Monitoring, Recordkeeping and Reporting Requirements** [PCC 17.12.190.A.3, A.4 & A.5]

a. The Permittee may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in 40 CFR 60.331(u). The Permittee shall use one of the following sources of information to make the required demonstration: [40 CFR 60.334(h)(3)]

i. The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20 grains / 100 scf or less; or

ii. Representative fuel sampling data which shows that the sulfur content of the gaseous fuel does not exceed 20 grains / 100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to 40 CFR Part 75 is required.

b. To demonstrate compliance with III.C.1.b of Attachment 7, the Permittee shall comply with the continuous emission monitoring, recordkeeping, and reporting requirements in III.E.2 of Attachment 4.

D. **Carbon Monoxide**

1. **Emission Limitations/Standards**

The Permittee shall not allow the total combined emissions of carbon monoxide (CO) from IGT3 to equal or exceed 100 tons per year, calculated as a 12-month rolling total. [PCC 17.12.190.B]
[Material Permit Condition]

2. **Monitoring, Recordkeeping and Reporting Requirements** [PCC 17.12.190.A.2, A.4 & A.5]

a. The Permittee shall install, calibrate, maintain and operate and quality-assure a Continuous Emission Monitoring System (CEMS) consisting of CO and O2 or CO2 monitors for measuring CO emissions and diluent from IGT3. [PCC 17.12.190.A.2]
[Material Permit Condition]

b. The Permittee shall install, calibrate, maintain and operate the in-line fuel flowmeter monitoring systems for determining the natural gas input rate to IGT3 for each operating hour according to the manufacturer's instructions. [PCC 17.12.190.A.2]
[Material Permit Condition]

c. To demonstrate compliance with the annual CO emission limit in III.D.1 of Attachment 7, the Permittee shall comply with the CEMS monitoring, recordkeeping, and reporting requirements in Condition III.E.2 of Attachment 4.

E. **Continuous Emissions Monitoring Systems (CEMS)** [40 CFR §60.13, PCC 17.12.190.B.3]

1. **New Source Performance Standards for Continuous Emission Monitoring Systems**

To demonstrate compliance with III.B.1.a of Attachment 7 the Permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) and data acquisition handling system (DAHS) to calculate a four hour rolling average NO_X emission rate.

a. The Permittee shall comply with the following requirements in the General Provisions of 40 CFR 60 for each CEMS unit installed:

i The CEMS and DAHS monitoring and recording devices shall be installed and operational prior to conducting initial performance test. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device. [40 CFR 60.13(b)]

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ii. The Permittee shall automatically check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span must, as a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification in 40 CFR, Part 60, appendix B. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. [40 CFR 60.13(d)(3)]

iii. Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under V.B.4.a (ii), the CEMS shall be in continuous operation and shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. [40 CFR 60.13(e)(2) and 60.13(f)]

iv. The CEMS devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of 40 CFR 60 (III.E.1.b of Attachment 4) shall be used. [40 CFR 60.13(f)]

v. The Permittee shall reduce all data to 1-hour averages. 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages. The data may be recorded in reduced or non-reduced form (e.g., ppm pollutant and percent O_2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used to specify the emission limit. [40 CFR 60.13(h)]

vi. The Permittee shall meet the notification and recordkeeping requirements in II.B.1.d and II.B.5 of Attachment 4.

b. The Permittee shall comply with the following requirements in the Performance Specifications of 40 CFR 60 Appendix B, for each CEMS unit installed:

i. The CEMS installation and measurement location specification shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.1.

ii. Pretest preparation shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.2.

iii. Calibration drift test procedure shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.3.

iv. Relative accuracy test procedure shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.4.

v. Reporting requirements shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.5.

vi. Analytical procedures shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 11.0.

vii. Calculation and data analysis shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 12.0.

viii. Method performance shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 13.0.

ix. Alternative Procedures shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 16.0.

x. References are located in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 17.0.

xi. Tables, Diagrams, Flowcharts, and Validation data necessary for NO_x CEMS testing are located in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 18.0.

xii. Specifications and test procedures for O_2 and CO_2 CEMS in Stationary Systems shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 3.

xiii. Specifications and Test Procedures for CO CEMS in Stationary Sources shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 4.

2. **Monitoring, Recordkeeping, and Reporting Requirements for Annual NO_x, SO_2, and CO Emission Limits.** [PCC 1.52, 1.66 A.3, A.4 & A.5]

a. For the purpose of compliance demonstration with annual NO_x and CO emission limits, the Permittee shall utilize the NO_x, CO, diluent CEMS on Unit IGT3 in conjunction with the Data Acquisition and Handling System (DAHS) and fuel flow rate monitoring systems. A default value for SO_2 concentration will be calculated using equation 3 below. The DAHS will calculate emissions of NO_x, SO_2 and CO in pounds per hour (lb/hr), tons per month, and tons per year, calculated monthly as a 12-month rolling total. The Permittee shall use the procedures in Method 19 of 40 CFR 60 Appendix A as applicable to calculate NO_x and CO mass emission rates.

b. The Permittee shall calculate SO_2 mass emission rates for Unit IGT3 using Equation 3 and 3A below:

ER = (2.0 / 7000) x 10^6 x (S_{fuel} / GCV) where: (Equation 3)

ER = Default SO_2 emission rate for natural gas combustion, lb/MMBtu

S_{fuel} = Total sulfur content of the natural gas from a valid purchase agreement, tariff agreement, or sampling, gr/100 scf GCV = Gross calorific value of the natural gas from a valid purchase agreement, tariff agreement, or sampling, Btu/100 scf
7,000 = Conversion of grains/100 scf to lb/100 scf.

10^6 = Conversion factor (Btu/MMBtu)

SO_2 rate = ER x HI rate; where: (Equation 3A)

SO_2 rate = Hourly mass emission rate of SO_2, lb/hr

ER = SO2 default emission rate of 0.06 lbs/MMBtu

HI rate = Hourly heat input rate, MMBtu/hr

c. A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for NO_X, CO, and diluent concentration or heat input rate.

d. During CEMS system downtime, the Permittee shall implement the missing data procedures for NO_X and CO shown in 40 CFR Part 75 Subpart D – Missing Data Substitution Procedures.

e. Each calendar month during which the combined 12-month rolling total for the NO_X emission rate from Unit IGT3 exceeds 40 tons shall constitute an exceedance. Exceedances shall be reported to the Control Officer in accordance with NI.A of Part A.

f. Each calendar month during which the combined 12-month rolling total for the SO2, emission rate from Unit IGT3, exceeds 40 tons shall constitute an exceedance. Exceedances shall be reported to the Control Officer in accordance with NI.A of Part A.

g. Each calendar month during which the combined 12-month rolling total for the CO emission rate from Unit IGT3, exceeds 100 tons shall constitute an exceedance. Exceedances shall be reported to the Control Officer in accordance with NI.A of Part A.

h. Each individual day and 12-month rolling total for NO_X, SO_2, and CO emission rates in the reporting period shall be included in the semiannual compliance certification required by VII of Part A.

i. Quality Assurance Requirements for Natural Gas Fuel Flow meters

i. Each transmitter or transducer shall be calibrated by equipment that has a current certificate of traceability to NIST standards at least once every four calendar quarters in which a unit operated on natural gas for 168 hours or more during each quarter but not less than once every three years. The Permittee shall check the calibration of each transmitter or transducer by comparing its readings to that of the NIST traceable equipment at least once at the following levels: the zero-level, and at least two other upscale levels (e.g., "mid" and "high"), such that the full range of transmitter or transducer readings corresponding to normal unit operation is represented.

ii. The Permittee shall calculate the accuracy of each transmitter or transducer at each level tested, using the following equation:

$$ACC = \frac{|R-T|}{FS} \times 100 \quad \text{Equation 4}$$

Where:

C = Accuracy of the transmitter or transducer as a percentage of full-scale.

R = Reading of the NIST traceable reference value (in milliamperes, inches of water, psi, or degrees).

T = Reading of the transmitter or transducer being tested (in milliamperes, inches of water, psi, or degrees, consistent with the units of measure of the NIST traceable reference value).

FS = Full-scale range of the transmitter or transducer being tested (in milliamperes, inches of water, psi, or degrees, consistent with the units of measure of the NIST traceable reference value).

iii. If each transmitter or transducer meets an accuracy of ± 1.0 percent of its full-scale range at each level tested, the fuel flow meter accuracy of 2.0 percent is considered to be met at all levels. If however, one or more of the transmitters or transducers does not meet an accuracy of ± 1.0 percent of full-scale at a particular level, then the Permittee may demonstrate that the fuel flow meter meets the total accuracy specification of 2.0 percent at that level by using one of the following alternative methods. If, at a particular level, the sum of the individual accuracies of the three transducers is less than or equal to 4.0 percent, the fuel flow meter accuracy specification of 2.0 percent is considered to be met for that level. Or, if at a particular level, the total fuel flow meter accuracy is 2.0 percent or less, when calculated in accordance with Part 1 of American Gas Association Report No.3, General Equations and Uncertainty Guidelines, the flow meter accuracy requirement is considered to be met for that level.

iv If during a transmitter or transducer accuracy test the flow meter accuracy specification of 2.0 percent is not met at any of the levels tested, the Permittee shall repair or replace the transmitter(s) or transducer(s) as necessary until the flow meter accuracy specification has been achieved at all levels. (Note that only transmitters or transducers which are repaired or replaced need to be re-tested; however, the re-testing is required at all three measurement levels to ensure that the flow meter accuracy specification is met at each level).

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IN RE TUCSON ELECTRIC POWER

PSD Appeal No. 18-02

ORDER DENYING REVIEW

Decided December 3, 2018

Syllabus

The Sierra Club petitions the Environmental Appeals Board ("Board") to review a decision by the Department of Environmental Quality for Pima County, Arizona ("Pima County") to issue a federal Prevention of Significant Deterioration ("PSD") permit to Tucson Electric Power. The permit authorizes Tucson Electric Power to construct and operate up to ten additional electricity-generating units ("Units") at its Irvington Generating Station facility. Sierra Club challenges Pima County's determination that PSD requirements do not apply to the nitrogen oxide ("NO_x") emissions from the modified facility. Although the permit contains a cap that limits NO_x emissions below the level triggering PSD requirements, Sierra Club argues that the permit's monitoring requirements are not adequate to render the NO_x emissions cap practically enforceable and thus PSD requirements should apply.

The permit imposes several monitoring requirements to verify compliance with the NO_x emissions cap. Those requirements include, among other things: (i) biennial performance (stack) tests to determine how much NO_x each Unit emits; (ii) calculation of monthly and yearly NO_x emissions using information from the required stack tests and monitoring of ongoing operations; and (iii) monitoring of the pollution control devices for the new Units to ensure that the devices are working properly. Pima County concluded that these compliance monitoring requirements were sufficient to make the NO_x emissions cap practically enforceable.

Held: The Board denies Sierra Club's Petition for Review. Sierra Club has not carried its burden of showing that Pima County clearly erred or abused its discretion in determining that the NO_x emissions cap is practically enforceable.

Sierra Club's argument that the NO_x emissions cap is not practically enforceable because the permit's compliance monitoring requirements rely solely on biennial stack tests lacks merit because monitoring of the facility's pollution control devices is also an integral part of the permit's compliance monitoring requirements. Sierra Club's contention that the monitoring of the pollution control devices does not cure the problem with the permit's reliance on biennial stack tests was not preserved for review because that assertion

was not raised during the public comment period. In any event, Sierra Club's contention is not responsive to the role of monitoring of the pollution control devices as described by Pima County. Additionally, Sierra Club does not substantiate its argument that Pima County failed to support in the administrative record its conclusion that the method for calculating monthly and yearly NO_x emissions would likely overstate emissions. Lastly, Pima County adequately responded to Sierra Club's comments on the practical enforceability of the NO_x emissions cap. Pima County responded to Sierra Club's generalized claims on the inadequacy of biennial stack testing to monitor compliance throughout the year by providing a description of all the elements of the permit's compliance monitoring requirements. Given the general nature of Sierra Club's comments, more was not required.

Before Environmental Appeals Judges Aaron P. Avila, Mary Kay Lynch, and Mary Beth Ward.

Opinion of the Board by Judge Ward:

I. *STATEMENT OF THE CASE*

This case involves a challenge by the Sierra Club to a determination in a federal Clean Air Act permit that the Act's Prevention of Significant Deterioration ("PSD") requirements do not apply to the emissions of nitrogen oxides – commonly referred to as NO_x – from a facility owned and operated by Tucson Electric Power ("Tucson Electric"). Potential NO_x emissions from the facility are reduced by pollution control devices, and the permit imposes a limit (or cap) on NO_x emissions consistent with the control devices' ability to reduce emissions. In such circumstances, the applicability of PSD requirements is based on the facility's emission rate, as reduced by the control devices, so long as the cap on the reduced emissions is enforceable as a practical matter. The specific issue presented here is whether the challenged permit's compliance monitoring requirements are sufficient to make the NO_x emissions cap practically enforceable.

In August 2018, the Department of Environmental Quality for Pima County, Arizona ("Pima County") issued a federal PSD permit ("Permit") to Tucson Electric authorizing the construction and operation of up to ten additional electricity-generating units ("Units") at Tucson Electric's Irvington Generating Station facility. Although the expanded facility would emit several pollutants above levels that trigger PSD requirements, the Permit imposes certain requirements as to NO_x emissions that bring those emissions below levels that trigger such requirements. Specifically, the Permit requires two existing electricity-generating units at the facility to be shut down, mandates the use of pollution control devices on the new Units that reduce NO_x emissions, and imposes a NO_x emissions cap consistent with that reduction.

The Permit further imposes monitoring and recordkeeping requirements to verify compliance with the NO_x emissions cap. Those compliance monitoring requirements include, among other things: (i) biennial performance (stack) tests to determine how much NO_x each Unit emits; (ii) calculation of monthly and yearly NO_x emissions using information from the required stack tests and monitoring of ongoing operations; and (iii) monitoring of pollution control devices to ensure that they are working properly. Finding that these compliance monitoring requirements made the NO_x emissions cap practically enforceable, Pima County concluded that PSD requirements do not apply to the new Units as to their NO_x emissions.

In its Petition for Review, Sierra Club argues that the NO_x emissions cap is not practically enforceable – that is, compliance with the cap cannot be verified – because the stack tests are conducted too infrequently, the monthly and yearly emission calculations rely solely on these infrequent stack tests, and the monitoring of pollution control devices does not cure the problem with the infrequent stack tests. As a consequence, Sierra Club contends that PSD requirements should apply to the facility's increased NO_x emissions resulting from its proposed expansion.

We conclude that Sierra Club has not carried its burden of showing that Pima County clearly erred or abused its discretion in determining that the NO_x emissions cap is practically enforceable. The Petition for Review is therefore denied.

II. *PRINCIPLES GOVERNING BOARD REVIEW*

In considering a petition filed under 40 C.F.R. § 124.19(a), the Board first evaluates whether the petitioner has met threshold procedural requirements such as timeliness, standing, issue preservation, and specificity. *In re Indeck-Elwood, LLC*, 13 E.A.D. 126, 143 (EAB 2006). For example, a petitioner must demonstrate that any issues and arguments it raises on appeal have been preserved for Board review (i.e., were raised during the public comment period or public hearing on the proposed permit), unless the issues or arguments were not reasonably ascertainable at the time. 40 C.F.R. §§ 124.13, .19(a)(4)(ii); *see, e.g.*, *In re City of Attleboro*, 14 E.A.D. 398, 405-06, 444 (EAB 2009); *In re City of Moscow*, 10 E.A.D. 135, 141, 149-50 (EAB 2001).

Under part 124, the petitioner bears the burden of demonstrating that review is warranted. *See* 40 C.F.R. § 124.19(a)(4). Ordinarily, the Board will deny review of a permit decision and thus not remand it unless the petitioner demonstrates that the permit decision is based on a clearly erroneous finding of fact or conclusion of law or involves a matter of policy or exercise of discretion that warrants review. *Id.* § 124.19(a)(4)(i)(A)-(B); *see, e.g.*, *In re La Paloma Energy Ctr., LLC*,

16 E.A.D. 267, 269 (EAB 2014). The Board's power to grant review "should be only sparingly exercised," and "most permit conditions should be finally determined at the [permit issuer's] level." Consolidated Permit Regulations, 45 Fed. Reg. 33,290, 33,412 (May 19, 1980); *see also* Revisions to Procedural Rules Applicable in Permit Appeals, 78 Fed. Reg. 5281, 5282 (Jan. 25, 2013).

When evaluating a permit decision for clear error, the Board examines the administrative record that serves as the basis for the permit to determine whether the permit issuer exercised "considered judgment" in rendering its decision. *See, e.g.*, *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 191, 224-25 (EAB 2000); *In re Ash Grove Cement Co.*, 7 E.A.D. 387, 417-18 (EAB 1997). Similarly, the Board will uphold a permitting authority's exercise of discretion if that decision is cogently explained and supported in the record. *See, e.g.*, *La Paloma Energy Ctr.*, 16 E.A.D. at 270, 284, 292. The Board does not find clear error or an abuse of discretion simply because petitioner presents a difference of opinion or alternative theory regarding a matter. *See In re Town of Ashland Wastewater Treatment Facility*, 9 E.A.D. 661, 667 (EAB 2001); *In re NE Hub Partners, L.P.*, 7 E.A.D. 561, 567-68 (EAB 1998), *review denied sub nom. Penn Fuel Gas, Inc. v. EPA*, 185 F.3d 862 (3d Cir. 1999). And on matters that are fundamentally technical or scientific in nature, the Board typically defers to a permit issuer's technical expertise and experience, as long as the permit issuer has adequately explained its rationale and supported its reasoning in the administrative record. *See, e.g.*, *In re FutureGen Indus. All., Inc.*, 16 E.A.D. 717, 733-35 (EAB 2015), *review dismissed as moot sub nom. DJL Farm LLC v. EPA*, 813 F.3d 1048 (7th Cir. 2016).

III. *STATUTORY AND REGULATORY HISTORY*

The PSD provisions of the Clean Air Act govern air pollution both in "attainment" areas, where the air quality meets or is cleaner than the Environmental Protection Agency's ("EPA") national ambient air quality standards, and in "unclassifiable" areas where EPA has not categorized the air quality as having attainment or nonattainment status. Clean Air Act ("CAA") §§ 160-169, 42 U.S.C. §§ 7470-7479; *see also In re Palmdale Energy, LLC*, PSD Appeal No. 18-01, slip op. at 4-7 (EAB Oct. 23, 2018), 17 E.A.D. ___ (providing in-depth description of the PSD program). In both these areas, the PSD program requires that new "major stationary sources" of air pollutants or "major modifications" to such sources obtain a permit prior to construction.[1] *See* CAA § 165, 42 U.S.C. § 7475; 40 C.F.R.

[1] The actual term in the PSD statutory provisions is "major emitting facility." *See* CAA § 169(1), (2)(C), 42 U.S.C. § 7479(1), (2)(C). The related term "major stationary source" is used elsewhere in the Clean Air Act, *see* CAA § 111(a), (f), 40 U.S.C. § 7411(a),

§ 52.21. Among other things, an applicant for a PSD permit must show that its facility will achieve emission limits attainable by the "best available control technology" for pollutants emitted from the facility above designated levels. CAA § 165(a)(4), 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(b)(23), (j)(2)-(3).

Under the regulations implementing the PSD program, a "major stationary source" is, among other things, any source from certain source categories (including fossil fuel-fired steam electric power plants such as the facility here) that have the "potential to emit" 100 tons per year or more of any of several regulated pollutants, including NO_x.[2] 40 C.F.R. § 52.21(b)(1)(i). A "major modification" is "any physical change in or change in the method of operation of a major stationary source" that would result in: (1) a "significant emissions increase" of any of such pollutants; and (2) a "significant net emissions increase" of any of such pollutants. *Id.* § 52.21(b)(2)(i). The regulations define a significant emissions increase and significant net emissions increase on a pollutant-by-pollutant basis. *Id.* § 52.21(b)(23), (40). For NO_x, a significant increase and a significant net increase are both defined as an increase of 40 tons per year. *Id.*

A critical aspect of determining whether a new source or the modification of a source would be a major source or major modification, respectively, is ascertaining the new source or modification's "potential to emit" pollutants and whether that potential meets or exceeds designated levels. "Potential to emit" has been defined by regulation as requiring consideration of "[a]ny physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment." *Id.* § 52.21(b)(4). However, the definition makes clear that a pollution control device's limitation on capacity can only be considered in determining a facility's potential to emit "if the limitation or the effect it would have on emissions is federally enforceable." *Id.*

(f). The Act recognizes the similarity between the two terms by defining "major stationary source" and "major emitting facility" as synonymous "[e]xcept as otherwise expressly provided." CAA § 302(j), 42 U.S.C. § 7602(j); *see Chevron, U.S.A., Inc. v. NRDC, Inc.*, 467 U.S. 837, 860 (1984). In implementing the PSD program, EPA uses the terms "major stationary source" and "major modification," 40 C.F.R. § 52.21(b)(1), (2), and, therefore, the Board will use that terminology as well. *See* U.S. EPA, *New Source Review Workshop Manual*, at A.1 (draft Oct. 1990).

[2] The applicable regulation defines these pollutants as including "[a]ny pollutant for which a national ambient air quality standard has been promulgated." 40 C.F.R. § 50.21(b)(50)(i).

Whether a physical or operational limitation on a source's emissions is "federally enforceable" has been interpreted by EPA as meaning that the emission limit reflecting the physical or operational limitation is "enforceable as a practical matter," or "practically enforceable." Memorandum from John S. Seitz, Dir., Office of Air Quality Planning & Standards, U.S. EPA, and Robert I. Van Heuvelen, Dir., Office of Regulatory Enf't, U.S. EPA, to EPA Reg'l Air Div. Dirs., Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act 3 & attach. 3, at 1 (Jan. 25, 1995) ("Seitz Memorandum"); *see also In re Peabody W. Coal Co.*, 12 E.A.D. 22, 32 (EAB 2005). To be practically enforceable, a permit must, among other things, specify "the method to determine compliance including appropriate monitoring, recordkeeping, and reporting." Seitz Memorandum at 6; *cf.* 40 C.F.R. § 49.152 (defining "enforceable as a practical matter" in a similar manner for air quality planning and management in Indian country). To be appropriate, such monitoring, recordkeeping, and reporting must be sufficient to allow a permitting agency to verify a source's compliance with the permit's emission limit. *See In re Shell Offshore, Inc.*, 15 E.A.D. 536, 557, 559 n.25 (EAB 2012) (holding that the permit issuer did not clearly err in concluding that emission limits were practically enforceable because the permit's monitoring requirements provided "the ability to assess and verify compliance"); *Peabody*, 12 E.A.D. at 39-41 (finding no clear error by the permit issuer in determining that the permittee's proposed monitoring requirements were insufficient to make an emission limit practically enforceable because the requirements did not provide "a reliable method of determining compliance"); *In re Pencor-Masada Oxynol, LLC*, Pet. No. II-2001-05, 2002 EPA CAA Title V LEXIS 44, at *16 (Adm'r Apr. 8, 2002) (stating that for an emission limit to be practically enforceable, the permit must contain terms and conditions sufficient "to determine whether the limit has been exceeded").

Pima County's Department of Environmental Quality administers the federal PSD permitting program within Pima County, Arizona pursuant to a delegation from EPA. *See* Agreement for Delegation of Source Review under the Federal Prevention of Significant Deterioration (PSD) Program Set Forth in 40 CFR 52.21 by the United States Environmental Protection Agency, Region 9 to the Pima County Air Quality Control District (June 5, 2018). Accordingly, the Tucson Electric Permit is a federally-issued permit appealable to the Board under section 124.19 of Title 40 of the Code of Federal Regulations. 40 C.F.R. § 124.19(a)(1).

IV. *FACTUAL AND PROCEDURAL HISTORY*

A. *Tucson Electric's Proposed Expansion of the Irvington Generating Station Facility*

Tucson Electric is proposing to expand its fossil fuel-fired steam electric power plant, known as the Irvington Generating Station, by building up to ten new internal combustion engine units ("Units"). Pima Cty. Dep't of Envtl. Quality, *Prevention of Significant Deterioration Air Quality Permit, Permit No. 1052*, at 4 (Aug. 8, 2018) (Administrative Record ("A.R.") 23) ("Permit"). Tucson Electric plans to use these new Units to support increased use of wind and solar-generated electrical power sources. The new Units can compensate for the variability of wind and solar power sources by providing "[r]eliable, efficient, grid-balancing resources which can ramp up quickly and provide 100 percent of their [effective load carrying capability] during multiple peak periods of any length." Tucson Elec. Power, *Application for a Prevention of Significant Deterioration (PSD) Authorization and Significant Revision to Class I Air Quality Permit for Irvington Generating Station* 2-2, 2-5 (July 2017) (A.R. 2) ("Permit Application").

The Irvington Generating Station is a major stationary source subject to the Clean Air Act's PSD program and is in an area designated by EPA as in attainment. Permit at 4. Because the proposed addition of ten new Units would significantly increase potential emissions of several regulated pollutants, this expansion of the facility qualifies as a major modification and triggers PSD requirements. *Id.* Accordingly, Tucson Electric applied to Pima County to amend its existing air quality permit (referred to as a Class I permit) and convert it to a combined PSD permit and Class I permit.[3]

The modified facility would have triggered PSD requirements for its NO_x emissions; however, Tucson Electric requested a limit on NO_x emissions – referred to by the parties as a NO_x emissions cap – for the new Units to keep their emissions below the PSD threshold.[4] *See* Letter from Conrad Spencer, Tucson Elec. Power,

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[3] The Class I permit was required to allow construction and operation of the original facility under the Arizona Administrative Code, *see* Ariz. Admin. Code § R18-2-302, which implements Arizona's operating permits program, authorized by EPA under Title V of the Clean Air Act, 42 U.S.C. §§ 7661-7661f. *See* Clean Air Act Full Approval of the Arizona Operating Permits Program, 66 Fed. Reg. 63,175 (Dec. 5, 2001) (final rule fully approving Arizona's operating permits program).

[4] In the Administrative Record, the limitation on NO_x emissions is described interchangeably as a "cap" and a "limit." *See, e.g.*, Permit at Part B § II.A.1. For clarity

to Rupesh Patel, Pima Cty. Dep't of Envtl. Prot. (Feb. 23, 2018) (A.R. 13) (requesting NO_x emissions cap of 170 tons per year). Tucson Electric also identified in its permit application three other aspects of the modified facility that would curtail NO_x emissions from the new Units or the overall facility. First, each new Unit would be equipped with a selective catalytic reduction device that would substantially reduce NO_x emissions. *See* Permit Application at 2-6, 3-3. Second, the Units would be limited to five startups per day. *See id.* at 2-6. Third, two existing steam-generating units at the facility would be permanently shut down offsetting, in part, the increase in NO_x emissions from the addition of the ten new Units. *See id.* at 2-5, 4-9. In combination, these terms of operation would limit the net increase in NO_x emissions from the expansion of the Irvington facility to an amount that is below the "significant" level of 40 tons per year.[5] Permit at 4.

We describe below: (i) the terms of the proposed combined PSD and Class I permit ("Proposed Permit") noticed for public comment with a focus on the compliance monitoring requirements pertaining to the NO_x emissions cap, *see* Part IV.B; and (ii) Sierra Club's comments on the Proposed Permit and Pima County's response to those comments, *see* Part IV.C.

B. *The Proposed Permit's Requirements Concerning the NO_x Emissions Cap*

In February 2018, Pima County issued the Proposed Permit for public comment. The Proposed Permit included the conditions necessary to restrict NO_x emissions below the level triggering PSD requirements – requiring use of selective catalytic reduction devices on each new Unit, limiting startups of the new Units to five per day, retiring two existing steam-generating units, and a 170 tons per year NO_x emissions cap – and imposed requirements to verify compliance with the NO_x

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and consistency, the Board will use the term "cap" to refer to the limitation on NO_x emissions.

[5] The to-be-eliminated steam units emit approximately 140 tons per year of NO_x. Thus, the replacement of these units with the ten new Units (limited to a combined total of 170 tons per year of NO_x) would result in a net legally-allowed increase of NO_x of approximately 30 tons per year. *See* Pima Cty. Dep't of Envtl. Quality, *Responses to Public Comments* 7 (Aug. 8, 2018) (A.R. 22) ("RTC"). Further, Pima County estimated that the ten Units would emit 152.8 tons per year of NO_x – i.e., less than the 170 tons per year cap – based on the manufacturer's specifications on NO_x emissions from the Units with selective catalytic reduction devices and assuming five startups per day, the maximum allowed under the Permit. Pima Cty. Dep't of Envtl. Quality, *Technical Support Document* attach. B at 2 tbl.B-2 (Aug. 2018) (A.R. 24).

emissions cap. Pima Cty. Dep't of Envtl. Quality, *Proposed Prevention of Significant Deterioration Air Quality Permit, Permit No. 1052*, at 4 & Part B § V.E (Feb. 9, 2018) (A.R. 12.1) ("Proposed Permit").

As to the verification of compliance, the Proposed Permit specified that "[c]ompliance with the NO_x emission [cap] shall be demonstrated by performance tests as detailed in Condition II.D, monitoring as detailed in Condition II.B, and recordkeeping as detailed in Condition II.C." *Id.* at Part B § II.A.1.b. The performance tests, monitoring, and recordkeeping required for compliance are described further below.

First, the Proposed Permit called for performance tests – also referred to as "stack tests" – for each of the new Units to be conducted "using the methods and procedures in 40 C.F.R. § 60.4244 and Table 2 of 40 C.F.R. part 60, subpart JJJJ." Proposed Permit at Part B § II.D.2.a. For NO_x emissions, these stack tests measure "the concentration of NO_x in the engine exhaust" during operation of the facility at periods other than at startup (i.e., non-startup operating periods). 40 C.F.R. § 60.4244(b), (d). Because the selective catalytic reduction devices must be operated "at all times while fuel is flowing to the [Unit], excluding periods of startup," stack tests reflect the impact the selective catalytic reduction devices have on NO_x emissions. *See* Proposed Permit at Part B § II.A.c.

In addition to the regulatory procedures for stack tests, the Proposed Permit specified that the tests "shall be performed at 25, 40, 70, and 100 percent of peak load" or at the minimum and peak load levels based on the prior twelve months of operation. *Id.* at Part B § II.D.2.b. As to the frequency of testing, each Unit must be tested "within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup." *Id.* at Part B § II.D.1. Thereafter, each Unit must be subjected to a stack test "no less frequently than once in each period of two consecutive calendar years," but at least five of the Units must be tested each calendar year. *Id.* This means that each Unit will be tested at least once every two years.

Second, the Proposed Permit imposed several monitoring and recordkeeping requirements to verify continuing compliance with the NO_x emissions cap. These monitoring and recordkeeping requirements established a procedure for calculating monthly and yearly NO_x emissions and a program for ensuring that the selective catalytic reduction devices are operated properly at all times. *See id.* at Part B § II.C.

The Proposed Permit required the calculation of NO_x emissions on a monthly and yearly basis for non-startup and startup operating periods. For non-

startup operating periods, the Proposed Permit required that monthly NO_x emissions be calculated by combining information on NO_x emission rates measured in required stack tests with monitoring data on the operation of the Units. Specifically, the Proposed Permit required that Tucson Electric calculate a NO_x "emission factor" from the most recent stack test expressed in terms of pounds of NO_x emitted per the heat input measured in British thermal units ("BTUs") of natural gas used to power the Unit. *Id.* at Part B § II.D.2.c. Additionally, the Proposed Permit required Tucson Electric to monitor and record the hours of operation of each Unit and natural gas consumption in BTUs during operation. *Id.* at Part B § II.B.1. The Proposed Permit then directed that Tucson Electric calculate monthly NO_x emissions during non-startup operating periods on a Unit-by-Unit basis by multiplying each Unit's emission factor by the BTUs of heat input used by the Unit over the month during these operating periods. *Id.* at Part B § II.C.9.

For startup operating periods, the Proposed Permit required that monthly NO_x emissions be calculated by multiplying the number of startups per Unit in a month by the manufacturer-supplied NO_x rate of emissions for startup ("startup emission rate") of the Unit. *Id.* at Part B § II.C.9. To implement this requirement, the Proposed Permit specified that Tucson Electric monitor the number of startups for all Units and record the number and duration of all startups. *Id.* at Part B § II.B.2, II.C.1. Emission calculations for startup operating periods are then combined with emission calculations for non-startup operating periods to calculate total monthly emissions and a twelve-month (i.e., yearly) rolling average of NO_x emissions. *Id.* at Part B § II.C.9.

Lastly, the Proposed Permit imposed additional requirements as to the selective catalytic reduction devices to assure proper functioning of these devices. These monitoring and recordkeeping requirements included the following: (i) the devices must be maintained and operated in a manner consistent with good air pollution control practice for minimizing NOx emissions; (ii) the catalyst in the devices must be cleaned and replaced according to the manufacturer's recommendations; (iii) two key operating parameters of the devices – ammonia injection rate and temperature – must be monitored and recorded at least once every fifteen minutes; (iv) if ammonia injection to a device fails and cannot be restored in ten minutes, the Unit must be shut down; (v) records must be kept of any instance in which ammonia injection fails for more than two minutes; and (vi) the selective catalytic reduction devices must have a continuous NO_x process monitor (which measures NO_x concentration and adjusts ammonia injection levels to achieve desired NO_x reduction). Proposed Permit at Part B § II.A.1.c, II.B.3, II.C.4; *see* Hug Eng'g, *Operating Manual: Control Unit SNQ* 1 (v03.00 Mar. 6, 2013) (A.R. 12).

C. *Sierra Club's Comments on the Proposed Permit and Pima County's Response*

Sierra Club submitted comments on the Proposed Permit arguing, among other things, that the NO_x emissions cap is not "practically enforceable,"[6] and thus the cap cannot be considered a limitation on the facility's potential to emit NO_x. Sierra Club, *Intent to Approve: Proposed Revision to the existing Air Quality Permit No. 1052 to Tucson Electric Power (TEP) Irvington/H. Wilson Sundt Generating Station (IGS)* 8-9 & attach. at 20 (Mar. 29, 2018) (A.R. 21.2) ("Sierra Club Comments"). Sierra Club contended that absent a practically enforceable limitation on the facility's potential to emit NO_x, Pima County erred in concluding that PSD requirements are not applicable to NO_x emissions. In its comments and in an expert report attached to its comments, Sierra Club advanced three arguments as to why the NO_x emissions cap is not practically enforceable.

First, Sierra Club contended that the Proposed Permit's compliance monitoring for NO_x was inadequate because it relied on stack tests that could be performed as infrequently as every two years. *Id.* at 2, 9. Sierra Club argued that "using stack tests once every two years to determine whether the [Units] are in compliance with the permit is woefully inadequate." *Id.* The expert report attached to Sierra Club's comments asserted that stack tests "may not be representative for emissions during routine operations" because stack tests do not provide data on whether pollution control devices at a facility are functioning at an effective level at times other than when the stack test is performed. *Id.* attach. at 21-22 & n.59 (citing to EPA comment letters on state permits that raise this concern as a reason to require additional compliance monitoring to supplement annual stack tests). The solution, according to the expert report, would be to require Continuous Emissions Monitors. *Id.* attach. at 23. The report argued that without Continuous Emissions Monitors, "community members will not be able to protect themselves against harmful emissions and local, state, and federal regulatory agencies cannot detect and cure violations of permit conditions." *Id.*

Second, Sierra Club argued that the NO_x emissions cap is not practically enforceable because the Permit does not contain an "unambiguous methodology for calculating NO_x emissions from the emission [stack] test." *Id.* attach. at 25; *see*

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[6] Sierra Club uses the term "practicably enforceable" as well as "practically enforceable" in its Petition. *See, e.g.*, Petition for Review of Prevention of Significant Deterioration Permit 1, 6 (Sept. 7, 2018) ("Pet."). But as we see no difference between the two (and Sierra Club does not assert that there is), the Board will use the term "practically enforceable" for clarity and consistency.

also id. at 2, 9. Sierra Club requested that the Proposed Permit "be revised to include an equation that lays out the emission calculation in detail." *Id.* attach. at 25.

Third, Sierra Club asserted that there was no record support for a manufacturer-supplied NO_x emission rate during startup, which was to be used to calculate emissions during startup operating periods. *Id.* at 2, 9 & attach. at 25. Although the Proposed Permit referred to the NO_x startup emission rate as "guaranteed," Sierra Club noted that there was no manufacturer guarantee provided for a startup NO_x emission rate included in an attachment to the draft Technical Support Document. *Id.* attach. at 25.

In August 2018, Pima County issued the Permit and its response to the public comments ("Response to Comments") received on the Proposed Permit, including its response to each of Sierra Club's comments on whether the NO_x emissions cap is practically enforceable.

As to Sierra Club's comment about the adequacy of stack tests for determining continuing compliance with the NO_x emissions cap, Pima County acknowledged that "EPA has indicated * * * that annual [stack] tests alone are insufficient to assure compliance with emission limits." Pima Cty. Dep't of Envtl. Quality, *Responses to Public Comments* 10 (Aug. 8, 2018) (A.R. 22) ("RTC"). However, Pima County explained that the Permit does not rely solely on the results of stack tests to determine compliance. *Id.* Pima County detailed how monthly and yearly NO_x emissions would be calculated using conservative non-startup emission factors and a similarly conservative startup emission rate and how monitoring of the selective catalytic reduction devices would assure that these control devices function properly at all times. *Id.* at 10-13.

In response to the request for an unambiguous methodology in calculating NO_x emissions, Pima County revised the Permit to include "a more detailed compliance determination methodology, expressed in the form of an equation." *Id.* at 13. Pima County noted that "[t]his methodology clearly indicates the emission factors and monitored data that will be used when calculating total NO_x emissions from the engines." *Id.*; *compare* Proposed Permit at Part B § II.C.9 *with* Permit at Part B § II.C.9.

Finally, to address the concern with the manufacturer-supplied startup emission rates, Pima County clarified that it had meant to reference the manufacturer-specified, not manufacturer-guaranteed, startup emission rates, and it amended the Permit accordingly. RTC at 12; *see* Permit at Part B § II.C.9. Further, Pima County admitted it had not included the latest manufacturer data in the

administrative record and explained that it had corrected this error by obtaining a waiver of the manufacturer's confidentiality claim concerning this information and included the information on its website. RTC at 4, 12.

This appeal followed.

V. *ANALYSIS*

In its Petition for Review, Sierra Club renews its challenge to Pima County's determination that the Permit's inclusion of a NO_x emissions cap prevents the addition of the ten new Units to Tucson Electric's Irvington facility from triggering PSD requirements for NO_x emissions. The sole issue that Sierra Club raises on appeal is whether the NO_x emissions cap is practically enforceable.

Specifically, Sierra Club argues (as it did in its comments) that biennial stack tests – used to develop each Unit's emission factor for calculating non-startup operating period emissions – are too infrequent to verify compliance with the NO_x emissions cap. Petition for Review of Prevention of Significant Deterioration Permit 5, 7 (Sept. 7, 2018) ("Pet."). Sierra Club further contends that reliance on biennial stack testing is not cured by the Permit's compliance monitoring requirements for the selective catalytic reduction devices or by Pima County's assertion that the emission factors for non-startup operating periods are required to be calculated in a conservative fashion. *Id.* at 12, 16 n.37. In a related vein, Sierra Club also asserts that Pima County's response to its comments was inadequate because Pima County did not "show that the permit relies on sufficient monitoring data to assure accurate and continuous monthly compliance with the NO_x cap." *Id.* at 12.

Mirroring its response to Sierra Club's comments, Pima County defends the practical enforceability of the NO_x emissions cap in its Response to the Petition by emphasizing the interconnected relationship of the entire suite of the Permit's compliance monitoring requirements. Pima County's Response to Sierra Club's Petition for Review 15, 17-19 (Oct. 1, 2018) ("Pima County Resp."); *see also* Response of Permittee Tucson Electric Power to Petition for Review 10-15 (Sept. 28, 2018) ("Tucson Electric Resp.").[7] Pima County does not claim that biennial

[7] Additionally, Tucson Electric contends that the Petition should be summarily dismissed because the question of whether a permit's compliance monitoring requirements are sufficient to ensure the practical enforceability of an emissions cap is not a "novel issue," as the Board and the Administrator have upheld substantially similar challenges to the practical enforceability of an emissions cap in *In re Shell Offshore, Inc.*, 15 E.A.D. 536,

stack testing is sufficient to make the NO_x emissions cap practically enforceable. Pima County Resp. at 16. Nor do we read Pima County's Response to Comments or its Response to the Petition as contending that biennial stack testing combined with monthly and yearly emission calculations based on that testing would *alone* provide adequate compliance monitoring requirements for the expansion of the Irvington facility. *Id.* Rather, Pima County argues that the NO_x emissions cap is practically enforceable based on how the biennial stack testing and the monthly and yearly emission calculations requirements are complemented by: (i) the requirements pertaining to the use, operation, and monitoring of the selective catalytic reduction devices; and (ii) the Permit's conservative methodology for calculating emission factors. *Id.* at 15-19; *see also* Tucson Electric Resp. at 11-15.

Given the Permit's compliance monitoring requirements and Pima County's justification for the practical enforceability of the NO_x emissions cap, the issues before us are narrower than stated by Sierra Club. Sierra Club's objections to the adequacy of the biennial stack tests and stack test-derived emission factors are not responsive to the actual compliance monitoring requirements in this Permit – which include more than stack tests and stack-test derived emission factors – and Pima County's explanation of how compliance with the Permit's NO_x emissions cap will be verified.[8] Thus, we need not determine whether biennial stack tests and use of

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546-67 (EAB 2012), and *In re Pope & Talbot, Inc., Lumber Mill*, Pet. No. VIII-2006-04, 2007 EPA CAA Title V LEXIS 3, at *12-13 (Adm'r Mar. 22, 2007). Tucson Electric Resp. at 7. We reject this argument. The Board's two main decisions involving a similar issue, *Shell Offshore* and *Peabody*, 12 E.A.D. at 34-47, as well as the Administrator's decision in *Pope & Talbot*, turned on a fact-based analysis of the permit in question, the nature of the facility, and the claims of the petitioner. They do not stand for the proposition that any permit using emission factors and monitoring of control devices to verify compliance with an emissions cap can be summarily affirmed as sufficient to ensure the practical enforceability of that cap.

[8] At times, several of Sierra Club's statements in its Petition and its comments appear to question the adequacy of the regulatorily-established requirements for conducting performance (stack) tests in subpart JJJJ, 40 C.F.R. § 60.4244, to determine the compliance of internal combustion engines with NO_x emission limitations. *See* Pet. at 11 (arguing that stack tests provide inadequate emissions compliance data due to the shortness of the tests and because they are conducted under ideal, prearranged conditions); Sierra Club Comments attach. at 21-22 & n.59 (same). To the extent Sierra Club intends this Petition to be a challenge to the requirements for tests in subpart JJJJ, 40 C.F.R. § 60.4244, that question is not properly before the Board because challenges to Clean Air Act regulations must be brought in the U.S. Court of Appeals, District of Columbia Circuit, within 60 days of promulgation. 42 U.S.C. § 7607(b). Moreover, the Board does not

emission factors based on those biennial stack tests to project monthly and yearly emissions – standing alone – would be sufficient to verify compliance with the NO_x emissions cap. What remains at issue, however, are Sierra Club's challenges to: (i) Pima County's reliance on two aspects of the Permit's compliance monitoring requirements – monitoring of the selective catalytic reduction devices and the conservative methodology for calculating emission factors for non-startup operating periods – to ensure the NO_x emissions cap is practically enforceable; and (ii) the adequacy of Pima County's response to Sierra Club's comments on the practical enforceability of the NO_x emissions cap. We address these contentions in turn below.

A. *Sierra Club's Challenges to the Permit's Compliance Monitoring Requirements*

1. *Sierra Club Fails to Show Clear Error in Pima County's Reliance on Monitoring of the Selective Catalytic Reduction Devices to Ensure the NO_x Emissions Cap is Practically Enforceable*

As discussed, the Permit's compliance monitoring requirements have two main components in addition to stack tests. The first component involves calculating monthly and yearly NO_x emissions for each Unit during non-startup and startup operating periods. NO_x emissions for non-startup periods are based on NO_x emission factors derived from stack tests conducted every two years and for startup periods are based on manufacturer data. The second component is monitoring of the selective catalytic reduction devices.

In its Petition, Sierra Club contends that the monitoring requirements for the selective catalytic reduction devices do not cure the problem with the Permit's reliance on stack tests and stack test-derived emission factors because the monitoring does not produce data to be "included in the formula to establish the NO_x emission factor." Pet. at 12. To the extent Sierra Club is challenging Pima County's conclusion that the monitoring requirements for the selective catalytic reduction devices are, in combination with the Permit's other monitoring requirements, adequate to ensure the NO_x emissions cap is practically enforceable, this argument is raised for the first time in Sierra Club's Petition. As a result, it has not been preserved for Board review. The regulations governing Board review of

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review EPA regulations as part of permit appeals. *See In re FutureGen Indus. All., Inc.*, 16 E.A.D. 717, 724 (EAB 2015) (the Board "is not the appropriate forum" for raising dissatisfaction with an EPA regulation); *In re Toudu Energy Co.*, 9 E.A.D. 710, 715-16 (EAB 2001) ("As we have repeatedly stated, permit appeals are not appropriate fora for challenging Agency regulations.").

permit appeals, require that the party seeking review establish "that each issue being raised in the petition was raised during the public comment period (including any public hearing)," or demonstrate that the issue was not "reasonably ascertainable" at that time. 40 C.F.R. § 124.13, 19(a)(4)(ii); *see, e.g.*, *In re Seneca Res. Corp.*, 16 E.A.D. 411, 415 (EAD 2014). As the Board has previously explained, "[t]he effective, efficient and predictable administration of the permitting process demands that the permit issuer be given the opportunity to address potential problems with draft permits before they become final." *In re Encogen Cogeneration Facility*, 8 E.A.D. 244, 250 (EAB 1999). This is a particularly important requirement as to technical issues such as the adequacy of the compliance monitoring requirements presented here because "the locus of responsibility for important technical decisionmaking rests primarily with the permitting authority, which has the relevant specialized expertise and experience." *Peabody*, 12 E.A.D. at 33.

Although Sierra Club did challenge the practical enforceability of the NO_x emissions cap in its comments, Sierra Club did not include as part of that challenge any critique of the role that the monitoring requirements for the selective catalytic reduction devices play. In fact, Sierra Club's comments never even mentioned the Permit's monitoring requirements for the selective catalytic reduction devices.

The section in Sierra Club's comments addressing practical enforceability of the NO_x emissions cap contains four paragraphs: (1) two paragraphs describing in general terms the legal requirement for practically enforceable emission limits; (2) one paragraph arguing that the Permit contained nothing more than a "[b]lanket" emission limitation, which was not practically enforceable; and (3) a final paragraph raising the frequency of stack tests and two other unrelated concerns with practical enforceability of the NO_x emissions cap. Sierra Club Comments at 8-9. The two other concerns were described in that final paragraph as follows:

> [Sierra Club's] expert comments detail at length the enforceability issues with the proposed permit. Specifically, using stack tests once every two years to determine whether the [Units] are in compliance with the permit is woefully inadequate. *The permit does not contain an unambiguous methodology for demonstrating compliance with the annual NO_x emission cap, and there is no support for the applicant's "vendor-guaranteed" NO_x rate that is used to demonstrate compliance.*

Id. at 9 (emphasis added) (footnote omitted). While Sierra Club's expert report, which was attached to its comments, expanded on the concerns raised with stack

tests, the methodology issue as to emission factors, and the manufacturer data on NO_x emissions during startup, that report did not raise concerns with or otherwise discuss the Permit's monitoring requirements for the selective catalytic reduction devices. *See id.* attach. at 20-25.

Sierra Club cannot claim that Pima County did not provide notice of the role that monitoring of the selective catalytic reduction devices plays in verifying compliance with the NO_x emissions cap. On its face, the Proposed Permit expressly stated that its requirements for monitoring of selective catalytic reduction devices are an element bearing on verifying compliance with the NO_x emissions cap. Condition II.A.1.b of the Proposed Permit provided that "[c]ompliance with the NO_x emission limit shall be demonstrated by performance [i.e. stack] tests as detailed in Condition II.D, monitoring as detailed in Condition II.B, and recordkeeping as detailed in Conditions II.C." Proposed Permit at Part B § II.A.1.b. And Conditions II.B and II.C on monitoring and recordkeeping, as well as Condition II.A addressing emission limitations, contain multiple requirements pertaining to monitoring of the selective catalytic reduction devices in addition to requirements as to stack tests and calculation of monthly and yearly emissions. *See id.* at Part B § II.A.1 (setting the 170 tons per year NO_x emission limit, requiring installation of selective catalytic reduction devices with continuous NO_x process monitors, and imposing operating requirements on such devices); *id.* at Part B § II.B (requiring monitoring of fuel consumption and startups of the new Units and monitoring of operating parameters – ammonia injection rate and temperature – for selective catalytic reduction devices); *id.* at Part B § II.C (requiring records be kept of the monitoring of fuel consumption, of startups of the engines, and of the operating parameters of the selective catalytic reduction devices; and specifying that monthly and yearly NO_x emissions must be calculated). Thus, the Permit's reliance on monitoring of the selective catalytic reduction devices as a key part of determining compliance with the NO_x emissions cap was reasonably ascertainable at the time of the comment period. Any challenge to the way in which the monitoring of the selective catalytic reduction devices functioned in verifying compliance with the NO_x emissions cap should have been presented to the permit issuer in the first instance.

In any event, even if Sierra Club's challenge to Pima County's reliance on the monitoring of the selective catalytic reduction devices to verify compliance with the NO_x emissions cap was preserved for Board review, Sierra Club's specific challenge (the monitoring results are not "included in the formula to establish the 'NO_x emission factor'") reflects a misunderstanding of how the Permit works. *See* Pet. at 12. In response to Sierra Club's general argument about the lack of practical enforceability of the NO_x emissions cap through reliance on biennial stack tests,

Pima County explained that it was not relying solely on stack tests to verify compliance. In addition to the required stack tests, Pima County pointed to the Permit's requirements to calculate monthly and yearly NO_x emissions and the monitoring of the selective catalytic reduction devices. RTC at 10-13. As to the latter, Pima County explained that monitoring of the selective catalytic reduction devices would assure that the devices were functioning properly "at all times." *Id.* at 10. Pima County's intent was not to obtain data from this monitoring to adjust the emission factors. Instead, the data are required to make sure the selective catalytic reduction devices are working properly at all times. Thus, Sierra Club's argument in its Petition is not responsive to the role of monitoring of the selective catalytic reduction devices as described by Pima County.

2. *Sierra Club Fails to Show Clear Error in Pima County's Determination that the Non-Startup Emission Factors Are Conservative*

In a footnote to its Petition, Sierra Club also takes issue with Pima County's assertion that the methodology for calculating emission factors for non-startup operating periods is conservative. Pet. at 16 n.37. Under Board case law, a determination such as this one by Pima County "requires the sort of quintessential technical expertise the permit issuer possesses." *In re Shell Offshore, Inc.*, 15 E.A.D. 536, 558 (EAB 2012) (upholding a permit issuer's choice of emission factors in a challenge to the practical enforceability of an emissions cap limiting a facility's potential to emit). Sierra Club has not met the "particularly heavy burden" it bears on this technical question. *See Peabody*, 12 E.A.D. at 41.

Sierra Club disputes that calculating non-startup emission factors from the highest emission rate produced during required stack tests will, as Pima County claims, result in an emission factor that "over-calculat[es]" NO_x emissions. Pet. at 16, n.37. Sierra Club maintains that there is no support in the record for this conclusion and no specific calculation of the quantitative extent of the over-calculation. We find no merit in Sierra Club's argument.[9]

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[9] Sierra Club's argument here also appears for the first time in its Petition. However, neither the Proposed Permit nor draft Technical Support Document explained that the conservative nature of the methodology for calculating non-startup emission factors was a consideration bearing on the practical enforceability of the NO_x emissions cap. That explanation appears for the first time in the Response to Comments, RTC at 13, and thus Sierra Club's challenge to that rationale may be raised on appeal. *See In re Pio Pico Energy Ctr.*, 16 E.A.D.56, 102 (EAB 2013) (allowing consideration of an issue not

First, although Pima County does state at one point that the Permit's methodology for calculating emission factors based on stack tests will overstate actual emissions, the record as a whole suggests that Pima County did not design the procedure for establishing emission factors to overstate emissions by a specific quantitative amount but rather to guard against understating emissions. For example, Pima County introduced its emission factor methodology by explaining that "certain elements [of the methodology] * * * will inherently produce a conservative calculation of emissions (i.e., a tendency to over-calculate, rather than under-calculate, engine NO_x emissions)." RTC at 13. Nor does the record show that Pima County relied upon a specific quantitative degree of over-calculation in the emission factors to justify the practical enforceability of the NO_x emissions cap.

Second, the Permit's description of the methodology for establishing an emission factor for non-startup operating periods provides sufficient record support for Pima County's description of emission factors as conservative (i.e., likely to overstate emissions). The emission factor methodology requires Tucson Electric to identify the maximum NO_x emissions that will be emitted across the full range of load levels during non-startup operating periods. To do this, the Permit requires Tucson Electric to conduct each stack test across the full range of non-startup operating load levels. Permit at Part B § II.D.2.b. The methodology then requires that the emission factor be calculated using the maximum emission rate found in that test as the presumed emission rate whenever the engine is operating in non-startup conditions, irrespective of the load level at which it is operating. *Id.* at Part B § II.D.2.c. Given that the methodology requires that the highest measured emission rate from stack tests be used in the calculation of emission factors, it was reasonable for Pima County to conclude that this approach is a conservative one. Sierra Club's "bare assertion" to the contrary is not adequate to support the opposite conclusion. *See Shell Offshore*, 15 E.A.D. at 561 n.28 (the Board refuses to rely on a petitioner's "bare assertion" that stack tests supporting emission factors were too infrequent).[10]

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raised in a public comment "where the permit issuer's reasoning on an issue was not clearly ascertainable from the record at the draft permit stage").

[10] Additionally, Sierra Club ignores that the methodology for calculating emissions during startup operating periods is also designed to conservatively calculate emissions. NO_x emissions differ significantly between "cold" or "warm" startups with cold startups generating approximately three times the NO_x emissions as warm startups. Letter from Conrad Spencer, Tucson Elec. Power, to Rupesh Patel, Pima Cty. Dep't of Envtl. Prot. 6 (Sept. 21, 2017) (A.R. 6) (finding that a cold startup emits 10.3 pounds of NO_x compared

For all the above reasons, Sierra Club fails to substantiate its claim that the record does not support Pima County's determination that the emission factor methodology is likely to overstate, not understate, actual emissions.

3. *Conclusion*

Sierra Club failed to preserve for Board review its ability to challenge Pima County's reliance on monitoring of the selective catalytic reduction devices as a component of the Permit's compliance monitoring program. Sierra Club further did not substantiate its challenge to either the adequacy of that monitoring or the conservative emission factor methodology. Accordingly, the Board concludes that Sierra Club has not carried its burden to show that Pima County clearly erred in its determination that the Permit's NO_x emissions cap is practically enforceable.

B. *Sierra Club Fails to Show Pima County Clearly Erred in Responding to Sierra Club's Comments*

Sierra Club asserts that Pima County's "responses to Sierra Club's comments were inadequate." Pet. at 12. In support of that contention, Sierra Club argues that Pima County did not "otherwise show that the permit relies on sufficient monitoring data to assure accurate and continuous monthly compliance with the NO_x cap," and "did nothing to address the fact that the NO_x cap remains practically unenforceable." *Id.*

The adequacy of a permit issuer's response to comments must be evaluated in the context of the content, specificity, and precision of the submitted comments. The Board has held that "parties submitting comments on draft permits must present their concerns with sufficient precision and specificity to apprise the permitting authorities of the significant issues so that the permit issuer can make timely and appropriate adjustments to its permit determination, or, if no adjustments are made, can explain why none are necessary in its response to comments." *In re Pio Pico Energy Ctr.*, 16 E.A.D. 56, 85 (EAB 2013). Where a comment lacks specificity and precision, the permit issuer's obligation to respond is similarly tempered. It is well settled that "permit issuers need not guess the meaning behind imprecise comments and are under no obligation to speculate about possible concerns that were not articulated in the comments." *In re Scituate Wastewater*

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to a warm startup that emits 3.5 pounds). Nonetheless, the methodology for calculating emissions during startup requires Tucson Electric to assume that all startups are cold startups. Permit at Part B II.C.9.

Treatment Plant, 12 E.A.D. 708, 723 (EAB 2006) (quotations and citations omitted).

Sierra Club's comments on practical enforceability of the NO_x emissions cap focused on the adequacy of biennial stack testing as a form of compliance monitoring and were very general in nature.[11] In its comments, Sierra Club merely stated that "using stack tests once every two years to determine whether the [Units] are in compliance with the permit is woefully inadequate." Sierra Club Comments at 9. The expert report attached to Sierra Club's comments added some detail but not much more. *See id.* attach. at 20-25. The report explained that infrequent stack tests may not be representative of "routine operations" and noted that "EPA itself has stated that annual stack tests are not sufficient to assure compliance with emissions limits." *Id.* attach. at 21-22. The information cited to support this assertion showed that EPA was concerned that annual stack tests may not be adequate to demonstrate compliance throughout the remainder of the year, particularly where the proper functioning of pollution control technology is necessary for the source to meet applicable requirements. *Id.* attach. at 21 n.59. Instead of stack testing, Sierra Club's expert report recommended that the Permit require Continuous Emissions Monitors. *Id.* attach. at 23.

Pima County responded to these comments by first acknowledging that annual stack tests "are insufficient to assure compliance with emission limits." RTC at 10. Pima County then provided a detailed explanation of what other requirements it had included in the Permit to assure sufficient compliance monitoring during all periods of operation. That lengthy explanation touched on the requirements for use of stack test-derived emission factors and manufacturer emission rates to calculate monthly and yearly NO_x emissions, the conservative nature of these emission factors and emission rates, and the required monitoring of the selective catalytic reduction devices. *Id.* at 10-13. This level of detail was more than an adequate response to Sierra Club's comment that the Permit's compliance

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[11] As described in Part IV.B, Sierra Club also argued in its comments that the NO_x emissions cap was not practically enforceable because the Proposed Permit lacked a clear statement of the methodology for calculating NO_x emissions from emission factors and because Pima County had not included in the record the manufacturer data on startup emission rates that are required for calculating emissions during startup operating periods. Sierra Club Comments at 2, 9. In response, Pima County amended the Permit to include an equation for calculating NO_x emissions and included in the record the manufacturer data on startup emission rates. RTC at 4, 13. Sierra Club has not suggested these comment responses were inadequate.

monitoring was "woefully inadequate" and the expert report explanation that infrequent stack tests may not be representative of routine operations. As the Board has previously held, if "an issue is raised only generically during the public comment period, the permit issuer is not required to provide more than a generic justification for its decision, and the petitioners cannot raise more specific concerns for the first time on appeal." *Encogen*, 8 E.A.D. at 251 n.12; *see In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 146-47 (EAB 1999) (where commenter submitted comments challenging representativeness of air quality data without supplying reasons, permit issuer's response that the data is conservative was adequate given the generic nature of the comment).

To the extent Sierra Club now raises concerns about any of the specifics of that response, we have addressed those claims in Part V.A, above. Sierra Club provides no further detail to support its claim of an inadequate response to comments. In fact, a substantial portion of Sierra Club's Petition is composed of block quotes from Pima County's explanation in the Response to Comments of its basis for concluding that the NO_x emissions cap is practically enforceable. *See* Pet. at 13-16. But as the Board's regulations make clear, when a permit issuer has addressed a petitioner's comments in the record, the petitioner must do more than insist that the permit issuer's response is incorrect, the petitioner "must * * * explain why the Regional Administrator's response to the comment was clearly erroneous or otherwise warrants review." 40 C.F.R. § 124.19(a)(4)(ii); *see In re Windfall Oil & Gas, Inc.*, 16 E.A.D. 769, 797-98 (EAB 2015) ("Simply disagreeing with the Region and repeating concerns [raised in public comments] in a petition for review * * * does not satisfy the regulatory requirement that petitioners confront the permit issuer's responses and explain why the responses were clearly erroneous."). Accordingly, the Board concludes that Sierra Club has not shown Pima County clearly erred in the manner in which it responded to Sierra Club's comments.

VI. *CONCLUSION*

For the reasons stated above, the Board denies Sierra Club's Petition for Review.

So ordered.

Exhibit 4

TECHNICAL SUPPORT DOCUMENT (TSD)

August 2018

I. General Comments:

A. Company Information

1. Tucson Electric Power (TEP) – Irvington Generating Station

2. Source Address: 3950 East Irvington Road, Tucson, AZ 85714.
   Mailing Address: 88 East Broadway Blvd, Mail Stop HQW705, Tucson Arizona or P.O. Box 711, Mail Stop HQW705, Tucson, AZ 85702.

B. Background

PDEQ received an application for a Prevention of Significant Deterioration (PSD) Authorization and Significant Revision to the Class I air quality permit (#1052) for the TEP – Irvington Generating Station (TEP-IGS or IGS) also known as the "H. Wilson Sundt Generating Station" on August 3, 2017 (revised December 2017). This TSD has been updated for this modification (See Attachment I for Previous TSD documents).

TEP's objective for the proposed facility modification is to support a more responsive and sustainable resource portfolio for power production. TEP is expanding solar and wind resources with the goal of supplying at least 30 percent of retail energy load from renewable resources by 2030. Operational challenges associated with renewable resources require TEP to develop systems to manage the intermittency and variability of energy generated by renewable resources. TEP reports recent completion of three energy storage projects designed to partially overcome these operational challenges by providing grid balancing resources. To accomplish this in part, TEP is proposing to install up to ten natural-gas fired reciprocating internal combustion engines (RICE) at IGS. The proposed RICE units will provide capacity and will mitigate power fluctuations.

The fundamental business purpose of the proposed project is to modernize and expand the IGS to allow TEP to provide reliable, efficient, grid-balancing resources which can ramp up quickly and provide 100% of the effective load carrying capacity (ELCC) during peak periods of any length. The selection of RICE units to meet this business purpose is discussed in detail in TEP's 2017 Integrated Resource Plan (IRP). In summary, TEP selected RICE units because they provide flexible, fast-responding power and assist in mitigating power fluctuations associated with renewable resources.[1]

TEP identified installation of RICE units at IGS as the best option to expand generation and integrate renewable resources.[2] Because renewable resources produce power intermittently and TEP requires back up generation capability with fast start times (capable of being on-line at full load within 5 minutes); operation across a range of loads; and fast ramping (capable of ramping from 30% to 100% load in 40 seconds). According to TEP's 2017 IRP, a Flexible Generation Technology Assessment was conducted which found that the RICE technology is the preferred technology to provide capacity and assist in

[1] Information obtained from the TEP 2017 IRP at: http://www.tep.com/wp-content/uploads/2017/04/TEP-2017-Integrated-Resource.pdf. Reviewed 15 September 2017.

[2] The "2017 Flexible Generation Technology Assessment" prepared for TEP (March 2017), included a review of various technologies including simple cycle gas turbines, reciprocating engines, combined cycle gas turbines, solar photovoltaic, wind generation and battery storage technologies. According to TEP's 2017 IRP, RICE units were selected because of their fast response, flexibility, and efficiency.

mitigating renewable energy intermittency and variability.[3] A September 2013 report by the National Renewable Energy Laboratory (NREL), noted that challenges associated with renewable energy (i.e., solar and wind power) integration include uncertainty and variability in power supply as well as difficulty balancing electric grid loads. The presence of wind and solar power sources on electric grids can cause coal or natural gas fired plants to cycle on and off more frequently to accommodate fluctuations in renewable energy power generation. Cycling on and off increases wear on the coal and natural gas fired units and decreases energy efficiency. These challenges can be overcome using a number of integration techniques, including advanced forecasting, energy storage, demand response, and flexible power generation sources such as natural gas combustion turbines and RICE units.[4]

For the reasons described above, TEP has not proposed to install energy storage or other power production technologies such as combustion turbines at IGS. Implementation of either of these options would fundamentally redefine the project. Section 2.1 of TEP's "Application for a Prevention of Significant Deterioration (PSD) Authorization and Significant Revision to Class I Air Quality Permit for Irvington Generating Station provides additional details regarding the proposed project.

Pursuant to PSD requirements, an air dispersion modeling impact analysis, an additional impact analysis, and a Best Available Control Technology (BACT) determination were conducted as part of the permit application process for the RICE project. BACT-based emission limitations were determined for the RICE and for fugitive emissions of volatile organic compounds (VOC) and greenhouse gasses (GHG) expressed as carbon dioxide-equivalents (CO_2e). The PSD permit conditions in this permit are derived by reference to 40 Code of Federal Regulations (CFR) §52.21 as the underlying authority (i.e., applicable requirement). All other conditions are not PSD permit conditions.

History

TEP-IGS is an electric utility power generating station that generates electricity by fossil fuel combustion (natural gas, liquid fuel) and landfill gas combustion. The original construction of TEP-IGS did not provide any capacity to fire coal as an alternate fuel and was regulated by the Pima County Health Services Department. In 1980 the Department of Energy (DOE) promulgated regulations that required certain large power plants to convert their operations to have the additional capacity to fire coal. Since Arizona Revised Statutes (ARS) provide that the State has original jurisdiction for coal fired electrical generating stations, the Arizona Department of Environmental Quality (ADEQ) assumed oversight from Pima County and implemented the permitting and air quality regulation of TEP-IGS. TEP applied for and received an installation permit for the coal conversion project (See Attachment I for the Arizona Department of Health Services Installation Permit (# 1156)).

Although the initial plan was to convert each electric utility steam generating unit (EUSGU or EGU) at the station, only Unit #4 was converted. Since the change was mandated by a government order, New Source Review (NSR) requirements were not applicable [Ref. definition for "major modification" in Pima County Code (PCC) and Arizona Administrative Code (AAC) – cite]. The NSPS definition for "modification" also exempts mandatory coal conversion projects [Ref. 40 CFR 60.14(e)(4) and CAA Sec 111(a)(8)]. For this reason, 40 CFR Part 60, Subpart D requirements did not apply to Unit #4 or the coal preparation plant.

In the late 1990's TEP requested that jurisdiction over TEP-IGS be returned to the Pima County Department of Environmental Quality (PDEQ); the transfer was completed shortly after the Arizona Department of Environmental Quality (ADEQ) issued a 5-year Class I permit to TEP IGS (issue date July 26, 1999). PDEQ's authority to have jurisdiction over the generating station and any standards adopted

[3] Information obtained from the footnote on page 22 of the TEP 2017 IRP located at: http://www.tep.com/wp-content/uploads/2017/04/TEP-2017-Integrated-Resource.pdf. Accessed on 15 September 2017.

[4] *Integrating Variable Renewable Energy: Challenges and Solutions*, National Renewable Energy Laboratory, NREL/TP-6A20-60451, September, 2013 (Available at: https://www.nrel.gov/docs/fy13osti/60451.pdf).

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by ADEQ affecting coal fired EUSGUs is through a delegation agreement signed between PDEQ and ADEQ.

PDEQ issued the most recent version of the permit on January 6, 2017.

Changes Since Issuance of Previous Permit

The previous permit was issued on January 6, 2017. This significant revision to the Class I, Title V air quality permit is an authorization to construct a major modification. This modification allows the installation of up to ten (10) RICE and the associated ancillary equipment. The ancillary equipment includes natural gas piping and electrical circuit breakers.

C. Attainment Classification

TEP-IGS is located in a region that is designated as attainment for all criteria pollutants.

II. Source Description

A. Process Description

TEP-IGS currently generates electricity using two fossil fuel fired processes: (1) Steam Turbine Cycle and (2) Combustion Turbine Cycle. This PSD modification approves the construction and operation of a third fossil fuel fired process: RICE. The proposed RICE are 18-cylinder, four-stroke, lean-burn natural gas fired spark-ignited RICE each with an air-cooled generator to produce electricity. In addition, there are several support facilities, some of which contain applicable requirements that are addressed by the permit.

1. Steam Turbine Cycle (Existing)

   There are three distinct units in this process: (1) Boiler; (2) Turbine; and (3) Generator.

   a. Boiler

      Water is converted to steam via combustion of fuel and heat transfer. Steam is routed to turbines while the exhaust gasses and pollutants produced during combustion are released to the ambient atmosphere after passing though air pollution controls (if required). The concentrations of pollutants released into the atmosphere depend on the fuel fired. Typical pollutants are Particulate Matter (PM), Sulfur Dioxides (SO_2), Nitrogen Oxides (NO_X), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC). Specific pollutant emission rates are provided in Section IV of this document.

   b. Turbine

      Steam exiting the boilers enters a turbine unit. The high-pressure steam passes through rotating blades which cause the turbine shaft to rotate converting the thermal energy of the steam into mechanical energy. After passing through the turbine, the steam is sent through a condenser and is recirculated to the boiler. The only process material used by the turbine unit is steam, thus there are no emissions.

   c. Generator

      The turbine drives the generator which, in turn, produces electrical energy. There are no process materials and no emissions from these units.

2. Combustion Turbine Cycle (Existing)

   There are two distinct units in this process: (1) Combustion Turbine; and (2) Generator

   a. Combustion Turbine.

      Fuel and air are mixed and injected into a combustion chamber where they are ignited. The hot combustion gases pass over the turbine blades. The resulting movement of the blades causes the shaft to rotate. Exhaust gasses and pollutants produced during combustion are released to the ambient atmosphere after passing through air pollution controls (if required). Emissions resulting from combustion typically include PM, SO_2, NO_X, CO and VOC. Representative emission rates are provided in Section IV of this document.

   b. Generator.

      The turbine drives the generator which, in turn, produces electrical energy. There are no process materials and no emissions from these units.

3. RICE (Proposed to be added in this modification)

   a. Engine.

      Combustion engines used for electric power generation are internal combustion engines in which an air-fuel mixture is compressed by a piston and ignited within a cylinder. The expansion of hot gases pushes a piston within a cylinder, which converts the linear movement of the piston into the rotating movement of a crankshaft to generate power. Each movement of the piston within a cylinder is called a stroke. electric power generation, four-stroke engines are predominately used. A four-stroke engine completes an induction stroke, a compression stroke, a power stroke, and an exhaust stroke, with two revolutions of the crankshaft, in each repetition of the cycle. RICE are described by the number of strokes to complete one power cycle and the type of combustion: spark-ignited ("SI"), as in a typical gasoline-powered vehicle, or compression-ignited ("CI"), also known as diesel engines. SI RICE are further characterized by whether the engine is operated fuel-lean (i.e., with an air-to-fuel ratio significantly greater than the stoichiometric ratio required for complete combustion) or fuel-rich (i.e., with an air-to-fuel ratio equal to or slightly greater than the stoichiometric ratio).

   b. Generator.

      The engine drives the generator which, in turn, produces electrical energy. There are no process materials and no emissions from these units

4. Support Facilities

   Other equipment, operations and process that function as support facilities are turbine starter engines, emergency generators, and cooling towers. Pollutants include PM, SO_2, NO_X, CO, and VOC.

   Support equipment for the RICE include circuit breakers and natural gas piping. Pollutants emitted include GHG.

B. Operating Capacity and Schedule

TEP-IGS requires the flexibility to operate 24 hours a day, 365 days a year. The net capacity of each power production unit is as follows:

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1. Fossil Fuel Fired Steam Generating Units:

   a. UNIT 1I – 81 MW
   b. UNIT 2I – 81 MW
   c. UNIT 3I – 104 MW
   d. UNIT 4I – 156 MW

2. Stationary Combustion Turbines:

   a. UNIT IGT1 – 24 MW
   b. UNIT IGT2 – 24.5 MW
   c. UNIT IGT3 – < 25 MW (Reserved for future installation See Alternate Operating Scenarios)

3. RICE:

   a. RICE01 – 19 MW
   b. RICE02 – 19 MW
   c. RICE03 – 19 MW
   d. RICE04 – 19 MW
   e. RICE05 – 19 MW
   f. RICE06 – 19 MW
   g. RICE07 – 19 MW
   h. RICE08 – 19 MW
   i. RICE09 – 19 MW
   j. RICE10 – 19 MW

C. **Applicability Categories**

The following categories are addressed by the permit:

1. Facility General Provisions
2. RICE (RICE01, RICE02, RICE03, RICE04, RICE05, RICE06, RICE07, RICE08, RICE09, and RICE10)
3. NSPS Subpart JJJJ Requirements for RICE (RICE01 through RICE10)
4. NESHAP Subpart ZZZZ Requirements for RICE (RICE01 through RICE10)
5. Electric Steam Generating Units EUG's (Units - 1I, 2I and 3I)
6. Electric Steam Generating Units (I4)
7. Unit I4 – Regional Haze Implementation Plan
8. Cooling Towers (1IE, 2ID, 3ID, and 4IE)
9. Stationary Rotating Machinery (IGT1, IGT1A, IGT2, and IGT2A)
10. Emergency Generators – Local Requirements (EGEN1 and EGEN2)
11. NESHAP Subpart ZZZZ Requirements for Emergency Generators (EGEN1, EGT1A and IGT2A)
12. NSPS Emergency Generator Requirements (EGEN2)
13. Nonpoint Fugitive Dust Sources
14. Use of Paints
15. Abrasive Blasting

D. **Air Pollution Control Equipment**

Air Pollution Control Equipment is required for the following equipment and processes:

1. RICE Units RICE01 through RICE10

   Oxidation catalyst will be required to be installed and operated to control VOC and CO emissions. Selective catalytic reduction (SCR) is required to be installed and operated to control NO_x emissions.

2. UNIT IGT3

   Upon purchasing the unit, the Permittee is required to install and operate a water injection system or its equivalent to control NO_x emissions

III. Regulatory History

T&P is currently in compliance with permit and regulatory requirements.

A. **Testing & Inspections**

Inspections have been conducted regularly since PDEQ took over jurisdiction from ADEQ. The last completed inspection was conducted in 2014.

B. **Excess Emissions**

NOV PC8611-037 was issued on November 15, 2016 for alleged violations of the opacity standard for IGS U4. On November 15, 2016, a Settlement Agreement was reached and was executed on March 16, 2017 to resolve the alleged violation.

IV. Emission Estimates

The following table summarizes IGS annual potential to emit of air pollutants by each emission unit and by facility-wide total. The emission estimate is to establish "major source" status of IGS pursuant to CAA Sec 501(2). Other use with the estimate may include comparing source potential-to-emit with emissions inventory and test data, or with emission rates allowable by relevant standards. This emission estimate is not meant to establish any baseline emission levels. These emission figures are not meant to be emission limitations of any form.

The majority of IGS air emissions come from the boiler units. Although natural gas is the primary fuel consumed by the boilers, Units U1-U3 are permitted to co-fire natural gas with fuel oils and Unit I4 is permitted to co-fire natural gas with landfill gas. To accommodate the co-firing scenario, a fuel mix of 85% natural gas and 15% diesel was used in calculating emissions for Units U1-U3. Similarly, a fuel mix of 95% natural gas and 5% landfill gas was used for Unit I4.

The emissions from the new RICE units are calculated based on 8,760 hours of operation per year for each of the ten RICE. The potential emission calculations were developed using emission factors for startup and non-startup operation. Per the vendor supplied documentation, cold startups occur after the RICE has not been operational for 2 to 3 days. The vendor supplied documentation is included in Attachment A. The potential emissions from the RICE were calculated assuming up to 5 cold startups per day. Although this is physically impossible because the unit will not be "cold" if it has been operational within the same day, this assumption provides a conservative estimate of startup emissions. Startups are assumed to be 30 minutes in duration and the remainder of the startup hour is assumed to be half of an operating hour. Daily emission calculations include 5 startups and 21.5 hours of operation per day. An example calculation using PM10 is:

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$$1.8\frac{lb}{startup} \times 5\frac{startups}{day} + 2.37\frac{lb}{hr} \times 21.5\frac{hr}{day} = 60.0\frac{lb}{day}$$

$$60.0\frac{lb}{day} \times 365\frac{day}{yr} \div 2000\frac{lb}{ton} = 10.9\frac{tons}{yr}$$

The permit application calculated the potential emissions of NOx based on the New Source Performance Standard (NSPS) emission limit of 1.0 g/hp-hr, resulting in an emission rate of 59.1 lb NOx/hr. The RICE vendor also provided emission factors for NOx during startup and non-startup operation. As noted in Table 1 below, the lb/hr NOx emission calculations were developed using the NSPS emission limit. The NSPS limit is incorporated in the permit as an enforceable condition. TEP also requested a limitation on annual NOx emissions of 170.0 tons/year. Therefore, the enforceable limitation on NOx emissions is 170.0 tons/year.

The emission factors used to develop the emission calculations are noted in the Table 1 below.

Table 1
RICE Emission Factors

Pollutant	Fuel Based lb/MMBtu	NSPS Limit g/(HP-hr)	Proposed BACT Limit lb/hr	Vendor Supplied Startup Emission Factor lb/event	Vendor Supplied Controlled Emission Factor lb/hr
PM	7.71E-05	---	---	---	---
PM_{10}	---	---	2.37	1.8	1.78
$PM_{2.5}$	---	---	2.37	1.8	1.78
CO	---	---	4.43	9.1	2.64
VOC	---	---	4.49	4.3	2.07
NO_X	---	1.00E+00	---	10.3[1]	1.5
SO_2	2.10E-03	---	---	---	---
Sulfuric Acid Mist	3.20E-04	---	---	---	---

The summarized RICE potential to emit is included in the IGS Facility Wide Potential to Emit Summary Table below (Table 2. Assumptions are presented in the Table 2 footnotes. The detailed RICE project emission calculations and calculation methodology are included in Attachment B.

The Facility is voluntarily accepting a NO_X emission cap of 170.0 tons/year to ensure that the RICE project net emissions increase for NO_X is 30.6 tpy, which is well below the 40 tpy significance threshold. The permit requires the permanent shut down of Unit B and Unit 12 (existing Units) prior to startup of the first RICE. The NO_X emission cap of 170.0 tpy applies to the ten RICE to be installed at the IGS. The 170.0 tpy limit is the combined total NO_X emissions for all ten RICE.

[1] 10.3 lb/event is the cold start emission factor for NO_X, which is more conservative than the 3.5 lb/event emission factor used during warm startup periods. The 10.3 lb/event emission factor will be used for calculating emissions during all startup periods, even those that occur when the engine is already warm.

For Title V air permitting purposes, the major source threshold is 100 tpy of any criteria air pollutant, 10 tpy of any single hazardous air pollutant (HAP), or 25 tpy of any HAPs combination. As shown in the Table 2, IGS is a major Title V source for the following air pollutants: PM_{10}, $PM_{2.5}$, SO_2, NO_X, CO, VOC, and HAPs.

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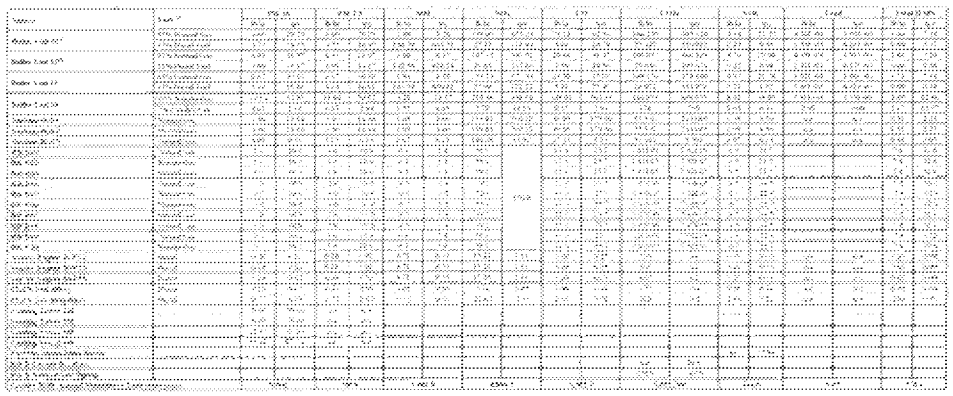

V. Applicable Requirements

A. Standards addressed by the permit:

1. Pima County State Implementation Plan (SIP):

Rule 301	Planning, Constructing, or Operating without a Permit
Rule 302	Non-Compliance with Applicable Standards
Rule 315	Roads and Streets
Rule 316	Particulate Materials
Rule 318	Vacant Lots and Open Spaces
Rule 321	Standards and Applicability
Rule 343	Visibility Limiting Standard
Rule 344	Odor Limiting Standards

2. Code of Federal Regulations Title 40:

Part 52	Approval and Promulgation of Implementation Plans
Part 60 Subpart A	General Provisions
Part 60 Subpart KKKK	Standards of Performance for Stationary Combustion Turbines (IGT3)
Part 60 Subpart JJJJ	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
Part 60 Subpart GG	Standards of Performance for Stationary Gas Turbines (IGT3)
Part 60 Appendix B	Performance Specifications
Part 63 Subpart A	General Provisions
Part 63 Subpart ZZZZ	NESHAPS for Stationary Reciprocating Internal Combustion Engines
Part 63 Subpart Q	NESHAPS for Industrial Process Cooling Towers
Part 64	Compliance Assurance Monitoring
Part 72 Subpart A	Acid Rain Program General Provisions
Part 75	Continuous Emission Monitoring
Part 75 Appendix A	Specifications and Test Procedures
Part 75 Appendix B	Quality Assurance and Quality Control
Part 75 Appendix D	Optional SO_2 Emissions Data Protocol for Gas and Oil Fired Units
Part 75 Appendix F	Conversion Procedures
Part 75 Appendix G	Determination of CO_2 Emissions

3. Pima County Code (PCC) Title 17, Chapter 17:

17.04.340	Words, phrases, and terms
17.11.020	Planning, Constructing, or Operating Without a Permit
17.11.090	Applicability – Classes of Permits
17.11.190	Permits Containing Synthetic Emission Limitations and Standards
17.11.200	Existing Source Emission Monitoring
17.12.040	Permit Contents for Class I Permits
17.12.050	Establishment of an Emissions Cap for Class I Permits
17.12.070	Acid Rain Provisions
17.16.020	Noncompliance with Applicable Standards
17.16.030	Odor Limiting Standards
17.16.040	Standards and Applicability (includes NESHAP)
17.16.050	Visibility Limiting Standards
17.16.060	Fugitive Dust Producing Activities
17.16.080	Vacant Lots and Open Spaces
17.16.090	Roads and Streets
17.16.100	Particulate Materials
17.16.110	Storage Piles
17.16.130	Applicability

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17.16.160	Standards of Performance for Fossil-Fuel Fired Steam Generators and General Fuel Burning Equipment
17.16.165	Standards of Performance for Fossil-Fuel Fired Industrial and Commercial Equipment
17.16.340	Standards of Performance for Stationary Rotating Machinery
17.16.430	Standards of Performance for Unclassified Sources
17.16.490	Standards of Performance for New Stationary Sources
17.16.560	Permits for Sources Located in Nonattainment Areas
17.16.590	Permits for Sources Located in Attainment and Unclassifiable Areas
17.16.600	Air Quality Impact Analysis and Monitoring Requirements
17.16.630	Visibility Protection

4. Installation Permit #1156 – October 14, 1981 by Arizona Department of Health Services (Attachment F)

B. Standards which are not applicable:

1. PSD/NSR

RICE01 through RICE10 have netted out of PSD (40 CFR 52.21) for NO_X.

RICE01 through RICE10 are exempt from 40 CFR Parts 74, 75, and 76.

C. Promulgated standards which will be or may be applicable not addressed by the permit:

No promulgated standards which may be applicable have been identified that are not addressed by the permit.

D. Promulgated standards which will be or may be applicable after issuance of the permit that have been addressed by the permit:

No promulgated standards which may be applicable after issuance have been addressed by the permit

VI. Previous Permit Conditions

No previous permit conditions were removed from the permit as part of this modification.

VII. Applicability Determinations

1. Prevention of Significant Deterioration (PSD)

The regulated air pollutants which will be emitted by the RICE units include CO, NO_X, VOC, SO2, PM, PM less than or equal to 10 micrometers (μm) in diameter (PM10), PM less than or equal to 2.5 μm in diameter (PM2.5), GHG, and HAPs. The project is located in an area designated as "attainment" or "unclassifiable" with respect to the National Ambient Air Quality Standards (NAAQS) for nitrogen dioxide (NO2), CO, SO2, PM, PM10, PM2.5, and lead. The project may be subject to PSD review for NOx, CO, VOC, PM10, PM2.5, and GHG. The objective of the PSD program is to prevent significant adverse environmental impact from emissions into the atmosphere from a proposed new major source or major modification at an existing major source in an attainment area by limiting allowable degradation of air quality to below levels that would be considered "significant."

There are two criteria for determining PSD applicability. The first is whether the proposed project is sufficiently large, in terms of potential emissions, to be a "major stationary source" or a "major modification" at an existing major source. TEP is an existing "Major Stationary Source" per 40 CFR

52.21(b)(1) of the federal PSD regulations because the facility is one of the 28 designated stationary source categories with potential emissions of 100 tpy or more of any regulated NSR pollutant.

The second criteria for PSD applicability under 40 CFR 52.21 requires that if a source or modification qualifies as major, its existing location must be formally designated as "attainment" or "unclassifiable" for any pollutant for which a national ambient air quality standard exists under the PSD program. TEP is located in an area classified as either "attainment" or "unclassifiable" with respect to the NAAQS for SO2, NO2, CO, PM10, PM2.5 and lead. Therefore, the Project meets both criteria and may be subject to PSD review for these pollutants. In addition, EPA's Tailoring Rule requires that if GHG emissions (expressed as CO2e) are greater than or equal to 75,000 tons per year for a project that triggers PSD review for another pollutant, then GHG emissions are also considered a PSD pollutant. Since potential GHG emissions from the Project will exceed 75,000 tpy, GHG emissions may also be subject to PSD review and need to be included in any PSD determination of BACT.

A major modification is defined as a physical change or change in the method of operation at an existing major source that would result in both a significant emissions increase and a significant net emissions increase of a regulated NSR pollutant. The RICE project will result in the emissions increases as shown in the Table 3 below. The significant emissions increase analysis looks only at the emissions increases from the RICE project. The project will result in a significant emission increase of NOx, VOC, CO, PM10, PM2.5, and GHG.

Because the project results in a significant emission increase, a significant net emissions increase analysis was conducted. The significant net emissions increase evaluates increases and decreases from "contemporaneous" projects at the source. EPA explains in Federal Register Volume 67, Number 251, Tuesday December 31, 2002 that "if your calculations show that a significant emissions increase will result from a modification, you have the option of taking into consideration any contemporaneous emissions changes that may enable you to "net out" of [PSD] review, that is, show that the net emissions increase at the major stationary source will not be significant."

A significant net emissions increase analysis was conducted for NOx. The RICE project will involve constructing new emissions units (RICE01 through RICE10) and shutting down existing emission units I1 and I2. The permit requires Units I1 and I2 to be permanently shut down prior to startup of the first RICE unit. The net emissions increase, considering the Unit I1 and I2 shutdown and the proposed NOx limit of 170.0 TPY for all 10 RICE, results in a net NOx emission increase of less than the significant emission rate. Therefore, PSD is not applicable to NO_X.

Table 3
Project Net Emissions Increase Evaluation

Pollutant	Project Emissions (TPY)	Emission Decreases from I1 and I2 Shutdown (TPY)	Net Emissions Increase (TPY)	PSD Significant Emission Rate (SER) (TPY)	PSD Review Required?
NO_X	170.0	139.4	30.6	40	N
PM10	109.4	-	109.4	15	Y
PM2.5	109.4	-	109.4	10	Y
PM	0.5	-	0.5	25	N
SO2	14.2	-	14.2	40	N
CO	256.9	-	256.9	100	Y
VOC	215.4	-	215.4	40	Y
GHG	792,630	-	792,630	75,000	Y

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TEP did not claim any creditable decreases for PM10, PM2.5, CO, VOC, and GHG. Therefore, the significant emission increase is equal to the significant net emission increase and the modification triggered PSD for PM10, PM2.5, CO, VOC, and GHG for the RICE. Because the project is a major modification for CO, VOC, PM10, PM2.5, and GHG, these five pollutants trigger a BACT determination. The project requires a PSD air impact analysis for VOC, CO, PM10, and PM2.5. The air impact analysis is required to evaluate the project impacts with regard to the National Ambient Air Quality Standards (NAAQS), PSD Class II increments, and PSD Class I increments at the eastern and western units of Saguaro National Park (SNP) and Galiuro Wilderness Area (GWA).

A PSD air quality dispersion modeling analysis was prepared for the three criteria pollutants that trigger PSD review (CO, PM10, PM2.5). Because the resulting NO_X emissions are below the NO_X significant emission rate of 40 tons per year, the NO_X emissions do not trigger New Source Review under PSD regulations and air dispersion modeling was not performed for NO_X. The dispersion modeling analysis was performed using AERMOD and included:

- An analysis of existing background monitoring concentrations relative to the NAAQS to confirm that significant impact levels (SILs) can be used in the analysis;
- Dispersion modeling to determine whether ambient impacts caused by the Project emissions exceed the SILs;
- An assessment of the proposed Project's impacts to soils, vegetation, and visibility;
- An assessment of regional population growth and associated emissions that may be caused by the proposed Project; and
- An assessment of the proposed Project's potential to affect increments, visibility, or other air quality related values (AQRVs) in Class I areas.

Her modeling demonstration was conducted based on a merged stack configuration. As a result, the Project is required to construct the RICE exhaust stacks in a manner consistent with the merged stack model approach. The RICE exhaust stacks must be configured into two groups of five stacks per group. Within each group of five there are two clusters, one of three stacks and one of two stacks each separated by slightly less than one diameter (outside edge to outside edge) from the other stack(s) in the cluster for a total of four clusters (of either two or three stacks) in two groups.

The modeling analysis demonstrates that the Project does not result in air quality impacts above the SILs for CO, PM10 and PM2.5 and does not cause or contribute to an exceedance of any NAAQS or PSD increments for these pollutants. Similarly, an analysis of Project emissions of VOC in relation to emission rates in prior modeling analyses was used to demonstrate that the Project does not result in air quality impacts above the SILs for ozone and does not cause or contribute to an exceedance of the ozone NAAQS. The detailed Air Impact Analysis documentation is included Attachment C.

Because the project is a major modification for CO, VOC, PM10, PM2.5, and GHG, these five pollutants require BACT emission limits. A full top-down BACT analysis was conducted to identify BACT for each pollutant. Before initiating the BACT analysis for a given emission unit and a given pollutant, the maximum acceptable level of control allowed under an applicable New Source Performance Standard (NSPS) or National Emission Standard for Hazardous Air Pollutants (NESHAP) as identified as the BACT "baseline". Next, an evaluation was conducted using the five-step "top-down" approach recommended by the United States Environmental Protection Agency (USEPA). The five steps of a top-down BACT analysis are:

Step 1: Identify all available control technologies with practical potential for application to the emission unit and regulated pollutant under evaluation;

Step 2: Eliminate all technically infeasible control technologies;

Step 3: Rank remaining control technologies by effectiveness and tabulate a control hierarchy;

Step 4: Evaluate most effective controls and document results; and

Step 5: Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

For existing sources that trigger PSD, 40 CFR §52.21(j)(3) states that BACT applies to each proposed emissions unit at which a net emissions increase would result from the change. The proposed project will result in a net emissions increase in PM10, PM2.5, CO, VOC and GHG. The BACT review applies to the following proposed emission units and associated pollutants:

- RICE units – PM10, PM2.5, CO, VOC, GHG (carbon dioxide [CO_2], nitrous oxide [N_2O], methane [CH_4])
- Natural gas piping – GHG (CH_4)
- High voltage circuit breakers – GHG (sulfur hexafluoride [SF_6])

PM10/PM2.5 BACT for the RICE is determined to be 2.5 pounds PM10/PM2.5 per hour for non-startup operation. PM10/PM2.5 BACT for startup is: 1) minimize time spent at idle, 2) 30-minute startup duration limit, and 3) operation according to manufacturer specifications for minimizing emissions. Although 2.5 lb/hr is deemed BACT for non-startup operation, the PM10/PM2.5 emission limit in the permit (2.37 lb/hr) is based on the BACT determination and the dispersion modeling analysis. The dispersion modeling analysis includes startup emissions and requires an emission limit of 2.37 lb/hr to demonstrate compliance (see Attachment D for details). It is notable that the NEO California Power Plant (now California Power Holdings, LLC) contains a PM10 limit that was not considered in the BACT determination. The Tehama County APCD established a 0.02 g/hp-hr PM10 BACT limit for the NEO California Power RICE. This limit is more stringent than the PM10/PM2.5 BACT limit established for the TEP RICE units, which is 0.04 g/hp-hr. However, based on conversations with Tehama County APCD, the RICE units have not been tested to confirm this emission limit. Therefore, the NEO California RICE units are using a calculated emission rate of 0.02 g/hp-hr, as opposed to stack testing to demonstrate compliance. Therefore, the 0.02 g/hp-hr PM10 emission limit is not considered to be demonstrated in practice, and thus, the 0.02 g/hp-hr PM10 emission rate is not included in the BACT analysis for the TEP RICE.

BACT for the RICE during non-startup operations is established to be 4.43 pounds of CO per hour and 4.49 pounds of VOC per hour. The CO and VOC BACT requirements for startup are to 1) minimize time spent at idle, 2) limit startup periods to no more than 30-minutes, and 3) operation according to manufacturer specifications for minimizing emissions. The CO and VOC emission limits in the permit reflect the BACT determination (4.43 lb/hr and 4.49 lb/hr, respectively). Table 4 details the BACT emission rates.

R012344

Table 4
Summary of BACT Limits

Emission Unit	Pollutant	Emission Limit(s)	Averaging Period	Work Practices	Compliance Demonstration Provisions
RICE Units	PM10/PM2.5 (condensable and filterable)	Non-startup: 2.5 pounds/hour	6 hours (average of 3 120-minute test runs)	Minimize engine's time spent at idle; startup duration limited to 30 minutes; natural gas fuel; operate per manufacturer specifications	Performance tests for condensable and filterable PM10/PM2.5; recordkeeping requirements
	CO	Non-startup: 4.43 pounds/hour	1-hour (average of 3 1-hour test runs)	Maintain oxidation catalyst inlet temperature between 450°F and 1350 °F. Minimize time at idle and limit startup duration to 30 minutes	Performance test, continuously monitor inlet catalyst temperature and pressure drop across catalyst
	VOC	Non-startup: 4.49 pounds/hour	1-hour (average of 3 1-hour test runs)	Same as above	Same as above
	GHG (CO_2)	1,100 lb of CO_2 per MW-hour (gross)	12-month rolling average	Good combustion practices	Performance testing. Monitor fuel flow. Monitor gross energy output for each engine
Natural Gas Piping	GHG (CH_4)	Not Applicable	Not Applicable	AVO LDAR with daily inspections and repair within 15 days	Recordkeeping requirements
Circuit Breakers	GHG (SF_6)			Vendor-guaranteed leak rate of 0.5 % or less per year; density monitor alarm; written LDAR program for circuit breakers	Recordkeeping requirements

The GHG BACT for the RICE is established to be 1,100 lb of CO_2 per megawatt (MW)-hour (gross). This limitation applies during all operating conditions (startup and non-startup) and is included directly in the permit as an emission limit.

GHG BACT for the natural gas piping is determined to be an audio, visual, olfactory (AVO) leak detection and repair (LDAR) program with daily monitoring. GHG BACT for the circuit breakers is determined to be a leak rate of 0.5 % or less per year, a density monitor alarm, and an LDAR program.

The full BACT analysis is included in Attachment D.

ATTACHMENT A

Vendor Supplied Emission Data

R012345

TEP
Tucson Electric Power

88 East Broadway Blvd
Tucson, AZ 85701-1720

RECEIVED BY
PIMA COUNTY
SEP 21 2017
DEPARTMENT OF
ENVIRONMENTAL QUALITY

Hand Delivery

September 21, 2017

Rupesh Patel, Air Permit Engineering Manager
Pima County Dept. of Environmental Quality
33 N. Stone Avenue, Suite 900
Tucson, AZ 85701

Subject: Confidential Business Information - Vendor Emissions Performance Specifications
H. Wilson Sundt Generating Station RICE Project

Dear Mr. Patel:

Tucson Electric Power Company ("TEP") submitted a letter on September 19, 2017, in response to your request for information ("RFI") dated September 8, 2017. This correspondence is in addition to TEP's September 19, 2017 letter and contains the following vendor-specified emissions performance information that should address Items 4 and 6 of your RFI:

- Flue gas emission statement Tucson Electric Power; and
- Expected startup emissions Tucson Electric Power

Because of proprietary nature of the vendor's technical data, TEP requests that the two attached vendor specifications be treated as confidential business information. If you have any questions in this regard, please feel free to contact Charles Kostelnik at (520) 918-8316 or me at (520) 745-3286.

Sincerely,

Conrad Spencer
Director, Sundt Modernization Project

cc: R. Gonzalez, PCDEQ
B. Bakken, TEP
C. Kostelnik, TEP
C. Campbell, ECP
M. Kaplan, AECOM

Attachments

WÄRTSILÄ

CONFIDENTIAL Emission statement

Title:	Flue gas emission statement Tucson Electric Power	Doc ID:	0048344173
		Revision:	-
Author:	Kirsi Ruotsalainen	Status:	Released
Released by:	Kirsi Ruotsalainen / 17.08.2017	Pages:	1 (3)
Organization:	- General (Energy Solutions)		
Project:	- Project information		

This document provides flue gas emissions, i.e. maximum average values for emissions measured over a period of minimum 60 minutes. The emissions are based on the site conditions, gas composition and measurement methods specified in this document.

Engine: Wärtsilä 18V50SG-B, 514 rpm (constant speed)

Site conditions:

Altitude	2520	ft
Ambient temperature, design	90	°F
Relative humidity	9	%

Gas composition [Note 1]

The emissions are valid for the following gas composition. It is understood that variations in the gas composition inside this specification will occur and are permitted, however sudden extreme changes in gas temperature, pressure or composition are not allowed.

Methane number			80		
Methane	CH_4	typical	91.56	vol-%	
Ethane	C_2H_6	typical	6.56	vol-%	
Propane	C_3H_8	max	0.39	vol-%	[Note 2]
i-Butane	$i\text{-}C_4H_{10}$	max	0.02	vol-%	[Note 2]
n-Butane	$n\text{-}C_4H_{10}$	max	0.03	vol-%	[Note 2]
i-Pentane	$i\text{-}C_5H_{12}$	max	0.00	vol-%	[Note 2]
nPentane	$n\text{-}C_5H_{12}$	max	0.00	vol-%	[Note 2]
n-Hexane	C_6H_{14}	max	0.00	vol-%	[Note 2]
Sum of other hydrocarbons			0.00	vol-%	
Nitrogen/Oxygen	N_2/O_2	typical	1.35	vol-%	
Carbon dioxide	CO_2	typical	0.09	vol-%	
Total sulphur	S	max.	5	ppm (mass base)	

Aromatic hydrocarbons, silicon based compounds or impurities resulting from the operating and maintenance of the gas delivery systems are not allowed.

Lubricating oil quality according to Wärtsilä specifications for gas engines.

Note 1 NOx emissions at part load may depend on the configuration of the pipeline network. Therefore may be necessary to adjust the NOx emission value for the overall environment system for natural gas with the contribution of up to 5 methane number as allowed by the Wärtsilä specification above.

R012346

Flue gas emissions after emission control system[1] at 25-100% engine loads as 60 minutes average:

			Load 25-100%
NO_x	as NO_2	lb/h	1.50
CO		lb/h	2.64
VOC	as CH_4	lb/h	2.07
PM_{10} (total)		lb/h	1.76
Formaldehyde		ppm-v 15% O_2, dry	14
NH_3		ppm-v 15% O_2, dry	5

Correction based upon the influence of gas composition on VOC emissions:

If the concentration the = sum of propane + butane + pentane + hexane (C_3H_8 + C_4H_{10} + C_5H_{12} + C_6H_{14}) in the pipeline natural gas exceed the values specified in paragraph "Gas composition" in this document the VOC emissions shall be corrected according to the table below. In the table the sum of propane + butane + pentane + hexane is denoted C_{3+VOC}.

	Factor for VOC correction
Concentration of VOC components in feed natural gas	VOC number guarantee*factor
0 vol-% ≤ C_{3+VOC} < 0.50 vol-%	1
0.50 vol-% ≤ C_{3+VOC} < 1.00 vol-%	1.3
1.00 vol-% ≤ C_{3+VOC} < 1.50 vol-%	1.6

Measurement Methods

Emission data are provided based upon the emission measurement methods listed below and are valid only for these methods. Based upon mutual written consent, evaluation of measurement levels can be made using alternative methods.

Emission data assumes that individual compounds identified above the sensitivity limit, but at concentrations below the lower limit of detection are reported as maximum one-half of the daily lower-limit of calibration. Measurements shall be performed so that minimum feasible detection limits are achieved if this is required for determining compliance with emission guarantees.

The flue gas stack emission measurements will be performed at steady operating condition of the engine. Prior to the start of the flue gas emission (stack) measurements, the engine shall have reached steady state operating conditions and the flue gas temperature measured after the emission control system shall be allowed to reach normal operating temperature.

Sufficiently long measurement sampling periods and number of samples shall be taken in order to get statistically representative results. To ensure accurate particulate matter (PM10) emission results of 3 samples are to be collected with a minimum sampling time of 1 hour per sample. Based on the judgement of the measurement consultant, the results of individual samples with abnormally high deviation shall be excluded

[1]: At minimum allowed engine load 10%

Time to reach compliance

The time required to reach compliance with the emission levels specified in this document will depend on operating conditions and on the temperature of the catalyst system at start. Compliance with emission data in this document will for a normal start sequence and under normal conditions be reached within 10 to 30 minutes from start signal. The emission data in this document are given for stable load operation at the continuous operating loads specified in this document.

Oxygen (O_2): EPA Method 3A (USA): Determination of Oxygen and Carbon Dioxide Emissions from Stationary Sources.

Nitrogen oxides (NOx): EPA Method 7E (USA): Determination of nitrogen oxides from stationary sources.

Carbon monoxide (CO): EPA Method 10 (USA): Determination of carbon monoxide emissions from stationary sources.

Volatile organic compounds (VOC defined as Non Methane Non Ethane Hydrocarbons): USA EPA Method 18: Measurement of gaseous organic compound emissions by gas chromatography. VOC is calculated as the sum of relevant components, which for a gas engine equipped with a high efficiency catalyst are considered to be: propane, n-butane, n-pentane, n-hexane. *Wärtsilä reserves the rights to use other commonly accepted measurement methods to show compliance with the emission guarantees for VOC emissions*

PM10 (total): Total PM_{10} is defined as the sum of the particulate matter measured with a combination of EPA 201 and 202 methods
USA EPA Method 201 (front half): Determination of particulate emissions from stationary sources.
USA EPA Method 202 Determination of condensable particulate matter from stationary sources.

Formaldehyde (HCHO)
USA EPA Method 323: Measurement of formaldehyde emissions from natural gas-fired stationary sources-acetyl acetone derivatization method. In case formaldehyde guarantee is exceeded or if significant interference from acetaldehyde is suspected CARB Method 430: Determination of Formaldehyde and Acetaldehyde in Emissions from stationary sources shall be used.

Ammonia (NH_3): Bay Area Air Quality Management District (BAAQMD) test Method ST-1B: Ammonia integrated sampling.

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ALTERNATIVE CONTROL TECHNIQUES DOCUMENT -- NO_x EMISSIONS FROM IRON AND STEEL MILLS

Emission Standards Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards

Research Triangle Park, North Carolina 27711
September 1994

ALTERNATIVE CONTROL TECHNIQUES DOCUMENTS

This report is issued by the Emission Standards Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, to provide information to State and local air pollution control agencies. Mention of trade names and commercial products is not intended to constitute endorsement or recommendation for use. Copies of this report are available -- assupplies last-- from the Library Services Office (MD-35), U. S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711 ([919] 541-5514) or, for a nominal fee, from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA 22161 ([800] 553-NTIS).

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CHAPTER 1

INTRODUCTION

Congress, in the Clean Air Act Amendments of 1990 (CAAA), amended Title I of the Clean Air Act (CAA) to address ozone nonattainment areas. A new Subpart 2 was added to Part D of Section 103. Section 183(c) of the new Subpart 2 provides that:

> [w]ithin 3 years after the date of the enactment of the [CAAA], the Administrator shall issue technical documents which identify alternative controls for all categories of stationary sources of ... oxides of nitrogen which emit, or have the potential to emit 25 tons per year or more of such air pollutant.

These documents are to be subsequently revised and updated as determined by the Administrator.

Iron and steel mills have been identified as a stationary source category with emission sources that emit more than 25 tons of nitrogen oxides (NO_x) per year. This alternative control techniques (ACT) document provides technical information on various NO_x controls for various iron and steel mill processes that State and local agencies may use to develop and implement regulatory programs to control NO_x emissions from iron and steel mills. Additional ACT documents have been developed for eight other stationary source categories.

The information in this ACT document was generated from previous EPA documents and literature searches and contacts with iron and steel manufacturers, engineering firms, control equipment vendors, and Federal, State, and local regulatory agencies. Chapter 2 presents a summary of the findings of this study. Chapter 3 provides a process description and industry characterization of iron and steel mills. A discussion of uncontrolled NO_x emission levels is presented in Chapter 4. Alternative control techniques and achievable controlled emission levels are discussed in Chapter 5. Chapter 6 presents control costs and cost effectiveness for each control technique. Environmental and energy impacts associated with the use of NO_x control techniques are discussed in Chapter 7.

CHAPTER 2

SUMMARY

2.1 SOURCES OF NO_x EMISSIONS

Integrated iron and steel mills produce steel by reducing iron ore to iron in a blast furnace and, subsequently, removing excess carbon and other impurities from the iron in a basic oxygen furnace. Other processes involve beneficiating iron ore (e.g., pelletizing), recycling of iron-bearing materials (e.g., sintering), coke-making, and steel finishing processes such as shaping, annealing, and galvanizing. All of these are high temperature processes, usually involving the combustion of fossil fuels, and all are potential sources of NO_x emissions.

Mini mills and specialty producers process steel through some subset of the full range of processes found in integrated iron and steel mills. Typically, they enter the process by melting scrap steel in an electric arc furnace, bypassing the iron-making process and attendant support activities such as sintering and coke making.

The processing order is illustrated in the simplified flow diagram in Figure 2-1. In coke making, coal is destructively distilled in coke ovens that are fired with, typically, a mixture of coke oven gas (COG) and natural gas (NG) and/or blst furnace gas(BFG). Coke oven underfiring is a high-temperature process and NO_x emissions from coke making are appreciable.

In the sinter plant, iron ore fines, coke fines, other iron-bearing materials, and (often) flux are well-mixed and spread uniformly on a traveling grate and ignited, typically with NG. As the grate travels, a forced draft causes the coke fines and other combustibles in the bed to burn. The mixture is thus heated to a fusion temperature, creating a sinter suitable for use in the blast furnace.

In the blast furnace, iron ore is reduced to molten iron (also called pig iron or hot metal). The blast furnace is a closed system with no atmospheric emissions. The effluent from the furnace, blast furnace gas (BFG) that is rich in carbon monoxide (CO), is cleaned of particulates and used as a fuel in the blast furnace stoves. Each blast furnace has three or four associated stoves that preheat the air blast supplied to the blast furnace. Because these stoves are heated primarily with BFG, NO_x emissions from the stoves have low concentrations.

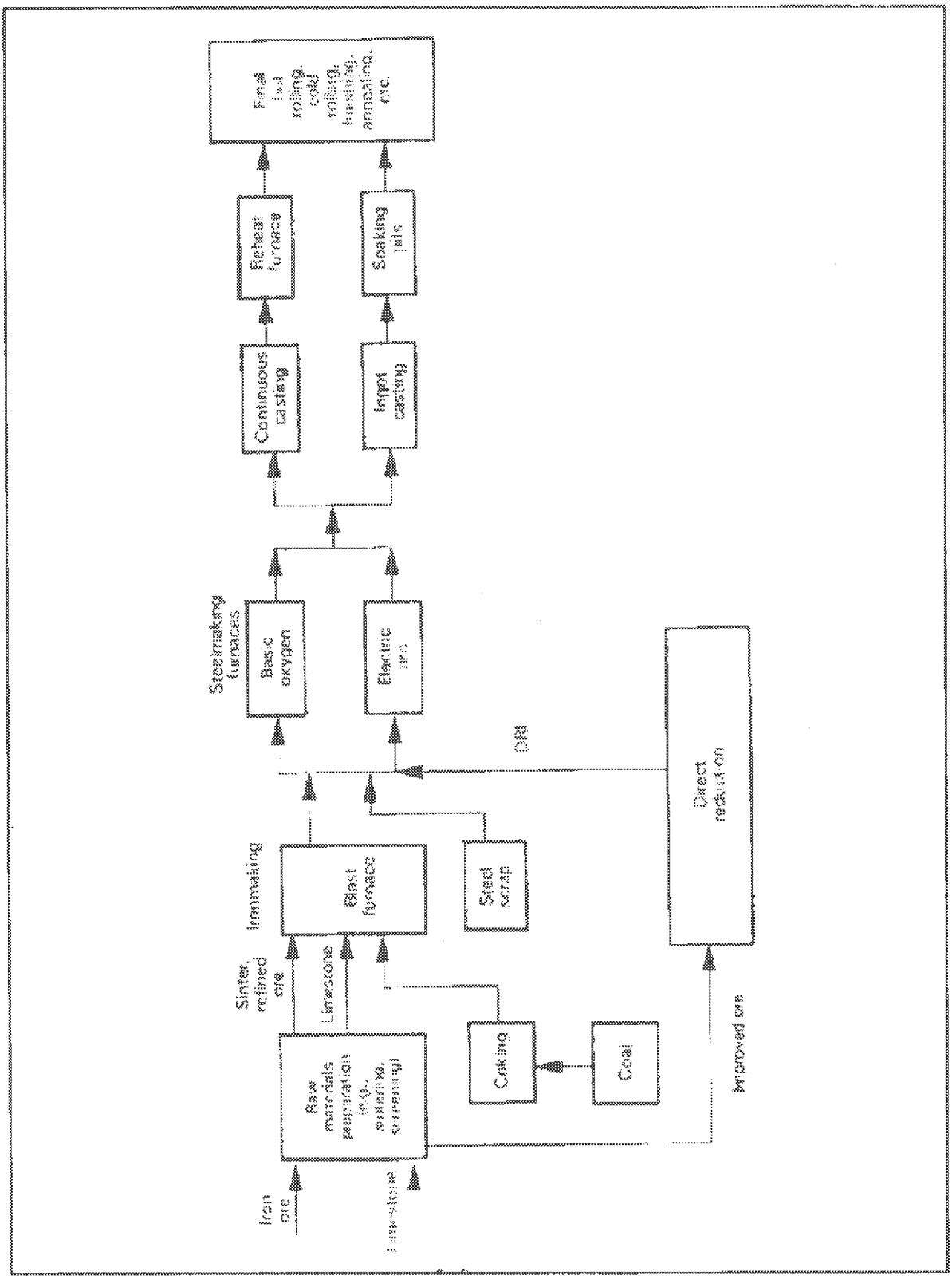

Figure 2-1. Simplified steelmaking flow chart.

Molten iron from the blast furnace, along with scrap steel, is charged to the basic oxygen furnace (BOF) where high-purity oxygen is blown on the molten bath (or upward through the bath in the case of a Q-BOP [basic oxygen process] type furnace). The oxidation of undesired elements in the bath (carbon, silicon, manganese, etc.) converts the hot metal into steel and brings the bath to a suitable pouring temperature. Combustible off-gases from the process are typically collected in an open hood above the furnace that admits air and are burned. Some furnaces are equipped with suppression-type hoods that prevent air from mixing with the off-gases above the furnace, and the off-gas is subsequently flared. During the combustion of the off-gas, thermal NO_x is generated.

Scrap steel is melted in electric arc furnaces (EAF's) where radiant heat from an electric arc established between the electrodes (usually powered from a three-phase utility-based supply) and the scrap or molten steel bath is used to bring the charge to pouring temperature. Heating due to the electric current passing through the scrap or molten bath is a minor part of the total heat input. The use of electricity for steel melting transfers the generation of NO_x from the iron and steel mill to a utility generating plant. However, oxygen and NG are sometimes used to preheat the charge. Thus EAF's are NO_x emission sources.

Molten steel from steel-making furnaces is typically processed through a continuous caster where it is shaped into slabs, billets, or blooms. Alternatively, it may be cast into ingots and stored for subsequent processing. Slabs, billets, and blooms from the continuous caster are typically reheated to suitable working temperatures in reheat furnaces prior to being passed through mills for further shaping. Ingots are typically reheated in soaking pits prior to subsequent processing. Reheat furnaces and soaking pits are high-temperature, fossil fuel (typically natural gas) burning furnaces and are sources of NO_x emissions.

Finishing processes such as annealing and galvanizing also involve reheating steel products to suitable temperatures for processing. Consequently, these finishing processes are also sources of NO_x emissions.

2.2 UNCONTROLLED NO_x EMISSIONS

There are three fundamentally different mechanisms of NO_x formation. These mechanisms yield (1) thermal NO_x, (2) fuel NO_x, and (3) prompt NO_x. The thermal NO_x mechanism arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in combustion air. The fuel NO_x mechanism arises from the evolution and reaction of fuel-bound nitrogen

compounds with oxygen. The prompt NO_x mechanism involves the intermediate formation of hydrogen cyanide (HCN), followed by the oxidation of HCN to NO. Natural gas and most distillate oils have no chemically bound fuel nitrogen and essentially all NO_x formed from the combustion of these fuels is thermal NO_x. Residual oils and coals all have fuel-bound nitrogen and, when these are combusted, NO_x is formed by all three mechanisms.

Iron and steel mill processes tend to use gaseous fuels, i.e., NG, COG, BFG, and oxygen, and the NO_x generation tends to be thermal NO_x. Exceptions include sintering where coke fines are burned as a fuel and coke ovens where coal is destructively distilled in the absence of air. Emissions from sintering and fugitive emissions from coke ovens may be sources of fuel NO_x emissions. Prompt NO_x formation is not a major factor. It forms only in fuel-rich flames, which are inherently low NO_x emitters. Thermal NO_x formation is the predominant mechanism of NO_x generation at iron and steel mills.

Very little NO_x emissions data are available in the literature relevant to iron and steel processes. Table 2-1 summaries uncontrolled NO_x emissions from the major process facilities found in iron and steel mills. This summary is based on the available emissions data obtained during the preparation of this document. The data are presented in Appendix A of this document.

The uncontrolled NO_x emissions tabulated in Table 2-1 indicate that coke-oven underfiring, sintering, reheat furnaces, annealing furnaces, and galvanizing furnaces are facilities with emission factors that range from 120 to 940 ppm at 3 percent O_2. Data available for both preheated combustion air and cold combustion air furnaces show that NO_x emission factors are much higher when the combustion air is preheated. For some facilities, e.g., reheat furnaces, there is much scatter in the data, and the averages presented in Table 2-1 may not be representative of individual furnaces.

2.3 NO_x EMISSIONS REDUCTION TECHNIQUES

Control techniques for NO_x emissions can be placed into one of two basic categories: techniques designed to minimize NO_x generation and techniques to remove previously generated NO_x from the waste effluent stream. Combustion modification techniques such as low-NO_x burners (LNB's) and flue gas recirculation fit into the first category. Add-on flue gas treatment techniques such as selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR) are examples of the second.

Few facilities found at iron and steel mills have NO_x controls. For many facilities, a suitable control technique has

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TABLE 2-1. SUMMARY OF AVERAGE UNCONTROLLED NO_x EMISSIONS

PROCESS FACILITY	FIRING TYPE	UNCONTROLLED EMISSIONS (PPM @3% O_2)	UNCONTROLLED EMISSIONS (LB/MMBtu)
Coke-oven underfiring	---	800	0.66
Sintering	---	340	0.47
Blast furnace stoves	---	30	0.021
Basic Oxygen Furnace			
during O_2 blow	---	60	---
during non blow	---	280	---
EAF	---	10	---
Soaking Pits	Preheat	---	0.14
Reheat Furnace	Regenerative	650	0.79
	Recuperative	220	0.20
	Cold-Air	120	0.14
Annealing Furnace	Regenerative	780	1.15
	Recuperative	330	0.40
	Cold-Air	120	0.15
Galvanizing Furnace	Regenerative	9240	1.2
	Recuperative	330	0.40
	Cold-Air	120	0.14

not been demonstrated. These facilities include sinter plants, coke ovens, blast furnace stoves, and steelmaking furnaces. The Japanese have investigated using SCR for sinter plants and coke ovens. These efforts appear to be experimental, and SCR is not used routinely on these facilities in Japan. Iron and steel process facilities known to have NO_x controls applied are reheat furnaces, annealing furnaces, and galvanizing furnaces. Control techniques known to have been applied to these facilities are as follows:

Reheat furnaces	Low excess air (LEA) LNB's LNB plus flue gas recirculation (FGR)
Annealing furnaces	LNB LNB plus FGR SCR LNB plus SCR
Galvanizing furnaces	LNB LNB plus FGR.

Other control techniques are discussed in this document.

Table 2-2 summarizes controlled NO_x emissions data and estimates and percent reductions. Percent reductions range from 13 to 90%. For reheat furnces controlled emissions range from 25 ppm @ 3% O_2 for cold air furnace controlled by LNB+ FGR to 560 ppm for a regenerative furnace controlled by LEA. Emissions reductions for the reheat furnaces with preheated combustion air range from 0.03 lb NO_x/MMBtu for an LEA-controlled recuperative-fired furnace to 0.61 lb NO_x/MMBtu for regenerative-fired furnace. Due to low uncontrolled NO_x emissions, the emissions reductions for cold air reheat furnace are much lower.

For annealing furnaces, controlled emissions range from 10 ppm for a cold-air fired furnace controlled by LNB+SCR to 390 ppm for a regenerative-fired furnace controlled by LNB. Annealing furnace emissions reductions range from 0.07 lb NO_x/MMBtu for a cold-fired furnace with LNB to 0.85 lb NO_x/MMBtu for a regenerative-fired furnace with LNB plus SCR controls.

For galvanizing furnaces, controlled emissions range from 50 ppm for a cold- air fired furnace controlled by LNB+FGR to 470 ppm for a regenerative-fired furnace controlled by LNB. Emissions reductions for galvanizing furnaces range from 0.07 lb/MMBtu for a cold-air fired furnace with LNB to 0.69 lb/MMBtu to a regenerative-fired furnace controlled by LNB+FGR.

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Control	Firing Type	Capital Cost ($1,000)	Annual Costs ($1,000/yr)	NO_x Reduction (tons/yr)	Cost Effectiveness ($/ton)
LNB+SCR	Regenerative	4,500	870	680	1,300
	Recuperative	4,500	870	280	3,100
	Cold-air	4,500	870	110	7,900
LNB+SNCR	Regenerative	1,200	340	600	570
	Recuperative	1,200	340	250	1,100
	Cold-air	1,200	340	100	3,400

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TABLE 2-5. COSTS AND COST EFFECTIVENESS - EXISTING GALVANIZING FURNACES (100 MMBtu/hr)

Control	Firing Type	Capital Cost ($1,000)	Annual Costs ($1,000/yr)	NO_x Reduction (tons/yr)	Cost Effectiveness ($/ton)
LNB	Regenerative	250	40	340	110
	Recuperative	250	40	120	320
	Cold-air	250	40	40	900
LNB/FGR	Regenerative	380	60	420	140
	Recuperative	380	60	140	410
	Cold-air	380	60	50	1,200

2.5.1 Air Impacts of Combustion Modification Techniques

All of the listed combustion modification NO_x control techniques, LEA, LNB, and LNB plus FGR, may increase CO and unburned hydrocarbon (HC) emissions. The NO_x reduction mechanisms inherent in these modification techniques are the reduction of peak flame temperatures, which is exponentially related to the formation of thermal NO_x and the reduced availability of excess oxygen needed to form NO_x. Reducing the availability of oxygen to the combustion process increases the likelihood that some HC will not be burned and that some CO will not be oxidized to CO_2. However, if the control is properly designed and applied, NO_x control can be achieved without increasing CO or HC emissions.

Data contained in the process heaters and glass ACT documents indicate that decreases in excess oxygen levels begin to impact CO emissions below 3 percent excess oxygen. Data in the utility boilers ACT document show that CO emissions increase for some boilers and decreace for others when implementing combustion modifications. In a steel reheat furnace with LEA for NO_x control, CO emissions of 39 ppm at 3 percent O_2 and 26 ppm at 3 percent O_2 are reported for the uncontrolled and controlled tests, respectively. These results indicate that CO emissions do not necessarily increase when LEA is implemented for NO_x control.

Other available information reports CO emissions from an LNB-controlled reheat furnace to be 20 to 30 ppm at 3 percent O_2. Further, laboratory and field tests on a galvanizing furnace yielded NO_x emissions of 550 to 1,200 ppm at 3 percent O_2 and, concurrently, negligible CO emissions. Modifications to the burners reduced NO_x emissions to 350 to 430 ppm at 3 percent O_2 and, concurrently, increased CO emissions to 30 to 60 ppm at 3 percent O_2. The purpose of the modifications was to reduce NO_x.

No explicit data are available relevant to the impact of NO_x control techniques on HC emissions from iron and steel process facilities. In general, controls that reduce NO_x by reducing the availability of excess oxygen in the high-temperature regions of a furnace would not increase either CO or HC emissions unless oxygen availability was reduced excessively. Limite d data in the Industrial-Commercial-Institutional Boilers ACT document indicate that HC emissions do not change due to the implementation of combustion modifications.

Reheat, annealing, and galvanizing furnaces predominantly use natural gas as a fuel. Natural gas does not contain sulfur and, consequently, SO_2 is not emitted. Gaseous fuels, including natural gas, can produce soot and carbon black when burned if insufficient oxygen is present. However, no evidence indicates that NO_x controls increase particulate emissions in these iron

and steel facilities.

2.5.2 Air Impacts of SCR and SNCR

SCR units are add-on, flue gas treatment facilities that reduce NO_x by injecting ammonia (NH_3) upstream of a catalyst reactor. Within the catalyst, NO_x reacts with the NH_3 and is reduced to N_2 and water (H_2O). There is a potential for unreacted NH_3 to escape with the flue gas from the SCR unit. Any such emissions are referred to as ammonia slip.

Two examples of SCR controls on annealing furnaces at iron and steel mills are reported. One of these units is operational with more than 3 years' operating history, and one is still under construction. In the case of the former, the NH_3 slip was guaranteed to be less than 10 ppm initially and less than 12 ppm after 1 year. The observed NH_3 was initially less than 10 ppm. Subsequent observations are not reported. The typical NH_3/NO_x molar ratio for this unit is 0.9.

Other reports indicate that NO_x removal rates of 70 to 90 percent can be achieved with SCR using NH_3/NO_x molar ratios between 0.9 and 1.0, and that the NH_3 slip will be between 5 and 10 ppm. These levels are considered to be well below health and odor thresholds.

SNCR has not been applied to iron and steel mill process facilities. In other SNCR applications, ammonia slip is controlled to acceptable levels by controlling the ammonia to NO_x molar ratio. These levels are similar to ammonia emissions from SCR applications, e.g., 10 ppm.

Pilot-scale testing and chemical kinetic modeling of SNCR processes have shown that nitrous oxide (N_2O) emissions are a by-product of both ammonia (NH_3) and urea injection. The N_2O formation resulting from these processes has been shown to be dependent on the reagent used, the amount of reagent injected, and the injection temperature.

Full-scale tests on fossil-fuel-fired boilers have shown that direct emissions of N_2O are less than 15 ppm and do not generally correlate with NO_x emissions. N_2O production is higher for urea injection than it is for NH_3 injection.

2.5.3 Solid Waste Impacts

The only NO_x control with solid waste impacts is SCR due to

the disposal of spent catalyst materials. Titanium dioxide and vanadium/titanium have been identified as the catalysts in the two SCR annealing furnace applications cited. Other commonly used materials are vanadium pentoxide, tungsten trioxide, platinum, zeolites, and ceramics. Of these, vanadium pentoxide is a toxic compound and a cause for concern. However, worker safety precautions adequately prevent any increased risk to workers handling the catalyst, and stack emissions of vanadium pentoxide are 1 million times less than industrial worker exposure.

Most catalyst manufacturers arrange to recycle and reactivate the catalyst. When that is not practical, the spent catalyst can be disposed of in an approved landfill in accordance with the Land Disposal Restrictions in 40 CFR Part 268, Subpart D.

2.5.4 Energy Impacts

All of the combustion modification control techniques have the potential to impact energy requirements by affecting the thermal efficiency of the process. No data are available to quantify the impact of these controls on iron and steel mill process facilities.

SCR results in a pressure drop across the catalyst that requires additional electrical energy for the flue gas fan. One estimates a cost of $537/yr assuming 8,000 hours operation per year and electricity at 8 cents/kWh.

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TABLE 2-2. NO_x CONTROLLED EMISSIONS AND PERCENT REDUCTIONS

FURNACE TYPE	CONTROL	EMISSIONS (LB/MMBtu) REGENERATIVE	EMISSIONS (LB/MMBtu) RECUPERATIVE	EMISSIONS (LB/MMBtu) COLD-AIR	PERCENT REDUCTION
REHEAT	LEA	0.69	0.17	0.12	13
	LNB	0.27	0.068	0.046	66
	LNB+FGR	0.18	0.046	0.031	77
ANNEALING	LNB	0.48	0.20	0.07	50
	LNB+FGR	0.38	0.16	0.07	60
	SNCR	0.38	0.16	0.07	60
	SCR	0.14	0.06	0.02	85
	LNB+SNCR	0.19	0.08	0.03	80
	LNB+SCR	0.095	0.04	0.015	90
GALVANIZING	LNB	0.57	0.20	0.07	50
	LNB+FGR	0.46	0.16	0.06	60

2.4 COSTS AND COST EFFECTIVENESS OF NO_x CONTROL TECHNIQUES

Tables 2-3 thru 2-5 present costs and cost- effectiveness estimates for NO_x controls for reheat, annealing and galvanizing furnaces, respectively. These estimates are based on a limited data base. Controlled NO_x missions (and, consequently, emissions reductions) are often based on test data from a single furnace. Costs are also based on limited data, often a single example furnace, that do not account for site-specific factors. All costs are in April 1994$.

Costs and cost effectiveness vary with furnace firing capacity. In discussing cost effectiveness in Tables 2-3 thru 2-5, values used refer to the mid-size capacity furnace unless stated otherwise and are for existing furnaces. For combustion modification controls such as LNB and LNB/FGR, costs and cost effectiveness for new furnaces are approximately 1/3 - 1/4 the corresponding number for new sources. For add-on controls only(SNCR and SCR), costs and cost effectiveness are the same for both new and existing sources.

As shown in Table 2-3, the cost effectiveness of existing mid-size reheat furnaces of all control techniques range from $90/ton NO_x removed (LNB on a regenerative-fired furnace) to $2,400/ton NO_x removed (LEA on a cold-air fired furnace). Only LEA has cost effectiveness greater than $700/ton. Capital costs and annual costs for the various controls range from $190,000 to 340,000 and $51,000 to 83,000 respectively.

For existing mid-size annealing furnaces (Table 2-4) cost effectiveness of all control techniques range from $200/ton NO_x removed (for LNB at a regenerative fired annealing furnace) to $7,900/ton NO_x removed (for LNB+SCR at a cold-air fired furnace). Capital costs range from $540,000 to 4,500,000 and annual costs from $77,000 to 870,000.

For existing mid-size galvanizing furnaces (Table 2-5), cost effectiveness of all control techniques range from $110/ton for LNB on a regenerative-fired furnace to $1,200/ton for LNB+FGR on a cold-air fired furnace. Capital costs for the two controls are $250,000 and $ 380,000. Annual costs are $58,000 and $70,000.

2.5 IMPACTS OF NO_x CONTROLS

All of the NO_x control techniques listed in Section 2.3 have the potential to impact other air emissions in addition to NO_x, and all may have energy impacts. SCR units may have a solid waste impact in the disposal of spent SCR catalyst. None of the listed techniques have a wastewater impact.

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TABLE 2-3. COSTS AND COST EFFECTIVENESS - EXISTING REHEAT FURNACES (300 MMBtu/hr)

Control	Firing Type	Capital Cost ($1,000)	Annual Costs ($1,000/yr)	NO_x Reduction (tons/yr)	Cost Effectiveness ($/ton)
LEA	Regenerative	190	51	120	410
	Recuperative	190	51	30	1,600
	Cold-air	190	51	20	2,400
LNB	Regenerative	230	60	620	90
	Recuperative	230	60	160	350
	Cold-air	230	60	110	400
LNB/FGR	Regenerative	340	83	730	110
	Recuperative	340	83	180	460
	Cold-air	340	83	120	690

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TABLE 2-4. COSTS AND COST EFFECTIVENESS - EXISTING ANNEALING FURNACES (200 MMBtu/hr)

Control	Firing Type	Capital Cost ($1,000)	Annual Costs ($1,000/yr)	NO_x Reduction (tons/yr)	Cost Effectiveness ($/ton)
LNB	Regenerative	540	77	380	200
	Recuperative	540	77	160	480
	Cold-air	540	77	60	1,300
LNB + FGR	Regenerative	810	120	450	260
	Recuperative	810	120	200	580
	Cold-air	810	120	70	1,600
SNCR	Regenerative	690	260	450	580
	Recuperative	690	260	200	1,300
	Cold-air	690	260	70	3,700
SCR	Regenerative	4,000	790	640	1,200
	Recuperative	4,000	790	270	2,900
	Cold-air	4,000	790	110	7,200

CHAPTER 3

INDUSTRY DESCRIPTION

Iron and steel are essential commodities in a modern, industrialized society. Steel is a widely used industrial material affecting every facet of society. Steel is a major component of every transportation system, present in every motorized vehicle and in the network of highways, bridges, and traffic controls. It is a widely used construction material, present in every home, skyscraper, and dam. Steel is essential for most industrial facilities, prevalent in defense hardware, and found in most durable goods. The uses of steel are too prevalent and too diverse to be listed completely or to serve as a basis for classification.

Section 3.1 of this chapter presents a brief background/historical discussion of the evolution of iron and steel processing. Section 3.2 is a brief industry characterization including an overview description of the major production processes and an overview of the industry. Section 3.3 presents a description of those processes with a potential for large NO_x emissions.

3.1 BACKGROUND

Iron (Fe) is one of the more abundant and widely distributed elements in the earth's crust, constituting not less than 4 percent of the total crust. It is the fourth most abundant element in the earth's crust, outranked only by aluminum, silicon, and oxygen. Pure iron is a silvery white, relatively soft metal that readily combines with other elements, e.g., oxygen and sulfur. Consequently, native metallic iron is rarely found in nature.[1,2] Iron oxides are the most prevalent natural form of iron. That portion of the iron oxides that is of commercial significance, i.e., economically and spatially available for industry use, is referred to as iron ore, and iron ore deposits are widely distributed. These deposits vary widely in mineralogy, chemical composition, and physical characteristics. The United States has abundant reserves of iron ore. These reserves are grouped into five areas: Lake Superior, Northeastern, Missouri, Southeastern, and Western. Of these, the Lake Superior reserves are the most important.[3]

Steel is the generic name for a group of ferrous metals composed principally of iron which, because of their abundance, durability, versatility, and low cost, are among the most useful metallic materials known. Most steels contain more than 98 percent iron. Steel also contains carbon, up to about 2 percent, and may contain other elements. By controlling the carbon

content and alloying elements, and by proper selection of heat treatment in the finishing processes, steel can be produced with a wide range of mechanical and physical properties.

3.1.1 A Historical Perspective

Facilities for reducing iron ore (iron oxide) to metallic iron have evolved to the modern blast furnace that produces iron from ore and other iron-bearing materials (e.g., sinter, pellets, steelmaking slag, and scrap), coke, and flux (limestone and dolomite). In the blast furnace, a blast of heated air and, in most instances, a gaseous or liquid fuel, are injected near the bottom of the furnace. The heated air burns the fuel and the coke to produce the heat required by the process and the reducing gas that removes oxygen from the ore. The reduced iron melts and pools in the bottom of the furnace where it is periodically drained through tapping holes as molten pig iron or hot metal.[4]

Modern steel making dates from the introduction of the pneumatic or Bessemer process in 1856. The Bessemer process involved forcing air through molten pig iron to oxidize the major impurities (silicon, manganese, and carbon). The Bessemer process was quickly followed by development of the open-hearth furnace that evolved into the principal means of producing steel throughout the world.[5] Open-hearth furnaces were used in the United States to produce steel into this decade, but all have now been replaced by modern basic oxygen furnaces(BOF).

In the modern basic oxygen furnace, high-purity oxygen is blown onto the surface of the hot metal (top-blown or basic oxygen process) or up through the hot metal (bottom-blown or Q-BOP process), oxidizing or removing excess carbon, silicon, manganese, and other impurities from the hot metal to produce steel of a desired composition.[6]

3.1.2 An Overview of the U.S. Iron and Steel Industry

Steel production is an international industry serving a highly competitive, international market. The United States is one of about 85 steel-producing nations and accounts for about 12 percent of the 1991 world production. In 1990, the United States produced about 99 million tons of raw steel. Of this total, 37 percent was produced in EAF's and the balance predominantly by BOF's. In 1991, the United States produced about 87 million tons of raw steel. In 1991, 76 percent of the steel produced was processed through continuous casting machines rather than through ingot casting. Continuous casting is projected to account for about 84 percent in 1995. It should be noted that 1991 was not a good year for steel production. World steel production was down about 5 percent from 1990, and U.S. production was down 12 percent. Shipments to both the automobile and construction

industries were down significantly in 1991. The automobile industry is the largest single consumer of steel in the United States, and the construction industry is also a large consumer.[7]

Emphasizing the international character of the steel industry, the import share of the United States steel market, during the first half of 1991, was 8.24 million tons or 18.9 percent. Exports for the same period were 3.2 million tons.[7]

Annual steel production capacity in the United States in 1991 was about 120 million tons. High and low capacities in recent times were 160 million tons in 1977 and 112 million tons in 1988. In 1990, the steel industry in the United States was composed of approximately 300 companies, of which 83 produced raw steel at 127 locations.[8]

Table 3-1 summarizes data pertinent to the iron and steel industry to characterize the current status of the industry. Basic oxygen converters (BOP's and Q-BOP's) remain the major source of steel production, but electric arc furnaces now account for about 37 percent. Open hearth furnaces are no longer in use in the United States.

A 1991 directory of iron and steel plants in North America defines three categories of steel producers as follows:[9]

- Integrated Steel Producers are defined as those companies having blast furnace or direct reduction facilities and whose principal commercial activity is the production and sale of carbon steel.

- Specialty Producers are defined as those companies whose principal commercial activity is the production and sale of stainless steels, alloy steels, tool steels, bars, wires, pipe, etc.

- Mini-Plants or mini-mills are defined as those companies whose production is based on electric furnace-continuous caster-rod/bar mill operations, generally rolling carbon steel products--rebar, rounds, flats and small shapes.

The differences between these categories are not always clear. Some companies in all three categories use EAF's to melt steel and have continuous casters. The integrated producers are the

TABLE 3-1. SUMMARY OF CURRENT STEEL INDUSTRY FACTS[3,8]

	1991	1992	1993
U.S. percentage of world production (%)	11.6		
Total U.S. production (10^6 tons)	87	92.9	96.1
Total U.S. shipments (10^6 tons)	79	82.2	88.5
Total production by (%):			
Basic oxygen converter			
EAFs	37		
Open hearths			
U.S. raw steel capacity (10^6 tons)	120	113	110
Number of companies			
Raw steel producers	83		
Imports (10^6 tons)			
Percent by continuous casting (%)	75.8		

most distinct group because they alone produce iron from iron ore in blast furnaces or direct reduction iron (DRI) facilities. Integrated producers also use coke in blast furnaces and either produce coke on site or purchase it from coke producers. As of May 1991, there was only one DRI facility in the United States.[10] Mini-mills use only electric arc furnaces and use scrap steel as feed stock.

3.1.2.1 Integrated Producers. The integrated producers, although much fewer in number than specialty producers and mini-mills, produce the greater volume of steel. In 1990, integrated producers accounted for about 70 percent of raw steel production in the United States.[9,11] The referenced 1991 directory lists 20 integrated steel producers in the United States. However, it is not clear that all of those listed conform to the preceding definition of an integrated producer, i.e., use blast furnaces or DRI facilities and produce carbon steel. Those known to be integrated producers are listed in Table 3-2 along with other available information.[9]

3.1.2.2 Mini-Mills. The mini-mills are a growing segment of the steel-producing companies that, in 1991, accounted for more than 20 percent of production in the United States. It has been suggested that the term mini-mill is a misnomer. The steel-melting facility used by mini-mills (i.e., EAF's) can produce up to 130 tons of steel per hour, not far from the 200- to-300-tons/hr typical of a BOF.[12] Once viewed as suppliers of unsophisticated, low-quality products requiring minimal technology, mini-mills are now recognized as playing a growing technological role and for having made permanent inroads into the traditional domain of integrated producers.[13] In 1990, Nucor Corporation and North Star Steel Company, two mini-mill producers, ranked seventh and eighth, respectively, among United States steel producers. Nucor, for example, has an annual production capacity of 3 million tons, and North Star an annual capacity of about 2.5 million tons. By contrast, USX Corporation (formerly U.S. Steel Corporation), the nation's leading steel producer, shipped about 12 million tons in 1990.[9,12] The 1991 directory of iron and steel plants lists 42 mini-mill companies.

3.1.2.3 Specialty Producers. It is more difficult to characterize the specialty producers than integrated or mini-mill producers. There are more companies, a total of about 120; they produce a wide variety of specialty products; and it is difficult to ascertain the starting point in their production process from the literature. Company sizes vary widely (e.g., the number of employees number from as few as 8 to as many as 5,000) and annual capacities range from 62,000 to 1,500,000 tons of product. As a group, they operate EAF's and a host of other furnaces including annealing and reheat furnaces. By contrast, some weld or do

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TABLE 3-2. SUMMARY INFORMATION RELEVANT TO INTEGRATED STEEL PRODUCERS[a]

Company name/ company address	Products	Capacity (ton/yr)	Number of employees	Plant location[b]
ACME STEEL CO. Riverdale, IL 60627-1182 (708) 849-2500	Coke, pig iron, sheet, bars	1,000,000	2,900	IL
ARMCO Steel Company, L.P. Middletown, Ohio 45043 (513) 425-5000	Slabs, coke, chemicals, sheet, strip galvanized	4,000,000	7,600	OH, KY
BETHLEHEM STEEL CORP. Bethlehem, PA 18016-7699 (215) 694-2424	Coke, wire, rods, ingots, slabs, plates, rails, bars, billets, blooms, pig iron, chemicals, tin plate, sheet, strip galvanized			PA, MD, IN
GENEVA STEEL Provo, UT 84603 (801) 227-9090	Coke, iron ore, sheet, plate, pipe, bands, coils	1,400,000	2,700	UT
GULF STATES STEEL, INC. Gadsden, AL 35901-1935 (205) 543-6100	Coal, chemicals, plate, sheet, strip galvanized	1,800,000 Actual prod: 1,200,000	2,219	AL
INLAND STEEL INDUSTRIES, INC. Chicago, IL 60603 (219) 399-1200	Sheets, plate, coal, chemicals, bar, beam, billet			IN
LTV STEEL CO., INC. Cleveland, OH 44115 (216) 622-5000	Ingot, billet, slab, coke, tubing, pipe			OH, IN
McLOUTH STEEL Trenton, MI 48183 (313) 285-1200	Plate, sheet, strip alloy galvanized			MI

(continued)

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TABLE 3-2 (continued)

Company name/ company address	Products	Capacity (tons/yr)	Number of employees	Plant location[a]
NATIONAL STEEL CORP. Mishawaka, IN 46545 (219) 273-7000	Coal, chemicals, plate, sheet, ingot, galvanized, siding			MI, IN, IL
ROUGE STEEL CO. Dearborn, MI 48121 800-241-1580	Ingot, slab, sheet			MI
SHARON STEEL CORP. Farrell, PA 16121 (412) 981-1375	Strapping, coke pipe, tubing galvivanized, alloy	1,400,000	170	PA
USX CORP. Pittsburgh, PA 15219-4776 (412) 433-1121	Coke, pig iron, ingot, pipe, rods, plate, galvanized, alloy			AL, PA, IN, IL
WARREN CONSOLIDATED INDUST. Warren, OH 44483 (216) 841-8218	Sheet, flat rolled electrical steels	1,500,000		OH
WEIRTON STEEL CORP. Weirton, WV 26062 (304) 797-2000	Rolled sheets galvanized zinc coated			WV
WHEELING-PITTSBURGH STEEL CORP. Wheeling, WV 26003 (304) 234-2400	Coke, sheet, ingot tinplate, galvanized roofing products			OHCont.

[a] Integrated plant locations by States.

other single-function operations that do not include the onsite combustion of fuels. Products may range from a single item such as cold-drawn wire to highly specialized steels.[9] In terms of their contribution to domestic capacity and production, they are grouped with mini-mills.

3.2 INDUSTRY CHARACTERIZATION

3.2.1 An Overview of Iron and Steel Manufacturing

Figure 3-1 is a simplified flow diagram illustrating the principal steps involved in the production of steel. All of these processes, and more, are found in modern integrated steel mills. An overview of these processes is presented here. Individual processes that produce NO_x are discussed in more detail in Section 3.3 of this chapter.

3.2.1.1 Raw Materials and Preparatory Processes. With reference to Figure 3-1, the basic raw material input for the production of iron and steel is iron ore, which is reduced to metallic iron in the blast furnace. The principal iron ore beneficiating processes are pelletizing and sintering. Pelletizing is usually accomplished in specially designed furnaces located at or near iron ore mines rather than at iron and steel mills. Its purpose is to pelletize fine, low-grade ores prior to shipping to an iron and steel mill. Pelletizing is rarely practiced in an iron and steel mill.

In contrast to pelletizing, sintering is often practiced at integrated iron and steel mills. Its primary purpose is to agglomerate dusts and fines from other process, e.g., ore fines, coke fines, and flue dust, into particles with suitable mass, size, porosity, and strength to charge into the blast furnace. Fines charged to a sintering furnace differ in size from those charged to a pelletizing furnace, and they originate at the iron and steel mill rather than at the mine. Alternatively, fine particles charged into the blast furnace will be blown out by the rapid countercurrent flow of the furnace gases.

Another basic material used in the conversion of iron ore into metallic iron is coke. Coke is the primary residue that remains when a blend of pulverized coking coals is heated gradually to high temperatures, about 900 to 1,100 °C (1,650 to 2,010 °F) in the absence of air for approximately 18 hours. About 90 percent of the coke produced in the United Stated is charged to blast furnaces for the production of pig iron.[14]

The conversion of coal to coke is performed in long, narrow, slot ovens, i.e., by-product coke ovens, which are usually designed and operated to permit the separation and recovery of the volatile materials evolved from the coal during the coking

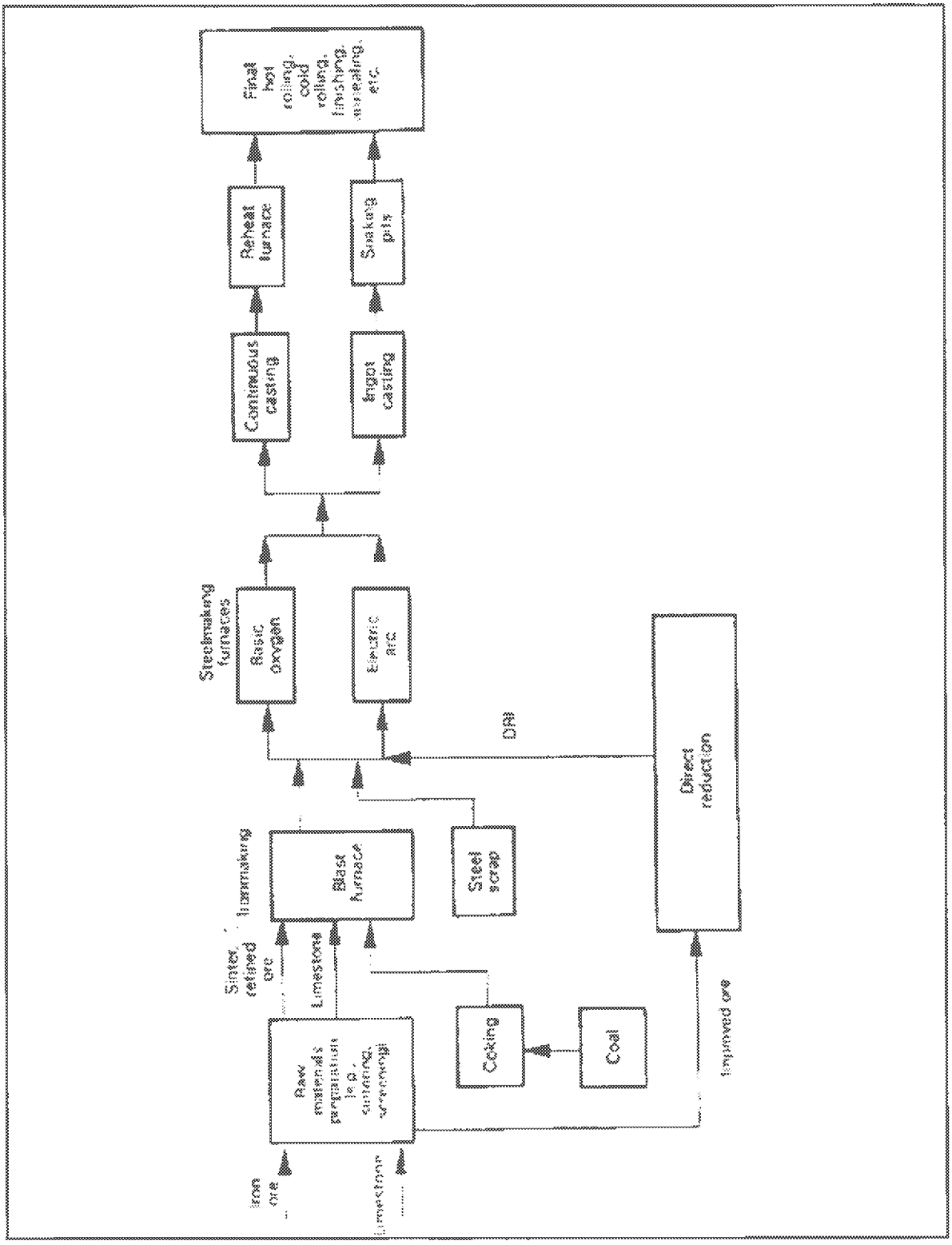

Figure 3-1. Simplified steelmaking flow chart.

process. In addition to coke, the primary product, a number of by-products may also be recovered including breeze, crude tar, crude light oil, ammonia, and coke oven gas. These may be used on site or marketed. Coke is likely to be used on site but may be marketed, coke oven gas is likely to be used on site, and breeze is likely to be recycled to the sintering process.[15]

A third raw material input to the iron and steel making process is flux. In the iron smelting process, i.e., when iron is separated from the ore by fusion in a blast furnace, a flux is used to enhance the process by combining with ash in the coke and gangue in the ore to make a fluid slag that can be readily separated from the molten iron. Selection of the proper flux for a given process is a well-established process requiring knowledge of the composition and properties of the materials involved. Limestone and/or dolomite are the fluxes used in blast furnaces. The proportions of each depend principally on the constituents of the slag and the amount of sulfur that the slag must remove.[16]

In the basic oxygen steelmaking process, lime normally is added as calcined or burnt lime or burnt dolomite. The calcium oxide in either the burnt lime or burnt dolomite fluxes the silica formed upon the oxidation of silicon in the hot metal.[17]

Often, limestone is also charged into the sinter plant to produce a precalcined or self-fluxing sinter. The use of self-fluxing sinter has both economic and performance advantages.[18]

3.2.1.2 Ironmaking. Iron ore, coke, selected fluxes (e.g., prepared limestone), and sinter are charged to the blast furnace where iron is reduced from its ore. The product of the blast furnace contains more than 90 percent iron and is referred to as pig iron or, if in a molten form, hot metal. Most of the blast furnace product is transported directly to onsite steelmaking furnaces as hot metal.

The blast furnace charge of iron-bearing materials (including iron ore, sinter, mill scale, steelmaking slag, and scrap), coke, and flux (limestone and/or dolomite) is placed in the furnace, and a blast of heated air and, in most instances, a gaseous, liquid, or powdered fuel is introduced through openings near the bottom of the furnace just above the furnace's hearth crucible. The blast of heated air burns the injected fuel and most of the coke to produce the heat required by the process and the reducing gas that removes oxygen from the ore. The reduced iron melts and pools in the bottom of the hearth. The flux combines with the impurities in the ore to produce a slag, which also melts and accumulates on top of the liquid iron. Periodically, the iron and the slag are drained from the furnace through tapping holes.[3]

4.2 NO_x EMISSIONS FROM IRON AND STEEL MILLS

Integrated iron and steel mills import three basic raw materials and process these to produce steel in a variety of compositions and forms. The conversion processes, described in Chapter 3 of this document, tend to be high-temperature processes in which large quantities of fuels are consumed. As a consequence, most of these processes are sources of NO_x emissions.

Mini-mills and specialty producers do not have the full range of processing facilities characteristically found in integrated plants. They do not, for example, produce coke or sinter for use in blast furnaces or operate blast furnaces to produce pig iron or hot metal. Instead, they may produce steel by melting scrap in an electric-arc furnace, and they may use some subset of the processes found in integrated mills to produce a variety of steel products. They, too, may use a number of high-temperature, fuel- consuming processes and produce NO_x emissions. In this section, the major sources of NO_x emissions inherent in steelmaking plants are identified along with the fuels and process temperatures characteristically used in these processes. Further, estimates of uncontrolled NO_x emissions are also given.

The following subsections discuss uncontrolled NO_x emission factors and NO_x emissions from specific iron and steel process facilities. These data appear in the literature or were provided by Section 114 responses for a variety of units, many of which cannot be easily interpreted for other conditions. These data are summarized in tabular form in Section 4.2.11 and are tabulated in Appendix A.

4.2.1 Emission Factors

NO_x emissions data in the literature relevant to iron and steel mill processes are limited. This lack of a good emissions database is reflected in the major compilations of emission factors.[6-8] Table 4-3 is a compilation of emissions factors from AP-42[6,8] and from the National Acid Precipitation Assessment Program (NAPAP).[7,8] Note that the units used for these factors are unusual and not easily interpreted or used. Also, note that their quality ratings are poor (D for AP-42 and E for NAPAP), i.e., they are based on a single observation of questionable quality or an extrapolation from another factor for a similar process. If these emission factors are to be used, it has been recommended that AP-42 factors be used whenever possible and that the NAPAP emission factors be used when AP-42 factors are unavailable.[5] These emission factors are not used in this document.

4.2.2 Coke-oven Underfiring

As described in Chapter 3, coke is made by the destructive distillation of coal in the absence of air. During distillation,

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TABLE 4-3. NITROGEN OXIDE EMISSION FACTORS FROM AP-42 AND NAPAP[a,b]

Operation/process	NO_x (lb/unit)[a,c] (AP-42)	Units	NO_x (lb/unit)[b,c] (NAPAP)	Units
Process gas				
BFG			23.0	
		10^6 ft^3 burned		
COG			80.0	
By-product coke mfg.				
Charging	0.03			
		Tons coal charged		
Pushing			0.03	
		Tons coal charged		
Quenching			0.6	
		Tons coal charged		
Underfiring			0.04	
		Tons coal charged		
Door leaks	0.01			Tons coal charged
Top-side leaks			0.01	
		Tons coal charged		
Sintering				
Windbox			0.3	
		Tons sinter produced		
Steel production				
Electric arc furnace: stack		0.1		Tons produced
Soaking pits			Neg	
		Tons produced		
BOF: Open hood-stack			0.08	
		Tons produced		
Tapping: BOF			0.02	
		Tons produced		
Continuous casting			0.05	
		Tons produced		
Heat-treating furnaces, annealing			0.1	
		Tons produced		
Coating (tin, zinc, etc.)			1.9	
		Tons produced		

[a] These factors have a D quality rating. Thus, they are based on a single observation of questionable quality or extrapolated from another factor for a similar process.

[b] These factors have an E quality rating. Thus, they are based on a single observation of questionable quality or extrapolated from another factor for a similar process.

Units are listed in the right-most column.

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furnace effluent, called BFG, is captured, cleaned, cooled, and subsequently used as a fuel in other processes. BFG contains about 1 percent hydrogen and 27 percent CO and has a heating value of about 2,540 - 3,600 kJ/Nm^3 (65 - 92 Btu/ft^3).[5]

A blast furnace typically has three or four blast furnace stoves as auxiliaries. These stoves are used to heat the blast air required by the blast furnace. They function somewhat like a regenerator in that one or more of the stoves are on blast (i.e., they are being used to heat the blast air being used by the blast furnace) while the others are being heated. They differ from a regenerator in that the source of heat is the combustion of a fuel rather than the extraction of heat from an effluent stream.

Between 2.2 and 3.5 kg of BFG are generated for each kilogram of pig iron produced in a blast furnace. About 18 to 24 percent of this gas is used to heat the checker brick in the associated stoves.[2] The remainder is used elsewhere in the plant. Because of its low heating value, the BFG used in the stoves is often enriched by the addition of fuels with a much higher calorific value such as natural gas or coke-oven gas to obtain higher blast air temperature, often in excess of 1,100 °C (2,010 °F).[18]

Blast furnace stoves are a NO_x emissions concern because they consume large quantities of fuel. However, the primary fuel is BFG, which is largely CO, has a low heating value, and contains inerts, factors that reduce flame temperature. Thus, the NO_x concentration in blast furnace stove flue gas tends to be low and the potential for NO_x reduction is considered to be small.[2]

Apparently there are no blast furnace stoves with NO_x emissions controls in the United States. The Japanese also indicate that NO_x emissions from blast furnace stoves are not a concern for the reasons noted above. They also suggest that LEA combustion can be implemented, but they do not explicitly claim to have implemented LEA.[8]

5.3.4 Basic Oxygen Furnace

The BOF is the principal steelmaking process used in the United States. In operation, the BOF is tilted to receive a charge of scrap metal and, subsequently, molten pig iron from a blast furnace. After charging, it is returned to a vertical position and blown with high-purity oxygen, which converts the charge to steel. It is finally tapped and the molten steel is poured into a transfer ladle. Following tapping, the BOF is again tilted to discharge the remaining slag. A more detailed description of the BOF facility and the oxygen steel-making

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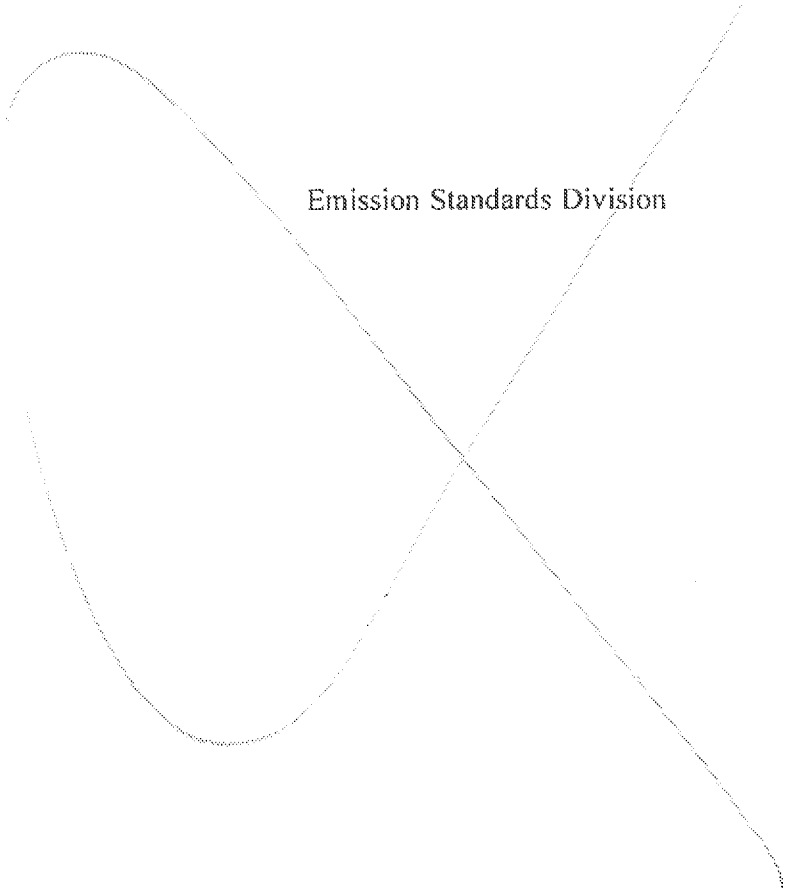
ALTERNATIVE CONTROL TECHNIQUES DOCUMENT -- NO_x EMISSIONS FROM IRON AND STEEL MILLS



Emission Standards Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards

process can be found in Chapter 3 of this document and in Reference 18.

In the BOF, oxygen is blown onto the bath at supersonic velocity (to penetrate slag and metal emulsions) where it oxidizes impurities in the bath to create steel. The oxidation of carbon produces about 467 kJ of CO per kilogram of steel (400,000 Btu/ton).[2] Typically, the off-gas, which is mainly CO, is burned in an open, water-cooled hood mounted above the BOF. These hoods admit air for combustion of the CO on an uncontrolled basis. Some newer BOF's use suppressed combustion hoods that do not admit air or burn the off-gas. In these instances, the effluent gas is flared.

The combustion of the waste gas results in the generation of NO_x. There is no information available to indicate that existing BOF's have any kind of NO_x emission controls or that any control techniques are suitable.[2]

A variation on the BOF is the Q-BOP furnace. It differs from the BOF principally in that oxygen is blown through the molten metal bath through tuyeres in the bottom of the vessel rather than onto the top surface of the bath. From a NO_x emissions and controls perspective, the two processes appear to be essentially the same, i.e., there is no indication that Q-BOP furnaces have NO_x emissions controls or that any control techniques are suitable. In each case, NO_x is generated during the oxygen blow when CO in the off-gas is combusted either at the mouth of an open, combustion-type hood or at the flare of a suppressed hood system.[19]

5.3.5 Electric Arc Furnaces

The use of electricity to melt steel scrap in the EAF transfers NO_x generation from the steel mill to a utility power plant. There is no information that NO_x emissions controls have been installed on EAF's or that suitable controls are available.

5.3.6 Reheat Furnaces

Reheat furnaces bring steel to a uniform temperature of about 1,180 to 1,340 °C (2,150 to 2,450 °F), a temperature suitable for hot working.[20] They are major fuel-consuming facilities and major sources of NO_x emissions.

LEA, LNB's, and LNB plus FGR are being used to control NO_x emissions from reheat furnaces in the United States.[9,10,11,21] Major modifications to furnace structure and refractories to install alternate burners may be required in some existing reheat furnaces. In an LEA application, the control was retrofitted to

are seldom specified. A summary of these data is tabulated below. The data in terms of lb/ton show a wide range from 0.007 to 0.70.

	ppm @ 3% O_2	lb/MMBtu	lb/ton
n(No. Samples)	2	4	16
Min. Value	284	0.22	0.007
Max. Value	395	0.59	0.70
Avg. Value	339	0.47	0.34
Std. Dev.		0.17	0.28

4.2.4 Blast Furnaces and Blast Furnace Stoves

The blast furnace is fueled by the combustion of coke that, along with iron ore and flux, is a component of its charge, and the off-gas is recovered and burned for its fuel value. It is a closed unit that does not have atmospheric emissions. However, the associated blast furnace stoves do generate NO_x emissions. These stoves, typically three or four for each blast furnace, burn the blast furnace gas (BFG) to preheat the combustion air supplied to the blast furnace. The BFG has a low heating value ranging from 3.0 to 3.5 MJ/Nm^3 (80 to 95 Btu/ft^3).[5] More recently, values ranging from a low of 2.5 MJ/Nm^3 (65 Btu/ft^3) have been reported with changes in blast furnace burdens cited as the cause of the deterioration.[16] Blast furnace gas burns with a low flame temperature. Its combustible component is carbon monoxide, which burns clean.[6] However, the BFG is often enriched with other fuels (e.g., natural gas or COG) to obtain blast-air temperatures as high as 1,100 °C (2,010 °F).[5]

The available uncontrolled NO_x emissions data for blast furnace stoves are tabulated in Appendix A. These data vary widely in terms oflb/MMBtu and lb/ton, and much of these data are incomplete, i.e., test conditions are seldom specified. A summary of these data is shown below.

	ppm @ 3% O_2	lb/MMBtu	lb/ton
n(No. Samples)	1	11	10
Min. Value		0.002	0.003
Max. Value		0.057	0.072
Avg. Value	28	0.021	0.037
Std. Dev.		0.019	0.022

4.2.5 Basic Oxygen Furnace

The basic oxygen process of steelmaking is an exothermic process that does not require the burning of fossil fuels. The process does produce off-gases, principally carbon monoxide, which are usually burned prior to discharge into the atmosphere. Some newer BOF facilities use suppressed combustion hoods, which suppress the influx of air, and the off-gases are subsequently flared. A potential for NO_x generation does exist during the combustion of waste gases. Nitrogen oxides production from this process has been estimated to range from 30 to 80 ppm, or 180 to 500 ng NO_x/kg (0.36 to 1 lb NO_x/ton) of steel produced.[19]

Appendix A presents NO_x emissions data for BOFs, including Q-BOPs, and these data are summarized below. Data for which the status of the furnace is unknown (i.e., whether or not the furnace is in an O_2 blow period) are not included in the summary. A wide range in terms of ppm@ 3%O_2 is reported (18-180) but in terms of lb/ton the range is much narrower (0.042-0.22).

During O_2 Blow Period

	ppm (avg)	ppm @ 3% O_2	lb/ton
n(No. Samples)	12	7	7
Min. Value	12.3	18	0.042
Max. Value	84.0	180	0.222
Avg. Value	24.0	58	0.119
Std. Dev.	19.6	56	0.059

During Non O_2 Blow Period

	ppm (avg)	ppm @ 3% O_2	lb/ton
n(No. Samples)	2	2	-
Min. Value	14.3	200.	-
Max. Value	14.5	366.	-
Avg. Value	14.4	283.	-

4.2.6 Electric-Arc Furnace

The electric arc furnace largely transfers the generation of NO_x emissions from the steelmelting facility to a utility plant where it is easier to control. The only use of fossil fuels in the electric arc facility is for scrap preheating, which may or may not be practiced. However, some EAFs also fire oxy-fuel burners in addition to electric arcs during meltdown.[17] The available NO_x emissions data, presented in Appendix A and summarized below, suggest that concurrent oxy-fuel firing during meltdown does increase NO_x emissions above the emissions from electric-arc melting alone as NO_x increased from 12 to 98 ppm. The range of NO_x emissions is narrow from 0.5 - 0.6 lb/ton and 83 - 100 lb/heat.

APPENDIX A-4. UNCONTROLLED NO_x EMISSIONS FROM IRON AND STEEL MILL PROCESS FACILITIES

Basic Oxygen Furnaces (BOF)

Furn.	Heat In (ppm (lb))	NO_x emissions	Emissions units	Production (tons/hr)	Test date	Ref (*)	Comments
B_1		58 169 135.1 0.231	ppm (avg) ppm (peak) lb/hr lb/ton	935	5/80	1,9(D)	
B_2		26 0.084	ppm @ 12.1% O_2 lb/ton		12/80, 11/80	2,9(D)	
B_3		12.3 0.042	ppm @ 8.9% O_2 lb/ton		7/80	1,9(N)	Some uncontrolled
B_4		12.7 24. 0.11	ppm @ 16.6% O_2 lb/hr lb/ton		10/80	2	Average emissions over 6 cycles
B_5		21.4	ppm		11/81	2	Average emissions over 8 cycles
B_6		23.2	ppm @ 18.8% O_2		6/82	2	Average emissions over 6 cycles
B_7		10.3	ppm @ 16.4% O_2		6/82	2	Average emissions over 6 cycles
B_8		17.9 45.0 (82.8 0.180	ppm (avg) ppm (peak) lb/ton lb/hr	460	8/82	3(E)	
B_9		14.6 43.0 82.2 0.131	ppm (avg) ppm (peak) lb/hr lb/ton	410	8/82	3(E)	

0.22

0.04

0.15

0.15

B-20

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APPENDIX A-4 (continued)

Basic Oxygen Furnaces (BOF)

Fuel	Heat In (mmBtu/hr)	NO_x Emissions	Emissions with	Production (tons/hr)	Test Date	Ref. (#)	Comments
O_2		16.3 NR NR 0.121	ppm (avg) ppm (peak) lb/hr lb/ton	414	8/92	9(R)	
		8.6 13.9 0.034	ppm (avg) lb/hr lb/ton	326	7/93	9(Q)	
		6.6 8.2 0.025	ppm (avg) lb/hr lb/ton	326	8/93	9(Q)	
		7.0 8.53 0.026	ppm (avg) lb/hr lb/ton	326	8/93	9(Q)	
Basic Oxygen Furnaces (CBOF)							
O_2		29.5	ppm @ 3% O_2	225	6/92	4,9(E)	During O_2 blow Period
O_2		29.5	ppm @ 3% O_2	225	6/92	4,9(E)	During O_2 blow Period
		11.3 358	ppm ppm @ 3% O_2	225	6/92	4,9(A)	Duration Non O_2 Blow Period
		14.9 280	ppm ppm @ 3% O_2	225	6/92	4,9(B)	During Non O_2 blow Period

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BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF	)	PETITION NO. VI-2017-6
	)	
BP AMOCO CHEMICAL COMPANY	)	ORDER RESPONDING TO
TEXAS CITY CHEMICAL PLANT	)	PETITION REQUESTING
GALVESTON COUNTY, TEXAS	)	OBJECTION TO THE ISSUANCE OF
	)	TITLE V OPERATING PERMIT
PERMIT NO. O1513	)	
	)	
ISSUED BY THE TEXAS COMMISSION ON	)	
ENVIRONMENTAL QUALITY	)	
	)	

ORDER GRANTING IN PART AND DENYING IN PART A PETITION FOR OBJECTION TO PERMIT

I. INTRODUCTION

The U.S. Environmental Protection Agency (EPA or the Agency) received a petition dated April 4, 2017, (the Petition) from the Environmental Integrity Project and Sierra Club (the Petitioners), pursuant to section 505(b)(2) of the Clean Air Act (CAA or Act), 42 United States Code (U.S.C.) § 7661d(b)(2). The Petition requests that the EPA Administrator object to operating permit No. O1513 (the Permit) issued by the Texas Commission on Environmental Quality (TCEQ) to the BP Amoco Chemical Company's Texas City Chemical Plant (BP Amoco or the facility) in Galveston County, Texas. The operating permit was issued pursuant to title V of the CAA, 42 U.S.C. §§ 7661–7661f, and Title 30, Chapter 122 of the Texas Administrative Code (TAC). *See also* 40 Code of Federal Regulations (C.F.R.) part 70 (title V implementing regulations). This type of operating permit is also referred to as a title V permit or part 70 permit.

Based on a review of the Petition and other relevant materials, including the Permit, the permit record, and relevant statutory and regulatory authorities, and as explained in Section IV of this Order, the EPA grants in part and denies in part the Petition requesting that the EPA Administrator object to the Permit. Specifically, the EPA grants portions of Claim B, as well as Claim C, and denies the rest of the claims.

II. STATUTORY AND REGULATORY FRAMEWORK

A. Title V Permits

Section 502(d)(l) of the CAA, 42 U.S.C. § 766la(d)(1), requires each state to develop and submit to the EPA an operating permit program to meet the requirements of title V of the CAA and the EPA's implementing regulations at 40 C.F.R. part 70. The state of Texas submitted a title V program governing the issuance of operating permits on September 17, 1993. The EPA Granted

interim approval of Texas's title V operating permit program in 1996, and granted full approval in 2001. *See* 61 Fed. Reg. 32693 (June 25, 1996) (interim approval effective July 25, 1996); 66 Fed. Reg. 63318 (December 6, 2001). This program, which became effective on November 30, 2001, is codified in 30 TAC Chapter 122.

All major stationary sources of air pollution and certain other sources are required to apply for and operate in accordance with title V operating permits that include emission limitations and other conditions as necessary to assure compliance with applicable requirements of the CAA, including the requirements of the applicable implementation plan. 42 U.S.C. §§ 7661a(a), 7661b, 7661c(a). The title V operating permit program generally does not impose new substantive air quality control requirements, but does require permits to contain adequate monitoring, recordkeeping, reporting, and other requirements to assure compliance with applicable requirements. 57 Fed. Reg. 32250, 32251 (July 21, 1992); *see* 42 U.S.C. § 7661c(c). One purpose of the title V program is to "enable the source, States, EPA, and the public to understand better the requirements to which the source is subject, and whether the source is meeting those requirements." 57 Fed. Reg. at 32251. Thus, the title V operating permit program is a vehicle for compiling the air quality control requirements as they apply to the source's emission units and for providing adequate monitoring, recordkeeping, and reporting to assure compliance with such requirements.

B. Review of Issues in a Petition

State and local permitting authorities issue title V permits pursuant to their EPA-approved title V programs. Under CAA § 505(a) and the relevant implementing regulations found at 40 C.F.R. § 70.8(a), states are required to submit each proposed title V operating permit to the EPA for review. 42 U.S.C. § 7661d(a). Upon receipt of a proposed permit, the EPA has 45 days to object to final issuance of the proposed permit if the EPA determines that the proposed permit is not in compliance with applicable requirements under the Act. 42 U.S.C. § 7661d(b)(1); *see also* 40 C.F.R. § 70.8(c). If the EPA does not object to a permit on its own initiative, any person may, within 60 days of the expiration of the EPA's 45-day review period, petition the Administrator to object to the permit. 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(d).

The petition shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided by the permitting authority (unless the petitioner demonstrates in the petition to the Administrator that it was impracticable to raise such objections within such period or unless the grounds for such objection arose after such period). 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(d). In response to such a petition, the Act requires the Administrator to issue an objection if a petitioner demonstrates that a permit is not in compliance with the requirements of the Act. 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(c)(1).[1] Under

[1] *See also New York Public Interest Research Group, Inc. v. Whitman*, 321 F.3d 316, 333 n.11 (2d Cir. 2003) (*NYPIRG*).

section 505(b)(2) of the Act, the burden is on the petitioner to make the required demonstration to the EPA.[2]

The petitioner's demonstration burden is a critical component of CAA § 505(b)(2). As courts have recognized, CAA § 505(b)(2) contains both a "discretionary component," under which the Administrator determines whether a petition demonstrates that a permit is not in compliance with the requirements of the Act, and a nondiscretionary duty on the Administrator's part to object where such a demonstration is made. *Sierra Club v. Johnson*, 541 F.3d at 1265–66 ("[I]t is undeniable [that CAA § 505(b)(2)] also contains a discretionary component: it requires the Administrator to make a judgment of whether a petition demonstrates a permit does not comply with clean air requirements."); *NYPIRG*, 321 F.3d at 333. Courts have also made clear that the Administrator is only obligated to grant a petition to object under CAA § 505(b)(2) if the Administrator determines that the petitioner has demonstrated that the permit is not in compliance with requirements of the Act. *Citizens Against Ruining the Environment*, 535 F.3d at 677 (stating that § 505(b)(2) "clearly obligates the Administrator to (1) determine whether the petition demonstrates noncompliance and (2) object *if* such a demonstration is made" (emphasis added)).[3] When courts have reviewed the EPA's interpretation of the ambiguous term "demonstrates" and its determination as to whether the demonstration has been made, they have applied a deferential standard of review. *See, e.g.*, *MacClarence*, 596 F.3d at 1130–31.[4] Certain aspects of the petitioner's demonstration burden are discussed in the following paragraph. A more detailed discussion can be found in *In the Matter of Consolidated Environmental Management, Inc., Nucor Steel Louisiana*, Order on Petition Nos. VI-2011-06 and VI-2012-07 at 4–7 (June 19, 2013) (*Nucor II Order*).

The EPA considers a number of criteria in determining whether a petitioner has demonstrated noncompliance with the Act. *See generally Nucor II Order* at 7. For example, one such criterion is whether the petitioner has addressed the state or local permitting authority's decision and reasoning. The EPA expects the petitioner to address the permitting authority's final decision, and the permitting authority's final reasoning (including the state's response to comments), where these documents were available during the timeframe for filing the petition. *See MacClarence*, 596 F.3d at 1132–33.[5] Another factor the EPA examines is whether a petitioner has provided the relevant analyses and citations to support its claims. If a petitioner does not, the

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[2] *WildEarth Guardians v. EPA*, 728 F.3d 1075, 1081–82 (10th Cir. 2013); *MacClarence v. EPA*, 596 F.3d 1123, 1130–33 (9th Cir. 2010); *Sierra Club v. EPA*, 557 F.3d 401, 405–07 (6th Cir. 2009); *Sierra Club v. Johnson*, 541 F.3d 1257, 1266–67 (11th Cir. 2008); *Citizens Against Ruining the Environment v. EPA*, 535 F.3d 670, 677–78 (7th Cir. 2008); *cf. NYPIRG*, 321 F.3d at 333 n.11.

[3] *See also Sierra Club v. Johnson*, 541 F.3d at 1265 ("Congress's use of the word 'shall' . . . plainly mandates an objection *whenever* a petitioner demonstrates noncompliance." (emphasis added)).

[4] *See also Sierra Club v. Johnson*, 541 F.3d at 1265–66; *Citizens Against Ruining the Environment*, 535 F.3d at 678.

[5] *See also, e.g.*, *Finger Lakes Zero Waste Coalition v. EPA*, 734 Fed. App'x *11, *15 (2d Cir. 2018) (summary order); *In the Matter of Noranda Alumina, LLC*, Order on Petition No. VI-2011-04 at 20–21 (December 14, 2012) (denying a title V petition issue where petitioners did not respond to the state's explanation in response to comments or explain why the state erred or why the permit was deficient); *In the Matter of Kentucky Syngas, LLC*, Order on Petition No. IV-2010-9 at 41 (June 22, 2012) (denying a title V petition issue where petitioners did not acknowledge or reply to the state's response to comments or provide a particularized rationale for why the state erred or the permit was deficient); *In the Matter of Georgia Power Company*, Order on Petitions at 9–13 (January 8, 2007) (*Georgia Power Plants Order*) (denying a title V petition issue where petitioners did not address a potential defense that the state had pointed out in the response to comments).

EPA is left to work out the basis for the petitioner's objection, contrary to Congress's express allocation of the burden of demonstration to the petitioner in CAA § 505(b)(2). *See MacClarence*, 596 F.3d at 1131 ("[T]he Administrator's requirement that [a title V petitioner] support his allegations with legal reasoning, evidence, and references is reasonable and persuasive.").[6] Relatedly, the EPA has pointed out in numerous previous orders that general assertions or allegations did not meet the demonstration standard. *See, e.g.*, *In the Matter of Luminant Generation Co., Sandow 5 Generating Plant*, Order on Petition Number VI-2011-05 at 9 (January 15, 2013).[7] Also, the failure to address a key element of a particular issue presents further grounds for the EPA to determine that a petitioner has not demonstrated a flaw in the permit. *See, e.g.*, *In the Matter of EME Homer City Generation LP and First Energy Generation Corp.*, Order on Petition Nos. III-2012-06, III-2012-07, and III-2013-02 at 48 (July 30, 2014).[8]

The information that the EPA considers in determining whether to grant or deny a petition submitted under 40 C.F.R. § 70.8(d) generally includes, but is not limited to, the administrative record for the proposed permit and the petition, including attachments to the petition. 40 C.F.R. § 70.13. The administrative record for a particular proposed permit includes the draft and proposed permits; any permit applications that relate to the draft or proposed permits; the statement required by § 70.7(a)(5) (sometimes referred to as the 'statement of basis'); any comments the permitting authority received during the public participation process on the draft permit; the permitting authority's written responses to comments, including responses to all significant comments raised during the public participation process on the draft permit; and all materials available to the permitting authority that are relevant to the permitting decision and that the permitting authority made available to the public according to § 70.7(h)(2). *Id.* If a final permit and a statement of basis for the final permit are available during the Agency's review of a petition on a proposed permit, those documents may also be considered when determining whether to grant or deny the petition. *Id.*

If the EPA grants a title V petition, a permitting authority may address the EPA's objection by, among other things, providing the EPA with a revised permit. *See, e.g.*, 40 C.F.R. § 70.7(g)(4); *see generally* 81 Fed. Reg. 57822, 57842 (August 24, 2016) (describing post-petition procedures); *Nucor II Order* at 14–15 (same). In some cases, the permitting authority's response to an EPA objection may not involve a revision to the permit terms and conditions themselves, but may instead involve revisions to the permit record. For example, when the EPA has issued a title V objection on the ground that the permit record does not adequately support the permitting decision, it may be acceptable for the permitting authority to respond only by providing an additional rationale to support its permitting decision.

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[6] *See also In the Matter of Murphy Oil USA, Inc.*, Order on Petition No. VI-2011-02 at 12 (September 21, 2011) (denying a title V petition claim where petitioners did not cite any specific applicable requirement that lacked required monitoring); *In the Matter of Portland Generating Station*, Order on Petition at 7 (June 20, 2007) (*Portland Generating Station Order*).

[7] *See also Portland Generating Station Order* at 7 ("[C]onclusory statements alone are insufficient to establish the applicability of [an applicable requirement]."); *In the Matter of BP Exploration (Alaska) Inc., Gathering Center #1*, Order on Petition Number VII-2004-02 at 8 (April 20, 2007); *Georgia Power Plants Order* at 9–13; *In the Matter of Chevron Products Co., Richmond, Calif. Facility*, Order on Petition No. IX-2004-10 at 12, 24 (March 15, 2005).

[8] *See also In the Matter of Hu Honua Bioenergy*, Order on Petition No. IX-2011-1 at 19–20 (February 7, 2014); *Georgia Power Plants Order* at 10.

When the permitting authority revises a permit or permit record in order to resolve an EPA objection, it must go through the appropriate procedures for that revision. The permitting authority should determine whether its response is a minor modification or a significant modification to the title V permit, as described in 40 C.F.R. § 70.7(e)(2) and (4) or the corresponding regulations in the state's EPA-approved title V program. If the permitting authority determines that the modification is a significant modification, then the permitting authority must provide for notice and opportunity for public comment for the significant modification consistent with 40 C.F.R. § 70.7(h) or the state's corresponding regulations.

In any case, whether the permitting authority submits revised permit terms, a revised permit record, or other revisions to the permit, and regardless of the procedures used to make such revision, the permitting authority's response is generally treated as a new proposed permit for purposes of CAA § 505(b) and 40 C.F.R. § 70.8(c) and (d). *See Nucor II Order* at 14. As such, it would be subject to the EPA's 45-day review per CAA § 505(b)(1) and 40 C.F.R. § 70.8(c), and an opportunity for the public to petition under CAA § 505(b)(2) and 40 C.F.R. § 70.8(d) if the EPA does not object during its 45-day review period.

When a permitting authority responds to an EPA objection, it may choose to do so by modifying the permit terms or conditions or the permit record with respect to the specific deficiencies that the EPA identified; permitting authorities need not address elements of the permit or the permit record that are unrelated to the EPA's objection. As described in various title V petition orders, the scope of the EPA's review (and accordingly, the appropriate scope of a petition) on such a response would be limited to the specific permit terms or conditions or elements of the permit record modified in that permit action. *See In The Matter of Hu Honua Bioenergy, LLC*, Order on Petition No. VI-2014-10 at 38–40 (September 14, 2016); *In the Matter of WPSC, Weston*, Order on Petition No. V-2006-4 at 5–6, 10 (December 19, 2007).

C. New Source Review

The major New Source Review (NSR) program is comprised of two core types of preconstruction permit requirements for major stationary sources. Part C of title I of the CAA establishes the Prevention of Significant Deterioration (PSD) program, which applies to new major stationary sources and major modifications of existing major stationary sources for pollutants for which an area is designated as attainment or unclassifiable for the national ambient air quality standards (NAAQS) and for other pollutants regulated under the CAA. 42 U.S.C. §§ 7470–7479. Part D of title I of the Act establishes the major nonattainment NSR (NNSR) program, which applies to new major stationary sources and major modifications of existing major stationary sources for those NAAQS pollutants for which an area is designated as nonattainment. 42 U.S.C. §§ 7501–7515. The EPA has two largely identical sets of regulations implementing the PSD program. One set, found at 40 C.F.R. § 51.166, contains the requirements that state PSD programs must meet to be approved as part of a state implementation plan (SIP). The other set of regulations, found at 40 C.F.R. § 52.21, contains the EPA's federal PSD program, which applies in areas without a SIP-approved PSD program. The EPA's regulations specifying requirements for state NNSR programs are contained in 40 C.F.R. § 51.165.

While parts C and D of title I of the Act address the major NSR program for major sources, section 110(a)(2)(C) addresses the permitting program for new and modified minor sources and for minor modifications to major sources. The EPA commonly refers to the latter program as the "minor NSR" program. States must also develop minor NSR programs to, along with the major source programs, attain and maintain the NAAQS. The federal requirements for state minor NSR programs are outlined in 40 C.F.R §§ 51.160 through 51.164. These federal requirements for minor NSR programs are less prescriptive than those for major sources, and, as a result, there is a larger variation of requirements in EPA-approved state minor NSR programs than in major source programs.

The EPA has approved Texas's PSD, NNSR, and minor NSR programs as part of its SIP. *See* 40 C.F.R. § 52.270(c) (identifying EPA-approved regulations in the Texas SIP). Texas's major and minor NSR provisions, as incorporated into Texas's EPA-approved SIP, are contained in portions of 30 TAC Chapters 116 and 106.

III. BACKGROUND

A. The BP Amoco Texas City Chemical Plant Facility

BP Amoco's Texas City Chemical Plant, located in Texas City, Galveston County, Texas, consists of six major production units: Paraxylene Complex, Polybutene Unit, No. 1 Metaxylene Unit, No. 2 Metaxylene Unit, Propylene Concentration Unit, and Chemical Docks. The facility is a major source of volatile organic compounds, nitrogen oxides, carbon monoxide, hazardous air pollutants, and greenhouse gases, and is subject to title V of the CAA. Emission units within the facility are also subject to the PSD program, other preconstruction permitting requirements, and various New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP).

B. Permitting History

BP Amoco first obtained a title V permit for the Texas City Chemical Plant in 2004, which was first renewed in 2009. On November 14, 2013, BP Amoco submitted an application for a renewal title V permit. TCEQ noticed the Draft Permit and Statement of Basis on June 12, 2014, subject to a public comment period from June 12, 2014, until July 14, 2014. On December 20, 2016, TCEQ transmitted the Proposed Permit, along with its Response to Comments (RTC), to the EPA for its 45-day review. The EPA's 45-day review period ended on February 3, 2017, during which time the EPA did not object to the Proposed Permit. TCEQ issued the final title V permit for the Texas City Chemical Plant on February 15, 2017 (Final Permit).

C. Timeliness of Petition

Pursuant to the CAA, if the EPA does not object to a proposed permit during its 45-day review period, any person may petition the Administrator within 60 days after the expiration of the 45-day review period to object. 42 U.S.C § 7661d(b)(2). The EPA's 45-day review period expired on February 3, 2017. Thus, any petition seeking the EPA's objection to the Proposed Permit was

due on or before April 4, 2017. The Petition was received April 4, 2017, and, therefore, the EPA finds that the Petitioners timely filed the Petition.

IV. DETERMINATIONS ON CLAIMS RAISED BY THE PETITIONERS

Claim A: The Petitioners Claim That "The Proposed Permit Fails to Establish a Compliance Schedule for BP to Obtain a Federally-Approved Major Source Permit."

Petitioners' Claim: Claim A concerns Flexible Permit No. 1176, which is incorporated by reference into the source's title V permit. This claim turns on the Petitioners' characterization of the flexible permit as a "state-only" permit because: "At the time BP's flexible permit was issued, Texas's minor source flexible permit program rules were not part of Texas's federally-approved [SIP]." Petition at 5.[9]

The Petitioners go on to assert: "The Proposed Permit is deficient because it fails to establish a compliance schedule for BP to apply for and obtain a federally-approved major source preconstruction permit for projects authorized by BP's State-only Flexible Permit No. 1176." *Id.*

As the Petitioners explain, a source's title V permit must include a compliance schedule if the source has failed to comply with an applicable requirement at the time of title V permit issuance. *Id.* (citing 42 U.S.C. §§ 7661b(b), 7661c(a); 40 C.F.R. §§ 70.5(c)(8)(iii)(C), 70.6(c)(3); 30 TAC § 122.142(e)). The Petitioners claim that the Texas SIP required BP Amoco to obtain preconstruction authorizations for projects at the facility through the issuance, amendment, or alteration of an NSR permit issued under 30 TAC § 116, Subchapter B. *Id.* at 6 (citing 30 TAC §§ 116.110, 116.111, 116.116). The Petitioners assert that these Subchapter B rules "require BP to apply BACT to each new and modified facility and to obtain a preconstruction authorization before commencing any project that would increase actual emissions from any existing unit, even if the actual increases could be maintained below previously permitted allowables." *Id.* The Petitioners claim that, contrary to these requirements, the facility "failed to 'obtain SIP approved authorizations for flexible permit changes made to the Texas City Chemical Plant.'" *Id.* at 6 (quoting RTC at 22–23). The Petitioners assert that this failure amounted to a violation of the Texas SIP and the CAA. *Id.* at 7. Therefore, the Petitioners contend that the title V permit must include a compliance schedule to remedy this alleged violation. *Id.* at 9.

The Petitioners note that BP Amoco previously submitted a permit application to convert Flexible Permit No. 1176 into a SIP-approved Subchapter B permit (known as a "de-flex" application). *Id.* at 7. However, the Petitioners state that, after the close of the comment period on the Draft Permit, BP Amoco withdrew this de-flex application and submitted a different application to renew its flexible permit under flexible permit rules that are now SIP-approved. *Id.*

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[9] *See also id.* at 6 (citing 42 U.S.C. 7410(i); 79 FR 40666, 40667–68 (July 14, 2014); Objection to Federal Operating Permit No. O1227, Goodyear Tire & Rubber Company, Houston Chemical Plant (January 8, 2010) (*Goodyear Objection Letter*) ("[T]he terms and conditions of flexible permits based upon the requirements of 30 TAC Chapter 116, Subchapter G must be identified as State-only terms and conditions, pursuant to 40 CFR § 70.6(b)(2).") (quotation in Petition)). The EPA notes that this January 8, 2010 objection was issued under authority delegated by the EPA Administrator to Region 6 to object during the EPA's 45-day review period. The objection letter is available at *https://www.tceq.texas.gov/assets/public/permitting/air/Announcements/epa_goodyear_O1227.pdf.*

at 7–8. The Petitioners assert that this most recent flexible permit application cannot resolve the failures alleged in the Petition because, according to the Petitioners, "federally-approved flexible permits may only be issued to minor sources." *Id.* at 8 (citing *Environmental Integrity Project v. EPA*, 2015 610 Fed. Appx. 409 (5th Cir. 2015) (*Flex II*), along with various filings by Texas associated with related litigation). Thus, in order to remedy the alleged violation, the Petitioners assert that the "Proposed Permit must be revised to establish a schedule for BP to obtain a federally-approved major source permit for units covered by its State-only Flexible Permit." *Id.* at 9.

The Petitioners note that TCEQ, in responding to comments on the Draft Permit, stated: "[TCEQ] agrees that BP should obtain SIP approved authorizations for flexible permit changes made to the Texas City Chemical Plant." *Id.* (quoting RTC at 22–23). The Petitioners further assert that TCEQ agreed to revise the Permit to include such a requirement, but that TCEQ failed to carry through on this commitment in the Proposed Permit, which does not contain the language that TCEQ agreed to include. *Id.* at 9–10.

EPA's Response: For the following reasons, the EPA denies the Petitioners' request for an objection on this claim.

The only basis for objection identified in the Petition is the claim that the Permit must contain a compliance schedule because BP Amoco allegedly relied on state-only Flexible Permit No. 1176 to authorize various unidentified and undescribed projects. On this issue, the Petitioners have not demonstrated that a compliance schedule is necessary.

The EPA's regulations and TCEQ's EPA-approved regulations provide that a compliance schedule is required "for sources that are not in compliance with all applicable requirements at the time of permit issuance." 40 C.F.R. § 70.5(c)(8); *see also id.* § 70.6(c); 30 TAC §§ 122.132(d)(iii), 122.142(d)(1). However, the EPA will not object to a permit where the Petitioners have provided no specific evidence to demonstrate that the facility is not in compliance with applicable requirements of the Act. *In the Matter of Bunge North American, Inc.*, Order on Petition No. VI-2016-02 at 6–7 (June 7, 2017) (citing *Georgia Power Plants Order* at 9–10). The demonstration requirement is particularly important with respect to the inclusion of a compliance schedule in light of the interplay between compliance schedules and the Agency's enforcement prerogatives.[10]

[10] *See Sierra Club v. EPA*, 557 F.3d 401, 411–412 (6th Cir. 2009) (upholding EPA's denial of petition for compliance schedule where enforcement action had been commenced and settled without admission of liability) Even where there is evidence in the record that an enforcement action is underway (which the Petitioners have not presented here), the EPA has in the past applied a multi-factored analysis to determine whether a compliance schedule is warranted: (1) the kind and quality of information underlying the Agency's original finding that a prior violation occurred, (2) the information the petitioner puts forward in addition to the Agency's enforcement actions, (3) the types of factual and legal issues that remain in dispute, (4) the amount of time that has lapsed between the original decision and the current one and (5) the likelihood that a pending enforcement case could resolve some of those issues. *See id.* at 406–407 (upholding these factors as a reasonable interpretation of 42 U.S.C. § 7661d(b)(2)); *accord Sierra Club v. Johnson*, 541 F.3d 1257, 1267-69 (11th Cir. 2008) (initiation of enforcement action for PSD violation is not in and of itself sufficient to demonstrate that compliance schedule is warranted).

Here, the Petitioners have failed to demonstrate that there are applicable requirements with which the facility was not in compliance at the time of permit issuance. The Petitioners suggest that BP Amoco failed to obtain the correct type of preconstruction authorizations at various times in the past based on its reliance on the state-only flexible permit. However, the Petitioners provide only generic references to "projects authorized by BP's State-only Flexible Permit No. 1176," Petition at 5, and do not discuss or describe *any* specific changes to the facility that were not properly authorized.[11] Accordingly, the Petitioners have not demonstrated that the facility failed to obtain the required preconstruction authorizations for any particular projects or that the NSR authorizations for any emission unit are incomplete or fail to comply with the SIP. The Petitioners accordingly have not demonstrated that the source is not in compliance with any particular applicable requirement that should have applied to a particular emission unit. *See* 40 C.F.R. § 70.2 (defining "applicable requirement[s]" "as they apply to emission units"); *see also In the Matter of ExxonMobil Baytown Refinery*, Order on Petition No. VI-2016-14, at 17–18 (April 2, 2018). Accordingly, the Petitioners' claim requesting a compliance schedule is denied.[12]

Nonetheless, the EPA agrees with the Petitioners' characterization of Flexible Permit No. 1176 as a "state-only" authorization, as this permit was issued pursuant to rules that were not approved by the EPA into the Texas SIP. Since at least 2007, the EPA has consistently described this type of flexible permit as "state-only" and not federally enforceable. Notably, when the EPA approved the Texas flexible permitting program into the SIP in 2014, the EPA explained:

> [T]the commenters appear to be implying that this approval [of the modern Texas flexible permits program] will transform state-only flexible permits issued since 1994 into federally approved permits upon the effective date of this rule. This is not the case and the EPA strongly rejects any suggestion to the contrary[.]
>
> The state established and submitted for EPA approval a Flexible Permit Program in 1994. As described in detail below, the Flexible Permit Program we are conditionally approving today consists of 18 revisions to the Texas Administrative Code presented to the EPA in 7 submittals between 1994 and 2013 and contains new provisions that were never in any earlier version of the Flexible Permit Program submitted to the EPA. Those provisions could not have been used as a legal basis for establishing terms and conditions of state-only permits issued in the 1990s. Because those permits were not issued under the regulations that we are approving today, there can be no assurance that the state-only permits fully comply with all elements of the Flexible Permits Program we are approving today. Accordingly, today's action cannot make those state-only permits federally

[11] For example, the Petitioners do not provide any description of the emission units at issue, the projects themselves, any emissions increases associated with such projects, or how specific regulatory requirements (such as BACT) should have been applied to these projects.

[12] In concluding that the Petitioners have not met their burden to demonstrate a flaw in the title V permit, the EPA is not making any judgment regarding the propriety of BP Amoco's reliance on the flexible permitting process with respect to any past or future modifications to the facility. To the extent that a facility relied or relies on a state-only flexible permit to authorize a construction project, rather than following the otherwise applicable NSR requirements in the Texas SIP, this type of compliance issue should be addressed through the appropriate title I permitting channels or enforcement actions.

> approved unless and until a permit is reissued under the authority of the program being approved today with terms and conditions defined by that program.

79 Fed. Reg. 40666, 40668 (July 14, 2014). Additionally, TCEQ has acknowledged:

> A flexible permit issued or renewed prior to September 12, 2014 is a valid state permit. However, it is not a SIP approved permit. A flexible permit issued or renewed prior to September 12, 2014 *may be re-evaluated* under the current 30 TAC Chapter 116, Subchapter G requirements *to become* SIP approved.

TCEQ, Air Permit Reviewer Reference Guide: Flexible Permit Application Review Summary, APDG 6280v2 (Revised December 2014) (emphasis added).

Moreover, as the Petitioners briefly acknowledge, the EPA has objected to the issuance of title V permits incorporating these state-only permits on nearly 20 occasions. *E.g.*, *Goodyear Objection Letter*. These objections were based in part on 40 C.F.R. § 70.6(b)(2), which mandates that "the permitting authority shall specifically designate as not being federally enforceable under the Act any terms and conditions included in the permit that are not required under the Act or under any of its applicable requirements," such as an EPA-approved SIP. Accordingly, on numerous occasions between 2009 and 2011, the EPA directed TCEQ: "[T]he terms and conditions of flexible permits based upon the requirements of 30 TAC Chapter 116, Subchapter G must be identified as State-only terms and conditions, pursuant to 40 CFR § 70.6(b)(2)." *E.g.*, *Goodyear Objection Letter*.

Here, it can hardly be contested that the November 13, 2013 version of Flexible Permit No. 1176, as incorporated into the current title V permit, is a state-only authorization. It was, as the Petitioners indicate, issued under regulations that were not part of the EPA-approved Texas SIP.[13] However, the title V permit for BP Amoco currently incorporates Flexible Permit No. 1176 without qualification, suggesting that it is a federally enforceable requirement of the title V permit. *See* Final Permit at 12 (Special Condition 20), 224.[14] This plainly contravenes the requirement that non-federally enforceable requirements be designated as such. 40 C.F.R. § 70.6(b)(2). This requirement is important because if state-only provisions are not appropriately designated, they may conflict with or undermine federally enforceable provisions that should otherwise apply.

This concern is particularly relevant in the case of flexible permits. Flexible permits issued by TCEQ provide sources with an alternative to complying with otherwise-applicable requirements

[13] TCEQ acknowledges as much in its RTC. RTC at 23.

[14] To make matters more complicated, the terms of Flexible Permit No. 1176 are combined with the terms of PSD Permit No. PSDTX782 in a single document, and the authority for each individual permit term is not apparent from the face of the combined permit. *See* 40 C.F.R. § 70.6(a)(1)(i) ("The permit shall specify and reference the origin of and authority for each term or condition, and identify any difference in form as compared to the applicable requirement upon which the term or condition is based."); 30 TAC § 122.142(b)(2) ("Each permit shall also contain the specific terms and conditions for each emission unit regarding the following: . . . the specific regulatory citations in each applicable requirement or state-only requirement identifying the emission limitations and standards"); *see also In the Matter of U.S. Dep't of Energy, Hanford Operations*, Order on Petition No. X-2019-8 at 13 n.17 (February 19, 2020).

of the Texas SIP. *See* 30 TAC § 116.710 (a) ("[A] flexible permit . . . allows for physical or operational changes . . . as an *alternative* to obtaining a new source review permit under §116.110 of this title (relating to Applicability), or *in lieu of* amending an existing permit under §116.116 of this title (relating to Changes to Facilities)." (emphasis added)). Because of this, the incorporation of state-only Flexible Permit No. 1176 into BP Amoco's title V permit renders the title V permit unclear and misleading about the requirements that apply to the facility. Specifically, the permit suggests that the facility may rely on the state-only flexible permit to authorize future modifications instead of following the requirement to obtain an authorization under the relevant SIP-approved rules (*e.g.*, those in Chapter 116, Subchapter B, or in a flexible permit issued under the now SIP-approved Subchapter G).[15] This frustrates a central purpose of the title V program: to "clarify, in a single document, which requirements apply to a source and, thus, . . . enhance compliance with the requirements of the Act."[16]

However, nowhere within the Petition do the Petitioners argue that these issues form a basis for EPA's objection to the Permit.[17] Moreover, BP Amoco's flexible permit was recently renewed and reissued under TCEQ's now-SIP-approved rules. Flexible Permit No. 1176 (reissued on April 6, 2020 and revised on May 29, 2020). In response to issues identified in Claim B, this Order requires TCEQ to revise BP Amoco's title V permit. This will necessarily require TCEQ to update the title V permit to incorporate this newest, SIP-approved version of the flexible permit, replacing the prior, non-SIP-approved version. The EPA expects that this will be sufficient to resolve the issues that EPA has identified, as well as those underlying the Petitioners' request for a compliance schedule. That is, the redress sought by the Petitioners through a compliance schedule—a requirement for the facility to obtain a federally enforceable authorization for projects previously authorized by the state-only flexible permit and to include

[15] This concern persists independent from the recent issuance of a valid SIP-approved flexible permit to BP Amoco. Here, the current version of BP Amoco's title V permit (upon which the Petition is based) incorporates the older state-only flexible permit, which was based on different flexible permitting rules that were *not* SIP-approved. Until the title V permit is updated to replace the state-only flexible permit with a SIP-approved flexible permit, there remains an implication within the title V permit that the source may rely on this prior flexible permit in disregard of the proper SIP-approved mechanisms. This is why, as discussed later in this Order, it is important that TCEQ promptly update the title V permit.

[16] 57 Fed. Reg. 32250, 32251 (July 21, 1992); *see id.* ("The title V permit program will enable the source, States, EPA, and the public to understand better the requirements to which the source is subject, and whether the source is meeting those requirements."); *see also* Conference Report on S. 1630—Clean Air Act Amendments: Speech of Hon. Michael Bilirakis of Florida in the House of Representatives (Oct. 26, 1990), reprinted in 6 Environment and Natural Resources Policy Division of the Congressional Research Service of the Library of Congress, Legislative History of the Clean Air Act Amendments of 1990, at 10767-69 (1998) (explaining that the title V program served three purposes, including "to facilitate enforcement by providing a single reference for all of a major source's operating limits and requirements under the Clean Air Act.")

[17] This is notable because the same Petitioners *did* raise such claims in petitions on other permits, such as the April 11, 2017 petition on Blanchard's Galveston Bay Refinery, to which the EPA will respond separately.

this authorization in the facility's title V permit—will effectively be accomplished by the incorporation of the now SIP-approved flexible permit into the title V permit.[18]

The Petitioners are incorrect to suggest otherwise. *See* Petition at 8 (arguing that issuing a SIP-approved flexible permit would not resolve the Petitioners' concerns because the SIP-approved flexible permit program is only available to authorize construction at minor sources, not major sources like BP Amoco). The Petitioners' arguments on this point conflate the distinction between minor *sources* (and major sources) and minor NSR *programs*. Major sources routinely use minor NSR programs to authorize modifications that do not qualify as "major modifications." Specific to the Texas flexible permits program, the EPA has repeatedly explained: "the Flexible Permit program can be used for both true minor sources and for minor modifications at existing major sources[.]" 79 Fed. Reg. 8368, 8380 (February 12, 2014).[19] Nothing in the EPA's approval of the Texas flexible permits program, nor in the Fifth Circuit's *Flex I* and *Flex II* decisions, indicated that only minor *sources* may take advantage of this minor NSR *program*.[20] Thus, to the extent that the Petitioners' claim is predicated on the notion that SIP-approved flexible permits are unavailable to major sources, it is mistaken.

Claim B: The Petitioners Claim That "The Proposed Permit Fails to Assure Compliance with Emission Limits and Operating Requirements Established by BP's New Source Review Permits."

Within Claim B, the Petitioners assert:

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[18] The EPA appreciates the Petitioner's confusion concerning TCEQ's indication that it would add a term to the BP Amoco Permit requiring the source obtain Subchapter B authorizations for the projects authorized by the flexible permit. Prior to TCEQ's issuance of the RTC, BP Amoco had already withdrawn its application to "de-flex" its permit by obtaining Subchapter B authorizations (the outcome suggested by TCEQ's RTC), and instead had submitted an application to obtain a renewed flexible permit under the now SIP-approved regulations. Although TCEQ's RTC did not acknowledge this change of plans, the result is similar: the facility has now obtained a SIP-approved authorization for projects previously authorized by the state-only flexible permit. Therefore, the Petitioners have, in effect, received the relief they requested.

[19] *See also id.* ("Each of these amendments to the Flexible Permit Program ensures that the program is for minor NSR actions and that for any minor amendments to a major source, the source will retain its major source requirements (i.e., cannot be used to circumvent the major source requirements)."); *id.* at 8378 n.7 ("These sources include minor sources as well as major sources seeking minor modifications to their facilities."). These clear statements came from the preamble to the proposed rule conditionally approving the Texas flexible permits program. Some of the Petitioners subsequently challenged the accompanying final rule, which was upheld by the Fifth Circuit in *Flex II*, which the Petitioners cite.

[20] In addition to the clear statements made in proposing to approve the Texas flexible permits program (quoted in the preceding footnote), the EPA explained in its final conditional approval that "this is a minor NSR *program*." 79 Fed. Reg. 40666, 40668, 40669 (July 14, 2014) (emphasis added). Similarly, the Fifth Circuit's *Flex I* and *Flex II* opinions refer repeatedly to "Minor NSR" and "Major NSR"—referring to the two programs, not necessarily the type of source. *Texas v. EPA*, 690 F.3d 670 passim (5th Cir 2012) (*Flex I*); *Flex II*, 610 Fed. Appx. 409 passim (5th Cir. 2015). Neither decision implies that only minor *sources* may take advantage of the flexible permit minor NSR *program*. Instead, both decisions acknowledge that major sources could use the flexible permit program, albeit not in a way that allowed them to avoid Major NSR for a modification that would otherwise trigger it. *See Flex I*, 690 F.3d at 686 (rejecting concerns that major sources might "avoid Major NSR by exploiting the Flexible Permit Program" because "[m]ajor sources cannot use a flexible permit to avoid Major NSR without violating the law."); *Flex II*, 610 Fed. Appx. at 410 (quoting the preceding passage from *Flex I*). This means that while existing major sources may use a flexible permit to authorize minor modifications, they cannot use a flexible permit to authorize a modification that would otherwise be subject to major NSR. To do so would amount to a violation of the SIP.

> The Proposed Permit is deficient because it fails to establish monitoring, reporting, and recordkeeping requirements that assure ongoing compliance with emission limits in [NSR] permits that it incorporates by reference and because the permit record does not contain a reasoned explanation supporting the Executive Director's determination that monitoring provisions in the Proposed Permit assure compliance with these requirements.

Petition at 10. Before presenting specific claims, the Petitioners provide background on the requirements of title V related to monitoring. The Petitioners assert that title V permits must contain monitoring, recordkeeping, and reporting conditions that assure compliance with all applicable requirements, including emission limits in NSR permits and Permits by Rule (PBR) that are incorporated by reference into a title V permit. *Id.* at 11 (citing 42 U.S.C. § 7661c(a), (c); 40 C.F.R. §§ 70.2, 70.6(a)(3), (c)(1); *In the Matter of Wheelabrator Baltimore, L.P.*, Order on Petition, Permit No. 24-510-01886 at 10 (April 14, 2010) (*Wheelabrator Baltimore Order*)).[21] Moreover, the Petitioners contend that the "rationale for the selected monitoring requirements must be clear and documented in the permit record." *Id.* (citing 40 C.F.R. § 70.7(a)(5); *In the Matter of U.S. Steel, Granite City Works*, Order on Petition No. V-2009-03 at 7–8 (January 31, 2011) (*U.S. Steel I Order*)). The Petitioners acknowledge that TCEQ's Statement of Basis for the Draft Permit states "With the exception of any emission units listed in the Periodic Monitoring or CAM Summaries in the [title V permit], the TCEQ Executive Director has determined that the permit contains sufficient monitoring, testing, recordkeeping, and reporting requirements that assure compliance with the applicable requirements." *Id.* at 11 (quoting Statement of Basis at 56). The Petitioners assert that neither the periodic monitoring or CAM summaries address the requirements at issue in Claim B, and that "the Statement of Basis does not provide a reasoned justification for the Executive Director's determination that existing provisions in BP's NSR permits and PBRs assure compliance with applicable permit limits and operating requirements." *Id.*

Claim B includes multiple distinguishable subclaims that EPA has rearranged to facilitate the Agency's analysis. The EPA's response to Claim B addresses each of the Petitioners' allegations according to the following numbering system (not supplied in the Petition):

[21] The Petitioners also note that TCEQ's now SIP-approved flexible permit rules require that monitoring systems in flexible permits "must accurately determine all emissions of the pollutants in terms of mass per unit of time." *Id.* at 11–12 (quoting 30 TAC § 116.715(d)). It is not clear whether these regulations governed the state-only version of Permit No. 1176 that is incorporated into the current title V permit, and/or whether the Petition claims should be judged against this authority alongside the authorities based in title V (cited in the text accompanying this footnote). However, given that each of the emission limits at issue in Claim B are defined in mass per unit of time, the EPA's analysis of whether the Permit assures compliance with these limits under the title V monitoring authorities will inherently also address this SIP-based authority, to the extent it is applicable.

- Claim B.1 addresses NOx and CO emissions from two combustion units authorized by Permit No. 1176/PSDTX782[23] (Petition pages 13–16, 25–27);
- Claim B.2 addresses VOC and benzene emissions from flares authorized by Permit No. 1176/PSDTX782 (Petition pages 16–18, 27–29);
- Claim B.3 addresses VOC and benzene emissions from storage tanks authorized by Permit No. 1176/PSDTX782 (Petition pages 18–20, 29–30);
- Claim B.4 addresses particulate matter (PM) emissions from cooling towers authorized by Permit No. 1176/PSDTX782 (Petition pages 20–21. 30–32); and
- Claim B.5 addresses monitoring associated with PBRs (Petition pages 21–22, 32–34).

Claim B.1: Monitoring of NOx and CO from combustion units

Petitioners' Claim: The Petitioners claim that the monitoring associated with NOx and CO emissions from two mid-sized combustion units (Units HF-204 and HF-601) is insufficient to assure compliance with multi-unit emission caps established by Permit No. 1176/PSDTX782. Petition at 13. Specifically, the Petitioners note that Permit No. 1176/PSDTX782 establishes the following limits on emissions from these two units (along with seven others): 30 lbs/hr NOx, 158.54 TPY NOx; 86.01 lbs/hr CO; 388.54 TPY CO. *Id.* The Petitioners further state that the permit gives BP a choice to calculate NOx and CO emissions from Units HF-204 and HF-601 "using stack test data, if available, vendor guarantee emission factors, or AP-42 emission factors." *Id.* (citing Permit No. 1176/PSDTX782, Special Conditions 7 and 9). The Petitioners assert that all three of the potential monitoring options are objectionable because they do not assure compliance with the relevant emission caps and because they do not reliably determine emissions in mass per unit of time. *Id.* at 13–14.

First, regarding stack testing, the Petitioners claim that the Permit does not require any periodic stack testing of NOx and CO from units HF-204 and HF-601. *Id.* at 14. Instead, the Petitioners assert that Permit No. 1176/PSDTX782 only required BP Amoco to conduct a single stack test prior to February 28, 2003. *Id.* (citing Permit No. 1176/PSDTX782, Special Condition 15). The Petitioners contend: "It is well-established that a single stack-test is not sufficient to assure ongoing compliance with emission limits over the operational life of an emission unit." *Id.* (citing *the Matter of Luke Paper*, Order on Petition, Permit No. 24-001-00011 at 5–6 (October 18, 2010)).

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[23] The Petition challenges the terms of the November 13, 2013 version of Flexible Permit No. 1176, as incorporated into the current title V permit. As an initial matter, it is unclear whether each of the permit terms cited by the Petitioners within Claims B.1, B.2, B.3, and B.4 are associated with state-only Flexible Permit No. 1176 (as the Petitioners suggest) or federally enforceable PSD Permit No. PSDTX782. As noted previously, *supra* note 14, these terms are contained in a combined document (Permit No. 1176/PSDTX782) that includes conditions derived from both permits, but which does not identify the authority for each condition. *See* 40 C.F.R. § 70.6(a)(1)(i). To the extent that these conditions were exclusively derived from a state-only regulation that was not SIP-approved (*i.e.*, the pre-2014 Texas flexible permits program), and had they been designated as not federally enforceable, they would not be properly subject to review through the title V petition process. *See* 40 C.F.R. § 70.6(b)(2) ("Terms and conditions so designated are not subject to the requirements of §§ 70.7, 70.8, or of this part . . . ."). However, because they were not so designated, and given that they may have been derived from TCEQ's authority to issue and revise PSD permits, the EPA is responding to Claims B.1, B.2, B.3, and B.4. This will cease to be an issue once TCEQ incorporates the May 29, 2020 version of Flexible Permit No. 1176 into the title V permit, as this permit was issued under EPA-approved SIP regulations. Claim B.5 does not concern Flexible Permit No. 1176, and so the EPA's response to Claim B.5 is not impacted by these flexible permitting issues.

Second, regarding vendor guarantees, the Petitioners assert that the permit record contains no information supporting the use of vendor guarantees. *Id.* The Petitioners claim that the Permit does not identify any specific guaranteed emission rate, and assert: "Where a Title V permit allows an operator to use an emission factor to determine compliance with an applicable limit, the relevant emission factor must be listed in the permit." *Id.* at 14–15 (citing *In the Matter of U.S. Steel, Granite City Works*, Order on Petition No. V-2011-2, at 9–12 (December 3, 2012) (*U.S. Steel II Order*)). Moreover, the Petitioners claim that the Permit does not identify the operational ranges the source must maintain for the guarantee to apply. *Id.* at 15. Accordingly, the Petitioners assert that the permit record does not demonstrate that vendor guarantees are a reliable indicator of emissions across all possible operating scenarios. *Id.*

Third, regarding the use of AP-42, the Petitioners claim that, according to the EPA, AP-42 emission factors should only be used as a "last resort" to determine compliance with emission limits. *Id.* at 15. (citing EPA, AP-42). The Petitioners assert that although AP-42 factors might be appropriately used to determine compliance with unit-specific requirements, they should not be used to demonstrate compliance with a multi-unit emissions cap like those relevant to these combustion units. *Id.* at 16. In any case, the Petitioners assert that the permit record contains no justification for why AP-42 emission factors would reliably predict actual emissions from Units HF-205 and HF-601, and that the Permit contains no requirements that would assure that BP Amoco's units would be operated consistent with the conditions upon which the relevant emission factors were based. *Id.*

Additionally, the Petitioners assert that none of the three monitoring options require BP Amoco to monitor fuel temperature and pressure, nor does the permit record explain why it is not necessary to do so. *Id.* The Petitioners claim that an indirect monitoring protocol at a different BP facility, which similarly did not account for fuel temperature and pressure, under-predicted actual emissions of combustion units by 20 percent. *Id.* The Petitioners assert that TCEQ failed to respond to comments raising this issue. *Id.* at 27 (citing *Wheelabrator Baltimore Order* at 4–8).

The Petitioners address the RTC that TCEQ did provide,[23] in which TCEQ stated:

> [TCEQ] disagrees that these conditions do not provide an adequate assurance of compliance with emission limits from these sources. CEM, stack testing, or emission calculations are accepted protocols for determining compliance with emission limits. [TCEQ] disagrees that annual stack testing should be required of BP to establish source specific emission factors. AP-42 emission factors are conservative in nature and often overestimate emissions. The rationale for the

[23] Before addressing TCEQ's RTC related to Claim B.1, the Petitioners discuss TCEQ's more general remarks that apply to all the flexible permit monitoring claims (i.e., Claims B.1, B.2, B.3, and B.4). Specifically, to the extent that TCEQ relied on monitoring in unit-specific BACT limits or on unit-specific elements of a source's customized control plan, the Petitioners assert that these requirements cannot assure compliance with the multi-unit flexible emission caps because the permit does not establish any unit-specific BACT limits on the units at issue here, and because the customized control plan is not incorporated into the title V permit. *See id.* at 23–24. Additionally, the Petitioners assert that flexible permits must include heightened monitoring compared to typical NSR permits. *Id.* at 24 (citing 30 TAC § 116.715(c)(5)(B), (d)).

> emission factors and emission calculations is included in the application representations that were made during the NSR permit action that authorized these terms and conditions.

RTC at 11. The Petitioners make two points in response. First, the "Petitioners do not disagree that stack testing and emission calculations are often components of a well-designed monitoring protocol," but "disagree that a single stack test by itself or vendor guarantee or AP-42 emission factors without additional parametric monitoring are sufficient to assure compliance with applicable emission caps," for the reasons previously discussed. *Id.* at 26.

Second, the Petitioners assert that TCEQ's "statement that information supporting the applicable monitoring protocol is available in BP's Flexible Permit applications is not helpful." *Id.* As the Petitioners explain, BP Amoco's flexible permit has been revised many times since it was issued. *Id.* (citing Petition Ex. 8). The Petitioners assert:

> It is not reasonable to expect Petitioners to obtain copies of every application BP has submitted related to its Flexible Permit, read them all, and then determine which representation related to source monitoring are still relevant and support the sufficiency of the monitoring methods listed in BP's Flexible Permit. Instead, the permit record for this project must provide a reasoned justification for the Executive Director's determination that monitoring methods in the Proposed Permit assure compliance with all applicable requirements. Because the record does not contain this information, the Proposed Permit is deficient and the Administrator must object to it.

Id.

EPA's Response: For the following reasons, the EPA grants the Petitioners' request for an objection on this claim.

BP Amoco's title V permit incorporates by reference the entirety of Permit No. 1176/PSDTX782, as issued on November 13, 2013, and also appends this permit to the end of the title V permit document. Final Permit at 12 (Special Condition 20), 224. Special Condition 7 of Permit No. 1176/PSDTX782, as incorporated into the title V permit, reads:

> Available stack test data may be used to calculate NOx emissions from those combustion sources less than 100 MMBtu/hr and not equipped with a CEM. If neither continuous emissions monitoring system (CEMS) nor stack test data is available, then vendor guarantees may be used. The AP-42 emission factors may be used for the calculations if no other data is available.

This same condition contains an identical provision for CO from these units.[24] Additionally, Special Condition 15 of Permit No. 1176/PSDTX782 states:

[24] Special Condition 9, also cited by the Petitioners, concerns CEMS for larger units (≥100 MMBtu/yr).

> The holder of this permit shall perform stack sampling and other testing as required by February 28, 2003, to establish the actual pattern and quantities of NOx and CO being emitted into the atmosphere from the combustion units associated with this permit that are greater than 40 MMBtu/hr, less than 100 MMBtu/hr, do not have a CEMS, and have not been stack tested within five years of the date of this permit. This will be a one-time stack test to establish emission factors for sources that are not utilizing a CEM.

The EPA agrees that the 2013 version of Permit No. 1176/PSDTX782 (*i.e.*, the version currently incorporated into the title V permit) is not clear about which of the available monitoring options BP Amoco must follow for the units at issue in this claim. However, if Special Conditions 7 and 15 are read together, it does seem clear that, at minimum, BP Amoco is required to calculate emissions using emission factors derived from an initial stack test.[25] Accordingly, the Petitioners' concerns regarding the use of vendor guarantees or AP-42 emission factors do not appear particularly relevant to this claim. However, the Petitioners' concerns related to the sufficiency of stack testing are still relevant, as is their overarching claim that the permit record does not justify the sufficiency of the monitoring included in the Permit. Not only are they relevant, but these portions of the Petitioners' claims are persuasive and demonstrate that the current title V permit does not contain sufficient monitoring to assure compliance with applicable emission limits.

Considering the terms currently incorporated into the facility's title V permit (*i.e.*, those contained in the 2013 version of Permit No. 1176/PSDTX782) the relevant monitoring can be summed up as a one-time stack test completed prior to 2003, with the resulting emission factor used to calculate both short-term and annual emissions. This is problematic for multiple reasons. For one, it does not actually mandate *any* periodic monitoring after the initial stack test, such as additional stack testing or the periodic monitoring of operating parameters indicative of emissions. Moreover, the Permit neither identifies the emission factor nor references where it can be found. *U.S. Steel II Order* at 9–12. Additionally, the Permit does not specify the methodology to be used to calculate emissions, including the time frame of emission calculations or what parameters or variables might go into this calculation. Accordingly, the 2013 version of Permit No. 1176/PSDTX782 and, by extension, the title V permit incorporating it, does not contain periodic monitoring sufficient to assure compliance with the relevant hourly and annual emission limits.

The Petitioners' public comments squarely raised these issues for TCEQ's consideration and response. *See* Petition Ex. 1, EIP Comments at 5–6. In response, TCEQ remarked generally that stack testing and emission calculations are "accepted protocols." However, this response provides no explanation for why the state considers the specific monitoring required by the Permit to be sufficient to assure compliance with the NOx and CO limits at issue. That is, this vague response fails to justify the use of emission factors derived from a nearly two-decade old stack test to predict the units' current emissions (*i.e.*, why periodic stack testing or parametric monitoring is not necessary).

[25] This understanding is confirmed by the 2020 version of Permit No. 1176/PSDTX782, which further specifies that the facility will monitor fuel flow and firing rates and calculate NOx and CO emissions using stack test data.

Instead of providing technical justifications, TCEQ's RTC redirected the public as follows: "The rationale for the emission factors and emission calculations is included in the application representations that were made during the NSR permit action that authorized these terms and conditions." RTC at 11. This cursory reference to an unspecified permit application is not enough to justify the sufficiency of monitoring, nor to adequately respond to significant public comments questioning the same. TCEQ's response leaves the public—and for that matter, the EPA—in the dark about where to look, and what to look for.[26] Moreover, a justification provided by a permittee in a permit application should not substitute for the judgement of the permitting authority (TCEQ) with responsibility for ensuring that a title V permit contains sufficient monitoring to ensure compliance. If TCEQ wishes to adopt and incorporate an applicant's technical justification for specific monitoring into the current title V permit record, it must, at minimum, identify specifically where such a justification is to be found (just as it would be required to do it if wished to incorporate by reference a requirement located elsewhere). See the EPA's response to Claim B.4.

The EPA is not suggesting that TCEQ must go out of its way to explain the technical basis for every condition of every permit it has issued to a source every time it renews a title V permit. However, when the state receives public comments raising legitimate challenges to the sufficiency of a monitoring provision, the EPA expects TCEQ to engage with these comments and explain the basis for its decisions (or specifically identify where any prior justification may be found). Because neither TCEQ's RTC nor any other portion of the permit record clearly explain the basis for TCEQ's conclusion that the monitoring associated with Units HF-204 and HF-601 assures compliance with the relevant NOx and CO limits in Permit No. 1176/PSDTX782, the EPA grants this claim. 40 C.F.R. §§ 70.7(a)(5), 70.8(a)(1)(i), 70.8(c)(3)(ii).

Direction to TCEQ: TCEQ must amend the title V permit and/or permit record to ensure that the title V permit contains sufficient monitoring to assure compliance with the relevant NOx and CO limits in Permit No. 1176/PSDTX782. TCEQ could add additional monitoring requirements directly to BP Amoco's title V permit, or it could add such monitoring requirements to Permit No. 1176/PSDTX782 and then promptly revise the title V permit to incorporate the updated version of Permit No. 1176/PSDTX782. In either case, as discussed further with respect to Claim B.4, the *title V permit* must ultimately contain the necessary monitoring in order to resolve the EPA's objection.

The EPA observes that when TCEQ renewed Permit No. 1176/PSDTX782 in 2020, it included a new attachment (Attachment E) addressing monitoring requirements applicable to the units

[26] As the Petitioners suggest, this is no simple task for a permit like Permit No. 1176/PSDTX782, which has been revised numerous times. Although the 2013 version of this permit includes a date next to some permit terms indicating the last time that a permit term was revised, it is unclear whether the application associated with the initial establishment of the term, or the latest revision, or something in between, might contain the information that TCEQ deems relevant. Moreover, the 2020 version of this permit no longer includes these date references, further obscuring the location of any potentially relevant application representations.

implicated by Claim B.1.[27] Specifically, with respect to both NOx and CO emissions from units HF-204 and HF-601, the latest version of Attachment E now identifies the following monitoring: "Continuously monitor the fuel flow and firing rates," and the following short-term and annual emission rates calculations: "Fuel firing rate and stack test data." Permit No. 1176/PSDTX782, Att. E, page 4 (May 15, 2020). Considering these additions, the monitoring regime for the units at issue now consists of a one-time stack test completed prior to 2003 (used to develop an emission factor), followed by continuous monitoring of fuel flow and firing rates. Notably, this monitoring regime has not yet been incorporated into the title V permit.

If TCEQ determines that this updated monitoring regime is sufficient to assure compliance with the relevant NOx and CO limits on Units HF-204 and HF-601, it must provide (or clearly reference) this justification within the title V permit record when it revises the title V permit to include the newest version of Permit No. 1176/PSDTX782. This justification should address the issues identified in the public comments and in the EPA's response to this claim. As with other changes that TCEQ will make to the Permit and/or permit record, any such decision would be subject to EPA review and the public's opportunity to petition.

Claim B.2: Monitoring of VOC and benzene from flares

Petitioners' Claim: The Petitioners claim that the monitoring associated with VOC and benzene emissions from three steam assisted flares (Units FL-201, FL-401, and FL-351) does not reliably determine emissions in mass per unit of time and is insufficient to assure compliance with multi-unit emission caps established by Permit No. 1176/PSDTX782. Petition at 16–17, 18. Specifically, the Petitioners note that Permit No. 1176/PSDTX782 establishes the following limits on emissions from these three flares (along with various other units): 261.23 lbs/hr VOC, 321.29 TPY VOC; 19.67 lb/hr benzene; 29.71 TPY benzene. *Id.* at 16. The Petitioners assert that the Permit fails to assure compliance with these VOC and benzene emission limits because it allows BP Amoco to assume a 98 percent destruction efficiency for flare VOC[28] emissions but does not contain requirements that ensure this 98 percent destruction efficiency will be achieved. *Id.* at 17 (citing Permit No. 1176/PSDTX782, Special Condition 8).

The Petitioners assert that current operational standards—specifically, the Petitioners mention the presence of a pilot light—do not ensure that the BP Amoco flares will continuously achieve the presumed destruction efficiency. *Id.* For support, the Petitioners cite an EPA study that, according to the Petitioners, found that flares complying with requirements equivalent to those in BP Amoco's permit only achieved an average VOC destruction efficiency of 93 percent. *Id.* at 17–18 (citing Petroleum Refinery Sector Rule: Flare Impact Estimates, EPA-HQ-OAR-2010-0682-0209 at 9 (January 16, 2014)).

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[27] *See* Permit No. 1176/PSDTX782, Source Analysis and Technical Review, Page 6 (April 6, 2020) (describing Attachment E as a "New attachment with Monitoring and Calculation Methods as Represented"). This attachment was further revised in May 2020. *See* Permit No. 1176/PSDTX782, Source Analysis and Technical Review, Page 1 (May 29, 2020) ("HF-601, NOx monitoring: Stack testing should not be represented within the NOx column. Previously performed stack testing data (emission factor), fuel flow, and calculations are used for on-going monitoring.").

[28] Although the Petitioners reference both VOC and benzene emissions within this claim, the relevant monitoring provisions only reference VOC emissions and most portions of the Petition also refer only to VOC emissions.

The Petitioners claim that "additional monitoring requirements" are necessary to address problems that are known to reduce destruction efficiency, like over-steaming, excess aeration, high winds, and flame liftoff. *Id.* at 17. The Petitioners challenge TCEQ's contention that there are no currently available EPA-approved mechanisms for testing or monitoring emissions from a flare, and assert that the "EPA has approved monitoring requirements that ensure that flares meet 98-percent destruction efficiency at all times." *Id.* at 28. The Petitioners refer to requirements in 40 C.F.R. § 63.670, promulgated in the Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards, 80 Fed. Reg. 75178, 75211 (December 1, 2015). Moreover, the Petitioners note inconsistencies in TCEQ's RTC, where TCEQ acknowledged these additional requirements for flares, and suggested that the monitoring requirements in Permit No. 1176/PSDTX782 are consistent with the cited 2015 rules for petroleum refineries. The Petitioners challenge this suggestion and assert that the permit does not require BP Amoco to comply with the combustion zone operating limits (and other operating limits) established in that rule in order to assure 98 percent VOC destruction efficiency. *Id.* at 28–29.

EPA's Response: For the following reasons, the EPA grants the Petitioners' request for an objection on this claim.

The Petitioners have demonstrated that neither the title V permit nor Permit No. 1176/PSDTX782 assures that BP Amoco will achieve the 98 percent destruction efficiency assumption embodied in Special Condition 8 of Permit No. 1176/PSDTX782, and accordingly that the title V permit does not include monitoring to assure compliance with the VOC emission limits that are based on that assumption.

In relevant part, the permit provides: "The VOC destruction efficiency of 98 percent shall be used to calculate VOC emissions" associated with routine flare emissions. Permit No. 1176/PSDTX782, Special Condition 8 (November 13, 2013).[29]

In responding to public comments challenging this destruction efficiency assumption, TCEQ discussed various requirements in the EPA's part 60 General Provisions, 40 C.F.R. § 60.18,[30] which TCEQ determined "to be sufficient to yield reliable data to assure compliance with the terms and conditions of the permit regarding *visible* emissions from flares during normal operations." RTC at 12 (emphasis added). Permit No. 1176/PSDTX782 includes these requirements from the part 60 General Provisions; specifically, requirements to maintain a minimum heating value of the combined waste stream and assist natural gas, to not exceed a maximum tip velocity value, to ensure the continuous presence and monitoring of a flame or pilot flame, and to operate with no visible emissions. *See* Permit No. 1176/PSDTX782, Special Condition 4 (November 13, 2013).[31] Additionally, and as TCEQ explained, this permit requires the installation and operation of a continuous flow monitor and composition analyzer that provides a record of the vent stream flow and composition to the flare. *Id.*, Special Condition 4.D. TCEQ asserted that these requirements "are consistent with the revised refinery sector rule" cited by the Petitioners, and stated: "TCEQ is not aware of any facts that would compel

[29] In the more recent April 6 and May 29, 2020 versions of Permit No. 1176/PSDTX782 (not yet incorporated into the facility's title V permit), this condition was moved to Special Condition 10.

[30] Similar requirements are included in the part 63 General Provisions. *See* 40 C.F.R. § 63.11(b).

[31] This condition is Special Condition 5 in the April 6 and May 29, 2020 versions of Permit No. 1176/PSDTX782.

additional monitoring beyond that which has been consistently required under federal law and in Texas permits over the past several decades, especially in the absence of any EPA- or TCEQ-approved methods for monitoring flare emissions." RTC at 12–13.

The terms of Permit No. 1176/PSDTX782, and TCEQ's response, do not directly address the issues raised by public commenters (and in the Petition) that are known to reduce flare combustion efficiency.[32] This is problematic because certain types of flares at certain types of sources—including the steam-assisted flares at BP Amoco's chemical plant—are susceptible to certain performance problems that reduce VOC destruction efficiency below 98 percent.

The EPA, like TCEQ, historically presumed that the requirements contained in the part 60 and 63 General Provisions for flares (specifically, 40 C.F.R. § 60.18 and 63.11(b)) would be sufficient to assure a 98 percent VOC destruction efficiency. However, as the Petitioners correctly note, the EPA has discovered that this is not universally true, primarily because the General Provisions do not account for certain problems that can reduce combustion efficiency, such as those caused by excess steam or air assistance to the flare. As the EPA has explained for flares at petroleum refineries:

> In general, flares used as [air pollution control devices] were expected to achieve 98-percent HAP destruction efficiencies when designed and operated according to the requirements in the General Provisions. Recent studies on flare performance, however, indicate that these General Provisions requirements are inadequate to ensure proper performance of refinery flares, particularly when assist steam or assist air is used. Over the last decade, flare minimization efforts at petroleum refineries have led to an increasing number of flares operating at well below their design capacity, and while this effort has resulted in reduced flaring of gases at refineries, situations of over-assisting with steam or air have become exacerbated, leading to the degradation of flare combustion efficiency.
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> In 2012, the EPA compiled information and test data collected on flares and summarized its preliminary findings on operating parameters that affect flare combustion efficiency (see technical report, Parameters for Properly Designed and Operated Flares, in Docket ID Number EPA-HQ-OAR-2010-0682). The EPA submitted the report, along with a charge statement and a set of charge questions to an external peer review panel. The panel concurred with the EPA's assessment that three primary factors affect flare performance: (1) The flow of the vent gas to the flare; (2) the amount of assist media (e.g., steam or air) added to the flare; and (3) the combustibility of the vent gas/assist media mixture in the combustion zone (i.e.,

[32] This is despite the fact that public commenters specifically requested: "To the extent that the Executive Director disagrees with the study Commenters [c]ite or EPA's findings regarding flare emissions discussed in the recently proposed refinery NESHAP rule, or believes that these findings are inapplicable to BP's flares, Commenters request that he explain the basis for that determination and *explain how monitoring requirements in the Draft Permit will prevent over steaming* and other factors that are known to reduce flare destruction efficiency." Petition Ex. 1, EIP Comments at 8 (emphasis added).

> the net heating value, lower flammability, and/or combustibles concentration) at the flare tip.
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> The current requirements for flares in the General Provisions specify that the flare vent gas must meet a minimum net heating value of 200 British thermal units per standard cubic foot (Btu/scf) for non-assisted flares and 300 Btu/scf for air- and steam-assisted flares. [The prior refinery regulations] reference these requirements, but neither the General Provisions nor [the prior refinery rules] include specific monitoring requirements to monitor the net heating value of the vent gas. Moreover, recent flare testing results indicate that this parameter alone does not adequately address instances when the flare may be over-assisted since it only considers the gas being combusted in the flare and nothing else (e.g., no assist media). However, many industrial flares use steam or air as an assist medium to protect the design of the flare tip, promote turbulence for the mixing, induce air into the flame and operate with no visible emissions. Using excessive steam or air results in dilution and cooling of flared gases and can lead to operating a flare outside its stable flame envelope, reducing the destruction efficiency of the flare. In extreme cases, over-steaming or excess aeration can actually snuff out a flame and allow regulated material to be released into the atmosphere completely uncombusted. Since approximately 90 percent of all flares at refineries are either steam- or air-assisted, it is critical that we ensure the assist media be accounted for in some form or fashion. Recent flare test data have shown that the best way to account for situations of over-assisting is to consider the properties of the mixture of all gases at the flare tip in the combustion zone when evaluating the ability to combust efficiently. As discussed in the introduction to this section, the external peer review panel concurred with our assessment that the combustion zone properties at the flare tip are critical parameters to know in determining whether a flare will achieve good combustion. The General Provisions, however, solely rely on the net heating value of the flare vent gas.

79 Fed. Reg. 36879, 36905, 36907 (August 29, 2014).

Notably, much of the early awareness of this issue came from research conducted by TCEQ. As the state has explained:

> In the fall of 2010, TCEQ funded a research project on flare destruction and removal efficiency (DRE) at a flare-test facility. The results demonstrated that air-assisted and steam-assisted flares must operate within a very limited range of assist rates to achieve the assumed DRE of 98 percent or greater. This project also demonstrated that operating an assisted flare in compliance with 40 CFR 60.18 does not ensure that the flare will achieve 98 percent DRE. Flare assist rates and other operating information must be reviewed and assessed to determine whether a flare may be operating at assist ranges that do not achieve the 98 percent DRE. When operating in a low-flow routine condition, a dual-service flare can easily be over-

> assisted, resulting in a DRE below the assumed 98 percent. The final report and additional project information are at www.tceq.texas.gov/goto/2010-flare-study.

E.g., TCEQ, 2020 Emissions Inventory Guidelines, RG-360/20 at 135 (January 2021).[33]

Thus, the fact that a permit incorporates requirements from the EPA's General Provisions does not necessarily guarantee that the source achieves a 98 percent VOC destruction efficiency. For certain types of flares and/or vent gases, the General Provisions (combined with the relevant NSPS or NESHAP standard)[34] may be sufficient. However, for others that are susceptible to over-assistance—like the steam-assisted flares at BP Amoco that control vent gases similar in composition to those at refineries—these requirements likely are not sufficient.

Based on information gathered by EPA, TCEQ, and others, the EPA has been systematically evaluating and, where sufficient information exists, updating its regulations on a source category-by-source category basis to include additional requirements to address problems related to over-assistance (among other issues).[35] The EPA first focused its attention on the petroleum refining sector. The EPA promulgated regulations for petroleum refineries (regulated under 40 C.F.R. part 63, subpart CC) designed to assure that steam-and air-assisted flares actually achieve a 98 percent VOC destruction efficiency. These regulations require that flares meet a minimum operating limit of 270 BTU/scf on a 15-minute block period basis. 40 C.F.R. § 63.670(e).[36] Importantly, and unlike prior sector-specific rules and the General Provisions, this heating value reflects the net heating value in the combustion zone (NHVcz) (that is, the flare tip), *after* the addition of any assist gas (steam or air) and supplemental fuel. *See id.* § 63.670(m) (calculation methods for NHVcz). This better accounts for any degradation in combustion efficiency that might be caused by dilution of the BTU value by the assist gas. To support this operational limit, the refinery regulations require, for steam- and air-assisted flares, that "the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of assist air and/or assist steam used with the flare," or certain alternative options. *Id.* § 63.670(i).

The EPA's conclusions were not limited to flares at refineries.[37] The EPA has promulgated similar regulations for flares located in the ethylene production source category (regulated under part 63, subpart YY) as well as certain facilities emitting ethylene oxide or producing olefins or

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[33] Similar or identical conclusions have been included in TCEQ publications dating back to at least 2012. *See* TCEQ, 2011 Emissions Inventory Guidelines, RG-360/11 at A-51 to A-52 (February 2012).

[34] The relevant part 60 and 63 General Provisions provide: "Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices." 40 C.F.R. § 60.18(d); *see id.* § 63.11(b)(1).

[35] The EPA has also engaged in numerous compliance assistance and enforcement activities related to this issue. *See, e.g.*, EPA Office of Enforcement and Compliance Assurance, Enforcement Alert, EPA 325-F-012-002 (August 2012).

[36] The EPA explained in its final rule: "Based on the results of all of our analyses, the EPA is finalizing a single minimum NHVcz operating limit for flares subject to the Petroleum Refinery MACT standards of 270 BTU/scf during any 15-minute period. The agency believes, given the results from the various data analyses conducted, that this operating limit is appropriate, reasonable and will ensure that refinery flares meet 98-percent destruction efficiency at all times when operated in concert with the other suite of requirements refinery flares need to achieve (*e.g.*, flare tip velocity requirements, visible emissions requirements, and continuously lit pilot flame requirements)." 80 Fed. Reg. 75178, 75211 (December 1, 2015).

[37] The EPA's conclusions also do not necessarily extend to all flares used in every industry.

polyolefins (regulated under the Miscellaneous Organic Chemical Manufacturing NESHAP in part 63, subpart FFFF). 40 C.F.R. §§ 63.1103(e)(4), 63.2450(e)(5).[38] The EPA has not yet revised the Hazardous Organic NESHAP (HON)—the relevant standard to which BP Amoco's chemical plant is subject—to address these issues. However, the EPA will likely consider flare VOC destruction efficiency (among other issues) in the Agency's next technology review of the HON.[39]

In the meantime, the EPA has sufficient data concerning steam-assisted flares like those used at BP Amoco's chemical plant to conclude that the Petitioners are correct in asserting that the Permit, as currently written, does not assure that BP Amoco's steam-assisted flares will achieve a 98 percent VOC destruction efficiency. As previously explained, the requirements in the EPA's General Provisions, as reflected in Permit No. 1176/PSDTX782, are not enough to assure a 98 percent VOC destruction efficiency at all steam assisted flares because those requirements do not account for issues related to over-steaming that are known to reduce flare destruction efficiency. To TCEQ's credit, the Permit *does* impose requirements beyond those required by the EPA's General Provisions (and the applicable NSPS and NESHAP subparts)—specifically, requirements for a continuous flow monitor and a composition analyzer of the vent gas heading to the flare. However, TCEQ is incorrect to suggest that "the visible emission monitoring, pilot flame monitoring, composition flow meter, and composition analyzer requirements" are consistent with those imposed in the part 63, subpart CC refinery sector rule in order to ensure 98 percent VOC destruction efficiency. RTC at 13. Notably, Permit No. 1176/PSDTX782 lacks other essential elements of that rule, such as the monitoring of assist steam flow rates (among other things) and the calculation of the net heating value of gas in the combustion zone. 40 C.F.R. § 63.670(i), (m). As previously explained, monitoring of assist steam is critical to accurately calculating the heating values of the gas combusted at the flare tip, in order to ensure that the steam assist is not reducing flare performance (i.e., VOC destruction efficiency). Because the permit contains no such conditions, and because TCEQ has not described how the existing permit terms ensure the flares meet the 98 percent VOC destruction efficiency assumption in light of the issues described in public comments and in this response, the EPA grants the Petition with respect to this issue.

Direction to TCEQ: The EPA directs TCEQ to evaluate—in light of the technical considerations described in the preceding paragraphs and TCEQ's stated position that "operating an assisted flare in compliance with 40 CFR 60.18 does not ensure that the flare will achieve 98 percent DRE"[40]—to what extent additional monitoring is necessary to ensure that BP Amoco's steam-assisted flares achieve a 98 percent VOC destruction efficiency, and to revise the Permit and/or permit record accordingly.

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[38] Although the EPA has extended these requirements to industries beyond petroleum refineries, the EPA has also declined to impose additional requirements on certain types of facilities for which EPA does not have data indicating the same concerns with destruction efficiency. *See* 85 Fed Reg. 49084, 49115–49116 (August 12, 2020) (explaining the EPA's decision not to add similar requirements for certain types of facilities regulated under the MON).
[39] *See* EPA, Office of Inspector General, *EPA Should Conduct New Residual Risk and Technology Reviews for Chloroprene- and Ethylene Oxide-Emitting Source Categories to Protect Human Health*, Report No. 21-P-0129 at 29, 36 (May 6, 2021).
[40] TCEQ, 2020 Emission Inventory Guidelines, RG-360/20 at 135 (January 2021).

Based on experience, the EPA anticipates that, in addition to the provisions already contained within Permit No. 1176/PSDTX782, it will be necessary to monitor the flow and composition of assist steam and any supplemental gases (e.g., natural gas) combusted by the flare, in order to calculate the NHVcz, before presuming that BP Amoco's flares achieve a 98 percent VOC destruction efficiency. To this end, TCEQ should consider adding permit terms mirroring the monitoring and calculation methodologies in the EPA's refinery regulations—specifically, 40 C.F.R. § 63.670(i) and (m).[41] Such a monitoring regime, in conjunction with the existing conditions of Permit No. 1176/PSDTX782, should provide sufficient information to indicate whether the flares are achieving a 98 percent VOC destruction efficiency. To the extent any permit terms require the installation of new monitoring equipment, TCEQ could provide a reasonable lead time before such equipment is operational to allow for installation and calibration.

TCEQ could either add such monitoring requirements directly to BP Amoco's title V permit, or it could add such monitoring requirements to Permit No. 1176/PSDTX782 and then promptly revise the title V permit to incorporate the updated version of Permit No. 1176/PSDTX782.[42] In either case, as discussed further with respect to Claim B.4, the *title V permit* must ultimately contain the necessary monitoring in order to resolve the EPA's objection.

If TCEQ determines that a different approach from the one suggested by the EPA would sufficiently resolve the technical issues identified in the preceding paragraphs, it must provide a justification for this decision within the permit record. As with other changes that TCEQ will make to the Permit and/or permit record, any such decision would be subject to EPA review and the public's opportunity to petition.

Claim B.3: Monitoring of VOC and benzene from tanks

Petitioners' Claim: The Petitioners claim that the monitoring associated with VOC emissions from 17 floating roof storage tanks is insufficient to assure compliance with the multi-unit VOC emission caps established by Permit No. 1176/PSDTX782 (the same emission caps that also apply to flares, as discussed in Claim B.2). Petition at 18. The Petitioners address two permit terms:

First, the Petitioners address Special Condition 6(F), which states:

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[41] Although title V provides permitting authorities like TCEQ with the authority to add monitoring, recordkeeping, and reporting provisions to a title V permit when necessary to assure compliance with existing requirements, 42 U.S.C. § 7661c(c), 40 C.F.R. § 70.6(c), this authority does not necessarily extend to the full suite of operating limits and other requirements relevant to flare performance that the EPA has promulgated via sector-specific rules—*e.g.*, the NHVcz operating limits in § 63.670(e). Accordingly, the EPA is not suggesting that TCEQ would necessarily need to establish all of the operating limits from § 63.670 as independently enforceable operating limits within the title V permit. However, if the relevant monitoring shows that BP Amoco's steam-assisted flares do not comply with the relevant thresholds established by 40 C.F.R. § 63.670, the EPA does not believe it would be appropriate to allow BP Amoco to assume a 98 percent VOC destruction efficiency for purposes of demonstrating compliance with the VOC emission limits established by Permit No. 1176/PSDTX782.

[42] Adding any necessary requirements to a preconstruction permit first may afford TCEQ more flexibility to impose additional operating limits and other conditions (as it deems necessary) that might exceed the scope of its authority to impose additional monitoring under title V. *See supra* note 41.

> For purposes of assuring compliance with VOC emission limitations, the holder of this permit shall monitor monthly tank levels and monthly hours of pumping to establish throughputs for comparison with the total maximum throughput used in the emission cap calculations in the permit application. Maximum hourly pump rate shall be used to calculate short-term emissions in the absence of actual pump rate data. Air Emissions Inventory records including actual emissions for each tank and representative examples of calculation methodology shall be maintained for at least two years. These records shall be made available to representatives of the TCEQ upon request.

Id. (quoting Permit No. 1176/PSDTX782, Special Condition 6(F)). The Petitioners claim this condition is insufficient because the permit doesn not establish maximum throughput limits, and because "monitoring that relies on maximum represented throughputs as a constraint on emissions will under-represent actual emissions in cases where actual throughput exceeds the maximum represented throughput." *Id.* at 19.

Second, the Petitioners address Special Condition 6(H), which states:

> Rolling 12-month emissions for tanks and loading operations shall be calculated consistent with the methodology outlined in: (a) AP-42 "Compilation of Air Pollution Factors, Chapter 12—Storage of Organic Liquids" and (b) the TCEQ publication titled "Technical Guidance Package for Chemical Sources—Storage Tanks."

Id. at 18 (quoting Permit No. 1176/PSDTX782, Special Condition 6(H)). The Petitioners claim this condition is also insufficient to assure compliance with the VOC emission caps, because "the AP-42 emission factors that the permit directs BP to use do not account for site-specific variables such as the age and condition the relevant tanks and operating conditions at the chemical plant." *Id.* at 19. Additionally, Petitioners reference studies identified in public comments that purportedly "demonstrate that AP-42 emission factors may significantly under-predict actual VOC emissions from storage tanks at chemical plants and petroleum refineries" because "leaks and other non-routine operating scenarios like roof landings" regularly occur at sources like BP Amoco, and emissions from these activities are not accounted for by the AP-42 emission factors. *Id.* at 19–20.

The Petitioners characterize as "unsupported" and "conclusory" TCEQ's contention in its RTC that AP-42 is an accepted methodology that often overestimates emissions. *Id.* at 29–30. Accordingly, the Petitioners conclude that the EPA must object to the Permit "because the permit record does not contain a reasoned justification for [TCEQ's] determination that AP-42 emission factors and throughput monitoring required by BP's Flexible Permit assure compliance with applicable emission caps and accurately determine actual VOC and benzene[43] emissions from BP's storage tanks in terms of mass per unit of time." *Id.* at 30.

EPA's Response: For the following reasons, the EPA grants in part the Petitioners' request for an objection on this claim.

[43] Although the Petitioners reference both VOC and benzene emissions within this claim, the relevant monitoring provisions only reference VOC emissions and most portions of the Petition also refer only to VOC emissions.

The Petitioners challenge BP Amoco's tank monitoring regime on two fronts. First, the Petitioners' insist that allowing the facility to rely on maximum hourly pump rate could underestimate short-term emissions if the actual pump rate exceeds the maximum hourly pump rate. Petition at 19.[44] The Petitioners have provided no evidence to demonstrate that it is technically possible for the facility to exceed the "maximum" pump rate, or accordingly that the general strategy of relying on maximum pump rate is inappropriate here. Thus, the Petitioners have not provided a basis for EPA to object to the permit on this issue. However, the EPA observes that Permit No. 1176/PSDTX782 does not identify the maximum pump rate or indicate where it can be located. It is possible that the maximum rate is described in a permit application, but the Permit does not specify which application, or where within that application, this maximum pump rate may be located. See the EPA's response to Claim B.4. Although the Petitioners did not specifically identify this problem, the EPA expects TCEQ to address it when it revises the Permit to address the EPA's objection.

Second, the Petitioners challenge the use of AP-42 to calculate tank emissions, arguing that the AP-42 emission factors referenced by the permit do not account for site-specific operating conditions that commonly occur in the operation of tanks like those at the BP Amoco facility. The EPA does not necessarily agree with all of the Petitioners' arguments concerning AP-42 itself,[45] and generally agrees with TCEQ that the equations contained in AP-42 can be an accepted methodology for calculating tank emissions. However, this is contingent on the appropriate use of site-specific inputs, which the AP-42 equations accommodate.[46] Here, the Petitioners have demonstrated that the method by which the Permit incorporates the AP-42 equations does not fully account for these site-specific operating conditions. Permit No. 1176/PSDTX782 (and, by extension, the title V permit) does not appear to contain any terms requiring BP Amoco to monitor or keep records of the inputs necessary to ensure that the AP-42 equations yield accurate emission estimates, such as the temperature and vapor pressure of the liquids stored in these tanks.[47] Accordingly, the EPA grants this claim to the extent it relates to the use of AP-42 equations to calculate VOC emissions from the storage tanks.

Direction to TCEQ: TCEQ must ensure that the Permit contains monitoring and recordkeeping of the appropriate site-specific operating conditions that are used as inputs, in order to ensure that

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[44] This portion of the claim seems restricted to BP Amoco's compliance with the short-term emission limits, as the permit clearly requires monitoring of actual throughput for purposes of demonstrating compliance with the longer-term limits. Permit No. 1176/PSDTX782, Special Condition 6(F).

[45] For example, contrary to the Petitioners' claim that AP-42 does not account for emissions from "leaks and other non-routine operating scenarios like roof landings," Petition at 19–20, AP-42 does now account for emissions from roof landings. *See* AP-42, Section 7.1.3.3 (June 2020). Moreover, Permit No. 1176/PSDTX782 contains additional provisions specifically pertaining to tank roof landings, which the Petitioners did not address. *See* Permit No. 1176/PSDTX782, Special Condition 25 (November 13, 2013).

[46] *See* EPA Office of Enforcement and Compliance Assurance, Enforcement Alert, EPA 325-N-20-001 at 2–3 (November 2020). Comparative studies using remote measurement methods have shown reasonable agreement between AP-42 and the measured emissions from tanks that are not defective, provided accurate site-specific information is used as an input to these equations.

[47] The EPA observes that TCEQ has included the requirements to keep records of relevant tank parameters in permits issued to other facilities. *E.g.*, Permit No. 18287/PSDTX730M4/PAL7 for the ExxonMobil Baytown Refinery, Special Condition 14(E); *In the Matter of ExxonMobil Baytown Refinery*, Order on Petition No. VI-2016-14 at 25–28 (April 2, 2018) (denying a petition claim challenging such conditions).

the AP-42 equations yield reliable emissions estimates for VOC tank emissions. Additionally, to the extent that either these AP-42 equations or other compliance demonstration methodologies related to tank emissions rely on certain set or assumed values (e.g., the use of maximum pump rates) identified in a permit application, TCEQ must amend the permits to specifically identify the location of such values. See the EPA's response to Claim B.4. TCEQ could either add such monitoring requirements directly to BP Amoco's title V permit, or it could add such monitoring requirements to Permit No. 1176/PSDTX782 and then promptly revise the title V permit to incorporate the updated version of Permit No. 1176/PSDTX782. In either case, as discussed further with respect to Claim B.4, the *title V permit* must ultimately contain the necessary monitoring in order to resolve the EPA's objection. As with other changes that TCEQ will make to the Permit and/or permit record, any such decision would be subject to EPA review and the public's opportunity to petition.

Claim B.4: Monitoring of PM from cooling towers

Petitioners' Claim: The Petitioners claim that the monitoring associated with PM10 emissions from two cooling towers (Units CT-351 and CT-451) is insufficient to assure compliance with emission caps established by Permit No. 1176/PSDTX782. Petition at 20. Specifically, the Petitioners note that Permit No. 1176/PSDTX782 establishes the following limits on emissions from the cooling towers (along with combustion units): 9.06 lbs/hr PM10; 39.68 TPY PM10. *Id.* at 16. The Petitioners contend that the Permit does not specify *any* monitoring or testing requirement to determine PM10 emissions from the two cooling towers. *Id.* at 20. Accordingly, the Petitioners conclude that the Permit does not include monitoring to accurately determine emissions in terms of mass per unit of time and that it fails to assure compliance with these PM10 emission limits. *Id.* at 20–21.

The Petitioners also address TCEQ's RTC, which stated:

> [TCEQ]disagrees that a protocol for PM10 monitoring is not included for BP's cooling towers CT-351 and C-451 in NSR permit 1176/PSDTX782. [Special Condition] 5 states, "The holder of this permit shall keep records maintained on-site to demonstrate compliance with the annual TPY emission limits specified by the flexible permit for the following compounds: NOx, CO, PM, SO2, and VOC.["] The application representations for the cooling towers were made during the NSR permit action.
>
> The applicant has submitted a renewal application for NSR permit 1176 (project 176209). During review of project 176209, [TCEQ] has preliminarily determined that for cooling towers, additional monitoring to demonstrate compliance with particulate matter emission limits for the cooling towers is beneficial. When a minor NSR permit lacks sufficient monitoring for an existing facility, [TCEQ]'s current practice is to insert additional monitoring requirements into the NSR permit at the time the permit is renewed. In this situation [TCEQ] believes a similar approach is appropriate.

RTC at 13–14. The Petitioners contest TCEQ's reference to a "protocol" for monitoring PM emissions, asserting that the requirement to maintain records demonstrating compliance is not itself a monitoring protocol. Petition at 31 (citing *U.S. Steel I Order* at 7–8). Moreover, the Petitioners claim that TCEQ does not describe the protocol or identify any information in the permit record that establishes a monitoring protocol. *Id.* The Petitioners also note that the condition referenced by TCEQ only addresses annual PM10 emissions and does not require a demonstration of compliance with the hourly PM10 emission limits. *Id.*

The Petitioners express appreciation that TCEQ planned to improve the monitoring provision in BP Amoco's flexible permit renewal, but claim that this does not excuse TCEQ from its obligation to assure that the title V permit includes conditions necessary to assure compliance with all applicable requirements. *Id.* at 32 (citing 42 U.S.C. § 7661c(a), (c)).

EPA's Response: For the following reasons, the EPA grants the Petitioners' request for an objection on this claim.

The Petitioners have demonstrated that the current title V permit, which incorporates the 2013 version of Permit No. 1176/PSDTX782, does not contain monitoring sufficient to assure compliance with the relevant PM10 limits on the cooling towers.

It is TCEQ's responsibility, as the title V permitting authority, to ensure that the title V permit "set[s] forth" monitoring sufficient to assure compliance with all applicable requirements. 42 U.S.C. § 7661c(c); *see id.* § 7661c(a); 40 C.F.R. § 70.6(a), (a)(3), (c); 30 TAC 122.142(c).[48] However, the only provision in the 2013 version of Permit No. 1176/PSDTX782 that addresses PM emissions from the cooling towers is Special Condition 13,[49] which requires, in relevant part: "The holder of this permit shall keep records maintained on-site to demonstrate compliance with the annual TPY emission limits specified by the flexible permit for the following compounds: NOx, CO, PM, SO2, and VOC." Permit No. 1176/PSDTX782, Special Condition 13 (November 13, 2013). This could hardly be described as a "monitoring protocol" for PM from the cooling towers, as TCEQ suggests in its RTC. RTC at 13.[50] The open-ended recordkeeping requirement in Special Condition 13 does not specify any particular protocol that BP Amoco is required to

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[48] 42 U.S.C. § 7661c(a) ("Each permit issued under [title V of the CAA] shall *include* . . . such other conditions as are necessary to assure compliance with applicable requirements of this chapter, including the requirements of the applicable implementation plan."), 7661c(c) ("Each permit issued under [title V of the CAA] shall *set forth* . . . monitoring and reporting requirements to assure compliance with the permit terms and conditions."); 40 C.F.R. § 70.6(a) ("Each permit issued under this part shall *include* . . ."), 70.6(a)(3)(i) ("Each permit shall *contain* the following requirements with respect to monitoring: . . . ."); 70.6(c) ("All part 70 permits shall *contain* the following with respect to compliance: . . . testing, monitoring, reporting, and recordkeeping requirements sufficient to assure compliance with the terms and conditions of the permit."); 30 TAC § 122.142(c) ("Each permit shall *contain* periodic monitoring requirements that are sufficient to yield reliable data from the relevant time period that are representative of the emission unit's compliance with the applicable requirement, and testing, monitoring, reporting, or recordkeeping sufficient to assure compliance with the applicable requirement.") (all emphasis added).

[49] TCEQ's RTC refers to Special Condition 5 but quotes a passage from Special Condition 13. Special Condition 5 does specify a monitoring methodology for the two cooling towers at issue, but this only applies to VOC emissions, not PM emissions, and is therefore not relevant to this claim.

[50] Although the requirement to maintain records of relevant parameters may constitute sufficient monitoring in certain cases, any such recordkeeping must be sufficient to assure compliance with the relevant limits. 40 C.F.R. § 70.6(a)(3)(i)(B).

follow, but instead leaves the decision about what recordkeeping will be sufficient entirely to the source's discretion. Because neither this general permit term nor any other permit terms specific to the cooling towers require BP Amoco to follow a particular monitoring or recordkeeping methodology, the title V permit cannot be said to "set forth" monitoring sufficient to assure compliance.[51] Moreover, this permit term contains no assurance that the monitoring or recordkeeping selected by the source will, as a technical and legal matter, be sufficient to ensure compliance. Because the permit does not specify any particular monitoring or recordkeeping requirement, neither the public nor the EPA can ascertain from the permit what monitoring or recordkeeping methodology the source has elected to use, or whether this methodology is sufficient to assure compliance with all applicable requirements. This effectively prevents both the public and the EPA from exercising the participatory and oversight roles provided by the CAA. *See* 42 U.S.C. §§ 7661a(b)(6), 7661d(a), (b); *see also* 40 C.F.R. §§ 70.7(h), 70.8(a), (c), (d).

TCEQ's RTC also indicates: "The application representations for the cooling towers were made during the NSR permit action." RTC at 13. This appears to be a suggestion that, notwithstanding the permit's silence as to the required monitoring of PM from cooling towers, a representation within BP Amoco's permit application may discuss the monitoring the source has elected to perform. Even assuming this were the case (the EPA cannot tell from the permit record provided by TCEQ), it would not suffice to satisfy the statutory mandate that title V permits "set forth . . . monitoring . . . requirements to assure compliance with the permit terms and conditions," 42 U.S.C. § 7661c(c), for the following reasons.

The EPA understands that TCEQ's EPA-approved regulations provide that sources in Texas are bound by representations made in their applications for NSR permits, such that these application representations can become legally enforceable.[52] However, the fact that application representations may be legally enforceable in Texas has little to no bearing on whether these representations are properly "set forth," "included," or "contained" in a title V permit, as required by the Act, the EPA's regulations, and TCEQ's EPA-approved regulations. *E.g.*, 42 U.S.C. § 7661c(c).[53] That is, a source's obligation to independently comply with a requirement to which it is subject—whether it be contained in a NSPS, NESHAP, SIP, court-approved Consent Decree, NSR permit, or NSR permit application representation—does not inherently or automatically result in that requirement being included in a title V permit. For a requirement to be included in a title V permit, the permit must include it.

To be sure, this "setting forth," "including," or "containing" may, in certain circumstances, be accomplished by incorporating requirements like application representations into the title V

[51] As discussed with respect to Claim B.5, there may be circumstances where a more permissive approach to monitoring and recordkeeping is appropriate, such as for insignificant emission units subject to general requirements.
[52] *See* 30 TAC § 116.116(a) ("The following are the conditions upon which a permit, special permit, or special exemption are issued: (1) representations with regard to construction plans and operation procedures in an application for a permit, special permit, or special exemption; and (2) any general and special conditions attached to the permit, special permit, or special exemption itself.").
[53] *See supra* note 48.

permit by reference (or even by incorporating them into a NSR permit that is then incorporated by reference into the title V permit).[54] Incorporation by reference is known as "IBR."

In order for something to be incorporated by reference, one must first *reference* it. As the EPA has explained:

> Information that would be . . . incorporated by reference into the issued permit must first be currently applicable and available to the permitting authority and public. . . . Referenced documents must also be specifically identified. Descriptive information such as the title or number of the document and the date of the document must be included so that there is no ambiguity as to which version of which document is being referenced. Citations, cross references, and incorporations by reference must be detailed enough that the manner in which any referenced material applies to a facility is clear and is not reasonably subject to misinterpretation. Where only a portion of the referenced document applies, applications and permits must specify the relevant section of the document. Any information cited, cross referenced, or incorporated by reference must be accompanied by a description or identification of the current activities, requirements, or equipment for which the information is referenced.

White Paper Number 2 at 37. Additionally, the EPA explained:

> Incorporation by reference in permits may be appropriate and useful under several circumstances. Appropriate use of incorporation by reference in permits includes referencing of test method procedures, inspection and maintenance plans, and calculation methods for determining compliance. One of the key objectives Congress hoped to achieve in creating title V, however, was the issuance of comprehensive permits that clarify how sources must comply with applicable requirements. Permitting authorities should therefore balance the streamlining benefits achieved through use of incorporation by reference with the need to issue comprehensive, unambiguous permits useful to all affected parties, including those engaged in field inspections.

Id. at 38.

IBR is a prominent feature of TCEQ's title V program. When the EPA approved the Texas title V program, the EPA balanced the streamlining benefits of IBR against the value of a more detailed title V permit and approved TCEQ's use of IBR for minor NSR requirements, provided the program was implemented correctly. *See* 66 Fed. Reg. 63318, 63321–32 (December 6, 2001).[55] In its program approval, the EPA indicated that monitoring specified in the *terms and*

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[54] *See generally* White Paper Number 2 for Improved Implementation of The Part 70 Operating Permits Program, 36–41 (March 5, 1996) (*White Paper Number 2*) (explaining how IBR can satisfy the requirements of CAA § 504).
[55] *See also Public Citizen v. EPA*, 343 F.3d 449, 460 (5th Cir. 2003) (upholding the EPA's approval of IBR in Texas; stating "Nothing in the CAA or its regulations prohibits incorporation of applicable requirements by reference. The Title V and Part 70 provisions specify what Title V permits 'shall include' but do not state how the items must be included.").

conditions of a minor NSR permit would be incorporated into the title V permit.[56] The EPA did not suggest that unidentified application representations would be considered to be incorporated by reference into a title V permit. Rather, as far as application representations are concerned, TCEQ's EPA-approved title V regulations expressly require that such representations be identified. *See* 30 TAC § 122.140 ("The only representations in a permit application that become conditions under which a permit holder shall operate are the following: . . . (3) any representation in an application *which is specified in the permit* as being a condition under which the permit holder shall operate." (emphasis added)).

Here, there can be no doubt that BP Amoco's title V permit incorporates by reference Permit No. 1176/PSDTX782 and all the terms and conditions therein.[57] However, it does not follow that all potentially relevant representations from unidentified permit applications underlying various iterations of this NSR permit—some of which may have been superseded by, or conflict with, subsequent permit terms or application representations—are also effectively incorporated by reference into the title V permit. Nothing within the title V permit or Permit No. 1176/PSXTX782 references any application representations related to PM emissions from the cooling towers; application representations are first mentioned in TCEQ's RTC, and there only obliquely. This is not sufficient to satisfy CAA § 504(c) and 40 C.F.R. § 70.6(c)(1). If TCEQ wishes to rely on a source's application representations to satisfy the monitoring requirements of title V, the application representations must be specifically identified in an enforceable permit document.

In the last portion of TCEQ's RTC, the state explained that in the process of separately reviewing the renewal of Flexible Permit No. 1176, it "has preliminarily determined that for cooling towers, additional monitoring to demonstrate compliance with particulate matter emission limits for the cooling towers is beneficial." RTC at 13. Notwithstanding this concession that the monitoring contained in the current NSR permit—and, by extension, the title V permit that incorporates it—"lacks sufficient monitoring," TCEQ declined to revise the terms of the title V permit. *Id.* Instead, TCEQ explained that its "current practice is to insert additional monitoring requirements into the NSR permit at the time the permit is renewed." *Id.* at 14.

TCEQ's general preference to update underlying NSR permits first before incorporating these permits into a source's title V permit is not inherently problematic. For example, if TCEQ determines in the course of issuing, modifying, or renewing a NSR permit that monitoring within that permit needs to be supplemented, it may certainly make any necessary adjustments in that

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[56] *Id.* at 63324 ("[A]ll the title V permits will incorporate the necessary [monitoring, recordkeeping, and reporting] which will assure compliance with the title V permit, including [minor] NSR and PBR requirements. . . . [U]nder the incorporation by reference process, Texas must incorporate all terms and conditions of the [minor] NSR permits and PBR, which would include emission limits, operational and production limits, and monitoring requirements. We therefore believe that the terms and conditions of the [minor] NSR permits so incorporated are fully enforceable under the full approved title V program that we are approving in this action.").

[57] Special Condition 20 of the title V permit states: "Permit holder shall comply with the requirements of New Source Review authorizations issued or claimed by the permit holder for the permitted area, including permits, permits by rule, standard permits, flexible permits, . . . referenced in the New Source Review Authorization References attachment. These requirements: A. Are incorporated by reference into this permit as applicable requirements." Final Permit at 12. Permit No. 1176/PSDTX782 is listed in the New Source Review Authorization References attachment. Final Permit at 224.

NSR permit in the first instance. The source's title V permit would then need to be updated to reflect the new or revised terms of the NSR permit in due course (either within 18 months, or at renewal for permits with a remaining term of less than three years). 42 U.S.C. § 7661a(b)(8); 40 C.F.R. § 70.7(f)(1)(i); 30 TAC § 122.231(a)(1)(C).

However, the EPA disagrees with TCEQ's suggestion that "In this situation [TCEQ] believes a similar approach is appropriate." RTC at 14. When commenters identify deficiencies in a title V permit that TCEQ is proposing to issue, the state cannot acknowledge on one hand that the permit's monitoring needs to be supplemented while refusing to do so until a later time. That is, as the Petitioners correctly note, TCEQ's "current practice" of adding supplemental monitoring first to an underlying permit cannot supplant its obligation to ensure that a title V permit contains sufficient monitoring to assure compliance with all applicable requirements and permit terms *at the time it is issued*. *Sierra Club v. EPA*, 536 F.3d 673 (D.C. Cir. 2008); 42 U.S.C. § 7661c(c); 40 C.F.R. § 70.6(a), (c); 30 TAC 122.142(c). Because BP Amoco's title V permit does not contain monitoring sufficient to assure compliance with the PM limits relevant to cooling towers, the EPA grants the Petition on this claim.

Direction to TCEQ: TCEQ must ensure that the TV permit includes monitoring sufficient to assure compliance with the emission limits relevant to PM from the cooling towers. The EPA appreciates that TCEQ followed through on its commitment to include more specific monitoring of PM from cooling towers in the 2020 version of Permit No. 1176/PSDTX782.[58] When TCEQ incorporates the 2020 version of Permit No. 1176/PSDTX782 into the title V permit, this should resolve the initial issue identified in this particular petition claim—that is, the lack of any such monitoring identified in the 2013 version of Permit No. 1176/PSDTX782. The EPA reserves judgment as to the sufficiency of these conditions. As with other changes that TCEQ will make to the Permit and/or permit record, any such decision would be subject to EPA review and the public's opportunity to petition when TCEQ incorporates the latest version of Permit No. 1176/PSDTX782 into the title V permit.

Claim B.5: Monitoring associated with PBRs

Petitioners' Claim: The Petitioners claim that the title V permit does not assure compliance with applicable PBRs because it does not include specific monitoring for these requirements as required by 42 U.S.C. § 7661c(a) and (c) and 40 C.F.R. § 70.6(a)(3) and (c)(1). Petition at 11, 21–22. In particular, the Petitioners contend that PBR 30 TAC § 106.472 (9/4/2000) authorizes emissions from more than 79 tanks and loading facilities at BP Amoco. *Id.* at 21. The Petitioners assert that this PBR contains nothing more than a list of chemicals and does not contain any specific monitoring. *Id.* The Petitioners claim that when a PBR rule does not contain specific monitoring, the only monitoring, recordkeeping, or reporting that applies is contained in Special Conditions 21 and 22 of the title V permit, which contain a "non-exhaustive menu of options that BP Amoco may pick and choose from at its discretion to demonstrate compliance." *Id.* at 21. The Petitioners contend that Special Conditions 21 and 22 alone do not satisfy the requirement for all title V permits to "contain monitoring, recordkeeping, and reporting conditions that assure compliance with all applicable requirements." *Id.* at 11, 22 (citing *Wheelabrator Baltimore Order* at 10). Moreover, the Petitioners contend that these provisions are so vague that the EPA

[58] Permit No. 1176/PSDTX782, Special Condition 7 (April 6, 2020) (identical in the May 29, 2020 version).

and the public cannot evaluate "whether the monitoring methods BP Amoco actually uses to determine compliance with PBR requirements are consistent with Title V." *Id.* at 22.

EPA's Response: For the following reasons, the EPA grants the Petitioners' request for an objection on this claim.

Special Condition 21 of the BP Amoco title V permit states:

> The permit holder shall comply with the general requirements of 30 TAC Chapter 106, Subchapter A or the general requirements, if any, in effect at the time of the claim of any PBR.

Final Permit at 13.

Special Condition 22 of the BP Amoco title V permit states:

> The permit holder shall maintain records to demonstrate compliance with any emission limitation or standard that is specified in a permit by rule (PBR) or Standard Permit listed in the New Source Review Authorizations attachment. The records shall yield reliable data from the relevant time period that are representative of the emission unit's compliance with the PBR or Standard Permit. These records may include, but are not limited to, production capacity and throughput, hours of operation, safety data sheets (SDS), chemical composition of raw materials, speciation of air contaminant data, engineering calculations, maintenance records, fugitive data, performance tests, capture/control device efficiencies, direct pollutant monitoring (CEMS, COMS, or PEMS), or control device parametric monitoring. These records shall be made readily accessible and available as required by 30 TAC § 122.144. Any monitoring or recordkeeping data indicating noncompliance with the PBR or Standard Permit shall be considered and reported as a deviation according to 30 TAC § 122.145 (Reporting Terms and Conditions).

Id.

The Petitioners have demonstrated that with regard to the monitoring, recordkeeping, and reporting requirements for PBRs, the BP Amoco title V permit does not assure compliance with the CAA, part 70, and Texas's approved title V program. Specifically, the Petitioners have demonstrated that certain PBRs incorporated by reference into the title V permit do not contain any additional PBR-specific monitoring, recordkeeping, and reporting and rely solely on the general requirements in Special Conditions 21 and 22. Further, the Petitioners have demonstrated that the general list of monitoring, recordkeeping, and reporting options under special conditions 21 and 22 may not be adequate for all PBRs. As explained in the EPA's *Motiva Order*,[59] a streamlined approach to monitoring, such as in Special Conditions 21 and 22, can be appropriate for generally applicable requirements for *insignificant* units. *Motiva Order* at 26; *White Paper*

[59] *In the Matter of Motiva Enterprises, LLC Port Arthur Refinery*, Order on Petition No. VI-2016-23 (May 31, 2018).

Number 2 at 32. However, the EPA cannot determine if any PBRs in the title V permit apply only to insignificant units.

It is TCEQ's responsibility, as the title V permitting authority, to ensure that the title V permit "set[s] forth" monitoring sufficient to assure compliance with all applicable requirements. 42 U.S.C. § 7661c(c); *see id.* § 7661c(a); 40 C.F.R. § 70.6(a), (a)(3), (c); 30 TAC 122.142(c).[60] Special Condition 21 incorporates the general requirements for PBRs found in 30 TAC Chapter 106, Subchapter A. These requirements do not specify any monitoring methods for demonstrating compliance with the emission limits and standards set forth in the PBRs or for the general emission limits found in Subchapter A. Likewise, Special Condition 22 does not specify any particular monitoring requirements and instead allows BP Amoco to select the monitoring, recordkeeping, or reporting it will use to assure compliance. Because neither these generic permit terms nor the PBRs themselves require BP Amoco to follow a particular monitoring or recordkeeping methodology, the title V permit cannot be said to "set forth" monitoring sufficient to assure compliance. 42 U.S.C. § 7661c(c). The Petitioners have demonstrated that the generic Special Conditions 21 and 22 also contain no assurance that the monitoring or recordkeeping selected by the source will, as a technical and legal matter, be sufficient to ensure compliance. Because the Permit does not specify any particular monitoring or recordkeeping requirement, neither the public nor the EPA can ascertain from the Permit what monitoring or recordkeeping methodology the source has elected to use, or whether this methodology is sufficient to assure compliance with all applicable requirements. This effectively prevents both the public and the EPA from exercising the participatory and oversight roles provided by the CAA. *See* 42 U.S.C. §§ 7661a(b)(6), 7661d(a), (b); *see also* 40 C.F.R. §§ 70.7(h), 70.8(a), (c), (d). Even if the monitoring, recordkeeping, or reporting is eventually specified in a compliance certification, that does not remedy the fact that the title V permit itself still does not include the monitoring, recordkeeping, or reporting.[61] Therefore, the Petitioners have demonstrated that for PBRs authorizing non-insignificant units, Special Conditions 21 and 22 do not contain adequate monitoring, recordkeeping, and reporting requirements that assure compliance with the requirements in each PBR.

Direction to TCEQ: In responding to this order, TCEQ should specify the monitoring, recordkeeping, and reporting that assures compliance with the requirements of the PBRs that apply to non-insignificant units in the BP Amoco title V permit. If any underlying PBRs contain monitoring, recordkeeping, and reporting, TCEQ should identify those PBRs in the permit record and determine if the monitoring in those PBRs is adequate. On the other hand, if any PBRs do not contain any underlying monitoring, recordkeeping, or reporting, like 30 TAC § 106.472, then TCEQ should specify what monitoring, recordkeeping, or reporting will assure compliance with the requirements of those PBRs and the emission limits in 30 TAC 106.4(a)(1) as they apply to units authorized by those PBRs. If the title V permit, Chapter 116 NSR permits, NSPS, NESHAP, or enforceable representations in an application already contain adequate terms to assure compliance with PBRs, then TCEQ should amend the Permit to identify such terms and explain in the permit record how these other requirements assure compliance with the requirements and emission limits for each PBR that applies to significant units. However, if the

[60] *See supra* note 48.
[61] *See* RTC at 14–15. The requirement that a title V permit contain sufficient monitoring and the requirement that sources submit compliance certifications are independent (albeit related) obligations.

title V permit and all enforceable, properly incorporated documents do not contain monitoring, recordkeeping, and reporting sufficient to assure compliance with the PBR requirements, then TCEQ must add such terms to the Permit.

The EPA notes that TCEQ is planning to specify the monitoring for certain PBRs in a PBR Supplemental Table provided by applicants. *See* Letter from Tonya Baer, Deputy Director of Air, TCEQ, to David Garcia, Director, Air and Radiation Division, Region 6, U.S. EPA, *Permits by Rule Programmatic Changes* at 2 (May 11, 2020) (the May 11, 2020 Baer Letter). Specifically, the EPA understands that TCEQ is now requiring title V applicants to fill out the PBR Supplemental Table, which TCEQ will then incorporate into the title V permit through a general condition in the title V permit. *E.g.*, Colorado Bend I Power Title V Permit No. O2887 at 5, Special Condition 7 (March 11, 2021). However, title V applications can be hundreds of (if not over a thousand) pages long, and a search of the TCEQ online database will usually return multiple title V applications for a specific facility that has had multiple revisions and renewals. Thus, a general statement incorporating the PBR Supplemental Table without providing additional information detailing where the table is located is not specific enough to meet the standards related to IBR described with respect to Claim B.4. In order to satisfy the requirement in title V that the Permit "set forth," "include," or "contain" monitoring to assure compliance with all applicable requirements, a special condition incorporating the PBR Supplemental Table would need to include, at minimum, the date of the application and specific location of the table, for example by providing a page number from the application. Alternatively, a more straightforward approach that would obviate these IBR-related concerns would be for TCEQ to directly include (i.e., attach) this PBR Supplemental Table as an enforceable part of the title V permit itself.

Additionally, although this table requires the applicant to specify monitoring, recordkeeping, and reporting for "claimed (not registered)" PBRs, the table does not appear to address monitoring for registered PBRs. For registered PBRs, the EPA understands that TCEQ intends to start having applicants include monitoring in the registration form.[62] However, TCEQ has not indicated how it will appropriately incorporate that monitoring into an enforceable part of the title V permit. The EPA understands that TCEQ's EPA-approved regulations state: "All representations with regard to construction plans, operating procedures, and maximum emission rates in any certified registration under this section become conditions upon which the facility permitted by rule shall be constructed and operated." 30 TAC § 106.6(b). However, the fact that the PBR regulations state that information in the application will be conditions upon which the facility permitted by rule shall be constructed and operated has little to no bearing on whether those provisions are "included" or "contained" in a title V permit, as required by the Act, the EPA's regulations, and TCEQ's EPA-approved regulations. *E.g.*, 42 U.S.C. § 7661c(c).[63] For a requirement to be included in a title V permit, the permit must include it (or properly incorporate it by reference).

As explained with respect to Claim B.4, IBR is a prominent feature of TCEQ's title V program. When the EPA approved the Texas title V program, the EPA balanced the streamlining benefits

[62] TCEQ has stated that it will require applicants to "[u]pdate PBR application representations with monitoring that is sufficient to demonstrate compliance." May 11, 2020 Baer Letter at 3.
[63] *See supra* note 48.

of IBR against the value of a more detailed title V permit and approved TCEQ's use of IBR for PBRs, provided the program was implemented correctly. *See* 66 Fed. Reg. 63318, 63321–32 (December 6, 2001).[64] In its program approval, the EPA indicated that monitoring specified in the *terms and conditions* of a minor NSR permit could be incorporated into the title V permit.[65] The EPA did not suggest that unidentified application representations for minor NSR permits or PBRs would automatically be considered to be incorporated by reference into a title V permit as adequate monitoring, recordkeeping, and reporting. Rather, as far as application representations are concerned, TCEQ's EPA-approved title V regulations expressly require that such representations be identified in the permit itself. *See* 30 TAC § 122.140 ("The only representations in a permit application that become conditions under which a permit holder shall operate are the following: . . . (3) any representation in an application *which is specified in the permit* as being a condition under which the permit holder shall operate." (emphasis added)).

Therefore, TCEQ should include or identify the monitoring, recordkeeping, and reporting from the application forms for registered PBRs (in addition to the claimed but not registered PBRs). With these changes, and provided the PBR Supplemental Table is either included or sufficiently incorporated by reference into the title V permit, the title V permit should include identifiable monitoring, recordkeeping, and reporting necessary to assure compliance with the emission limits and standards in the PBRs.

To the extent that any PBRs apply solely to insignificant units, TCEQ should make those clarifications in the permit and permit record, as necessary, and evaluate whether the general monitoring conditions are or are not sufficient to assure compliance for these insignificant units.[66] The EPA notes that TCEQ has begun including a list of PBRs that only apply to insignificant units in the statement of basis for title V permits. For example, in the statement of basis of title V Permit No. O3027 for Odfjell Terminal Houston, the TCEQ noted that the following PBRs apply only to insignificant units: 30 TAC §§ 106.102, 106.122, 106.141, 106.143, 106.148, 106.149, 106.161, 106.162, 106.163, 106.229, 106.241, 106.242, 106.243, 106.244, 106.266, 106.301, 106.313, 106.316, 106.317, 106.318, 106.319, 106.331, 106.333, 106.372, 106.391, 106.394, 106.414, 106.415, 106.431, 106.432, 106.451, 106.453, 106.471, 106.531. *See e.g.*, Statement of Basis for Draft Title V Permit for Odfjell Terminal Houston at 7–8 (December 20, 2020). The EPA directs TCEQ to make similar clarifications for the BP Amoco title V permit and then determine if the monitoring, recordkeeping, and reporting in Special Conditions 21 and 22 are sufficient for these insignificant units.

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[64] *See supra* note 55.

[65] *Id.* at 63324 ("[A]ll the title V permits will incorporate the necessary [monitoring, recordkeeping, and reporting] which will assure compliance with the title V permit, including [minor] NSR and PBR requirements. . . . [U]nder the incorporation by reference process, Texas must incorporate all terms and conditions of the [minor] NSR permits and PBR, which would include emission limits, operational and production limits, and monitoring requirements. We therefore believe that the terms and conditions of the [minor] NSR permits so incorporated are fully enforceable under the full approved title V program that we are approving in this action.").

[66] The EPA has explained that if a regular program of monitoring, recordkeeping, and reporting for insignificant units would not significantly enhance the ability of the permit to assure compliance with the applicable requirements, general monitoring requirements or even no monitoring can sometimes satisfy title V and 40 C.F.R. § 70.6(a)(3)(i). *See White Paper Number 2* at 32.

Claim C: The Petitioners Claim That "The Proposed Permit's Defective Method of Incorporating [PBR] Requirements by Reference Fails to Assure Compliance with Applicable Requirements."

Petitioners' Claim: The Petitioners raise multiple issues related to the title V permit's incorporation of requirements established by PBRs. The Petitioners claim:

> Generic emission limits established by claimed PBRs and source-specific emission limits contained in BP's certified PBR registrations are not practicably enforceable because (1) the Proposed Permit fails to provide enough information for readers to determine how the generic limits apply to specific units or unit groups at the Texas City Chemical Plant; (2) the Proposed Permit fails to identify which units authorized by PBR are subject to source-specific certified PBR registration limits; and (3) the Proposed Permit fails to incorporate source-specific limits established under 30 Tex. Admin. Code § 106.6.

Petition at 35.

First, the Petitioners claim that the title V permit is unclear as to how much pollution BP Amoco is authorized to emit for each unit under registered and unregistered PBRs because the title V permit is unclear as to how the emission limits from 30 TAC § 106.4 apply when multiple units are authorized by the same PBR. *Id.* at 38. For support, the Petitioners identify 79 tanks as being authorized by PBR 30 TAC § 106.472 (9/4/2000) and assert that the permit does not identify which units were authorized as part of the same project or as part of different projects. *Id.* The Petitioners state, "If each unit was individually authorized, then the combined VOC emissions from the units allowed under § 106.4 would be 1,975 tons per year (25 tons per year * 79 emission units)." *Id.* at 38–39. Therefore, the Petitioners conclude that because the title V permit "is ambiguous as to whether [the units] are authorized to emit 25 tons per year of VOC, 1,975 tons per year of VOC, or some other amount, the [title V permit] fails sufficiently incorporate PBR requirements by reference and does not assure compliance with applicable requirements." *Id.* at 39. In addition, the Petitioners claim that the issue of unclear emission limits for PBRs is complicated by the fact that many PBRs affect emission units already covered by major and minor source case-by-case NSR permits under 30 TAC § 116. *Id.* The Petitioners also provide other examples of multiple emission units being authorized by other PBRs and 30 TAC § 116 permits. *Id.* at 39–40.

Relatedly, the Petitioners claim that the title V permit does not identify which pollutants listed in 30 TAC § 106.4 BP Amoco is authorized to emit for each unit under claimed PBRs. *Id.* at 40. The Petitioners claim that a PBR may be used to authorize emissions of 250 tons per year (TPY) NO_x, 250 TPY CO, 25 TPY VOC, 25 TPY SO_2, 25 TPY PM, 25 TPY Lead, 25 TPY H_2S, 25 TPY H_2SO_4. *Id.* at 41 (citing 30 TAC § 106.4(a)(1)). The Petitioners assert that if every PBR authorized emissions of all pollutants under 30 TAC § 106.4, it would "completely undermine the integrity of Texas's PSD and NNSR programs" because each "claimed PBR would authorize allowable emission increases exceeding applicable major source and major modification thresholds." *Id.* The Petitioners contend that Texas does not read its rules to authorize all pollutants for each claimed PBR. *Id.* The Petitioners note that TCEQ reads 30 TAC § 106.4 to

only authorize emissions of the pollutants "as applicable" to the particular construction project for which the PBR was claimed. *Id.* (quoting 30 TAC § 106.4(a)(1)). Further, the Petitioners claim that TCEQ limits PBRs such that the "cumulative authorized emissions for each PBR project [(group of units)] must remain below major modification thresholds." *Id.* (citing TCEQ PBR Applicability Checklist, Section 1). While the Petitioners acknowledge these safeguards in the PBR program, the Petitioners claim that the title V permit still does not identify which of the many different pollutants under 30 TAC § 106.4 are authorized for each unit under a claimed PBR. *Id.* Therefore, the Petitioners assert that the title V permit fails to assure compliance because, as written, the permit incorrectly suggests that all pollutants under 30 TAC § 106.4 are authorized for each PBR. *Id.* at 42.

Second, the Petitioners claim that the title V permit does not identify any emission unit or group of units for 10 PBRs listed in the title V permit: 106.227 (9/4/2000), 106.231 (9/4/2000), 106.263 (11/1/2001), 106.373 (3/14/1997), 106.412 (9/4/2000), 106.433 (9/4/2000), 106.452 (9/4/2000), 106.453 (9/4/2000), 106.454 (11/1/2001), and 106.492 (9/4/2000). *Id.* at 42. Therefore, the Petitioners contend that the title V permit is unclear as to how the PBRs apply to emission units at the BP Amoco facility and thereby undermines the enforceability of PBR requirements. *Id.* at 42–43 (citing Objection to Title V Permit No. O2164, Chevron Phillips Chemical Company, Philtex Plant (August 6, 2010) at ¶ 7;[67] *Shell Deer Park Order* at 11–15).

Third, the Petitioners claim that the title V permit does not include registration numbers for registered PBRs and is unclear as to which registered PBRs establish source-specific or certified emission limits. *Id.* at 48.

EPA's Response: For the following reasons, the EPA grants the Petitioners' request for an objection on this claim.

Under title V of the CAA, the EPA's part 70 regulations, and Texas's EPA-approved title V program rules, every title V permit must include all applicable requirements that apply to a source, as well as any permit terms necessary to assure compliance with these requirements. *E.g.*, 42 U.S.C. § 7661c(a).[68] "Applicable requirements," as defined in the EPA's and TCEQ's rules, include the terms and conditions of preconstruction permits issued by TCEQ, including requirements contained in a PBR that is claimed by a source, as well as source-specific emission limits established through certified registrations associated with PBRs. *See* 40 C.F.R. § 70.2; 30 TAC § 122.10(2)(H).

[67] The EPA notes that this August 6, 2010 objection was issued under authority delegated by the Administrator to Region 6 to object during EPA's 45-day review period. The objection letter is available at *https://www.tceq.texas.gov/assets/public/permitting/air/Announcements/epa-chevron-2164.pdf*.

[68] CAA section 504(a) requires the following: "Each permit issued under this subchapter shall include enforceable emission limitations and standards, . . . and such other conditions as are necessary to assure compliance with applicable requirements of this chapter, including the requirements of the applicable implementation plan." *Id.*; *see also* 40 C.F.R. § 70.6(a)(1) ("Each permit issued under this part shall include the following elements: (1) Emissions limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of permit issuance."); *id.* § 70.3(c)(1) ("For major sources, the permitting authority shall include in the permit all applicable requirements for all relevant emissions units in the major source."); 30 TAC 122.142(2)(B)(i) ("Each permit shall also contain specific terms and conditions for each emission unit regarding the following: . . . the specific regulatory citations in each applicable requirement or state-only requirement identifying the emission limitations and standards.").

The CAA requirement to include all applicable requirements in a title V permit can be satisfied using IBR in certain circumstances. *See, e.g.*, *White Paper Number 2* at 40 (explaining how IBR can satisfy the requirements of CAA § 504).[69] When the EPA approved the Texas title V program, the EPA balanced the streamlining benefits of IBR against the value of a more detailed title V permit and approved TCEQ's use of IBR for minor NSR requirements (including PBRs), provided the program was implemented correctly. *See* 66 Fed. Reg. 63318, 63321–32 (December 6, 2001). The EPA stated as a condition of program approval that "PBR are incorporated by reference into the title V permit by identifying . . . the PBR by its section number." *Id.* at 63324. Notably, the EPA and TCEQ also agreed as part of the approval process that "PBRs will be cited to the lowest level of citation necessary to make clear what requirements apply to the facility." *Id.* at 63322 n.4. This agreement is consistent with TCEQ's regulations approved by the EPA. *See* 30 TAC 122.142(2)(B)(i) ("Each permit shall also contain specific terms and conditions for each emission unit regarding the following: . . . the *specific regulatory citations* in each applicable requirement or state-only requirement *identifying the emission limitations and standards*." (emphases added)). This is also consistent with the EPA's longstanding position that materials incorporated by reference must be clearly identified in the permit. *See, e.g.*, *White Paper Number 2* at 37 ("Referenced documents must also be specifically identified.").

With regard to the Petitioners' claim that the title V permit is unclear as to what emission limits apply to the units authorized by PBRs, the Petitioners have demonstrated that neither the title V permit nor the permit record explain what emission limits apply (i.e., how much pollution and which pollutants) to each unit authorized by a PBR. The Petitioners have demonstrated that it is unclear how the public could identify which pollutants a PBR authorizes each unit to emit under 30 TAC § 106.4(a)(1) or which PBRs in the BP Amoco title V permit were certified at lower emissions thresholds under 30 TAC § 106.6. Further, at the time the BP Amoco title V permit was issued, it was unclear as to whether the emission limits under 30 TAC § 106.4(a)(1) apply to each unit or to an entire project (group of units) when multiple units are authorized by the same PBR. *See In the Matter of Motiva, Port Arthur Refinery*, Order on Petition No. VI-2016-23, at 27–32 (May 31, 2018) (*Motiva Order*); *In the Matter of Pasadena Refining System, Pasadena Refinery*, Order on Petition No. VI-2016-20, at 10–15 (May 1, 2018) (*Pasadena Order*). The EPA notes that as a result of EPA orders granting similar claims in the *Motiva* and *Pasadena Orders*, TCEQ has clarified how the emission limits under 106.4(a)(1) apply and has begun including clarifying text in the statement of basis for title V permits as they are renewed. *See* June 13, 2018 Wilson Letter. Specifically, TCEQ has begun to include an explanation to the statement of basis in recent title V permits, including:

> The TCEQ has interpreted the emission limits prescribed in 30 TAC §106.4(a) as both emission thresholds and default emission limits. The emission limits in 30 TAC §106.4(a) are all considered applicable to each facility as a threshold matter to ensure that the owner/operator qualifies for the PBR authorization. Those same emission limits are also the default emission limits if the specific PBR does not further limit emissions or there is no lower, certified emission limit claimed by the owner/operator.

[69] *See supra* note 55.

See, e.g., Statement of Basis for Draft Title V Permit for Odfjell Terminal Houston at 94–97 (December 20, 2020).

With regard to the Petitioners' claim that some PBRs are not associated with any emission units in the title V permit, the Petitioners have demonstrated that neither the Permit nor permit record establish to which emission units the following PBRs apply: 106.227 (9/4/2000), 106.231 (9/4/2000), 106.263 (11/1/2001), 106.373 (3/14/1997), 106.412 (9/4/2000), 106.433 (9/4/2000), 106.452 (9/4/2000), 106.453 (9/4/2000), 106.454 (11/1/2001), and 106.492 (9/4/2000). While the New Source Review Authorization References by Emission Unit table identified emission units for most of the PBRs in the title V permit, neither this table nor any other portion of the permits identified the specific emission units to which the aforementioned PBRs apply.

With regard to the Petitioners' claim that the title V permit does not identify registration numbers associated with registered PBRs and does not identify certain source-specific requirements (e.g., certified emission limits) derived from registered PBRs, the Petitioners have demonstrated that the title V permit does not properly incorporate these applicable requirements. Special Condition 20 of the BP Amoco title V permit indicates the following:

> Permit holder shall comply with the requirements of New Source Review authorizations issued or claimed by the permit holder for the permitted area, including permits, permits by rule, [and other types of permits] . . . referenced in the New Source Review Authorization References attachment. These requirements:
>
> A. Are incorporated by reference into this permit as applicable requirements
>
> . . . .

Thus, the title V permit clearly incorporates those NSR authorizations, including PBRs, that are referenced in the New Source Review Authorization References attachment. In the title V permit, the New Source Review Authorization References table and the New Source Review Authorization References by Emissions Unit table (both part of the aforementioned attachment) include references to PBRs by citing various PBR rule numbers and the effective date of each PBR rule. Therefore, it is clear that the requirements contained within the PBR rules cited in these two tables are incorporated by reference into the title V permit.

However, the title V permit does not appear to incorporate other requirements associated with PBR authorizations that are not directly referenced in the New Source Review Authorization References attachment or elsewhere in the title V permit. For example, as the Petitioners point out, the New Source Review Authorization References attachment contains no reference to registered PBRs that contain requirements (including certified source-specific emission limits) that differ from those contained in the PBR rules that the title V permit does directly reference.[70] Although the registered PBRs containing source-specific emission limits are available online,

[70] This is problematic given that, by their nature, the certified source-specific emission limits contained in registered PBRs are necessarily different than the limits contained in the PBR rules with which they are associated. *See* 40 C.F.R. § 70.6(a)(1)(i) ("The permit shall specify and reference the origin of and authority for each term or condition, and identify any difference in form as compared to the applicable requirement upon which the term or condition is based.").

that does not resolve the question of whether the title V permit itself currently includes or incorporates these requirements.

In sum, because the permit contains no direct reference to certain source-specific requirements (e.g., certified emission limits) derived from registered PBRs, it is not clear that the Permit currently includes or incorporates all requirements that are applicable to the facility, as required by the CAA, the EPA's regulations, TCEQ's regulations, the agreements underlying the EPA's approval of IBR in Texas, and the EPA's longstanding position concerning IBR. Therefore, the EPA is granting the Petition with respect to this claim. As discussed further in the following paragraphs, however, the EPA believes that this issue can, and most likely will, be resolved expeditiously by a straightforward solution that the Agency understands TCEQ to be in the process of implementing.

Direction to TCEQ: As explained with respect to Claim B.5, the EPA understands that TCEQ has begun a process to clarify which PBRs only apply to insignificant units at all facilities as their title V permits are renewed. *See e.g.,* Statement of Basis for Draft Title V Permit for Odfjell Terminal Houston at 7–8 (December 20, 2020). To the extent any PBRs in the BP Amoco title V permit apply to insignificant units, TCEQ should make those clarifications in the Permit and permit record, as necessary. If TCEQ makes those changes, the title V permit would likely contain sufficient information on these PBRs to satisfy the requirements of the CAA and TCEQ's approved program. In *White Paper Number 2*, the EPA explained that Part 70 allowed "considerable discretion to the permitting authority in tailoring the amount and quality of information required" for insignificant units in title V permits. *White Paper Number 2* at 30. The EPA explained that applicable requirements related to insignificant units can be addressed in title V permits with minimal or no reference to any specific emissions unit, activity, or emissions information. *White Paper Number 2* at 4, 31. If TCEQ amends the title V permit or permit record to identify those PBRs that only apply to insignificant units, without including any further information on the emissions or direct reference to applicable insignificant emission units, the EPA anticipates such an approach would be consistent with our guidance and the requirements of title V of the CAA.

For the remaining PBRs that do not apply to insignificant units, as previously explained, the EPA recognizes that TCEQ has also begun including in the statement of basis for permits an explanation of how the emission limits under 30 TAC § 106.4(a)(1) apply to the units authorized by PBRs. *See e.g.,* Statement of Basis for Draft Title V Permit for Odfjell Terminal Houston at 94–97 (December 20, 2020); Letter from Michael Wilson, Director, Air Permits Division, TCEQ, to Jeff Robinson, Director, Air and Radiation Division, Region 6, U.S. EPA, *Executive Director's Response to EPA Objections Regarding Permits by Rule* (June 13, 2018) (the June 13, 2018 Wilson Letter). The EPA directs TCEQ to make analogous clarifications to the statement of basis for the BP Amoco title V permit, as appropriate, which the EPA anticipates will resolve this issue.

In addition, TCEQ must explain to which emission units the 10 PBRs identified in the Petition apply. If TCEQ believes that some or all PBRs identified in the Petition only apply to insignificant units, then TCEQ should provide such explanation in the permit record and include a list of those PBRs in the statement of basis. For the remaining PBRs that do not apply only to

insignificant units, TCEQ could update the title V permit and list these PBRs next to the applicable emission units in the New Source Review Authorization References by Emission Unit table.

Finally, the EPA directs TCEQ to modify the title V permit to incorporate certified PBR registrations in a manner that clearly identifies each registration and the emission unit(s) to which it applies. The most straightforward way to do this would involve a reference to the registration numbers associated with each certified PBR registration. These registration numbers function like permit numbers, as they each identify a specific document that contains the specific requirements that apply to the source, including any certified source-specific emission limits taken per 30 TAC 106.6. Thus, the registration numbers point directly to the specific requirements that are applicable to the source. The registered PBR requirements themselves may be found either online, or in person at the TCEQ file room.[71]

Incorporating certified registration numbers could be accomplished in various ways. The EPA understands that TCEQ intends to require permit applicants to fill out a PBR Supplemental Table, which will include registration numbers for all registered PBRs, in all title V applications submitted after August 1, 2020.[72] Further, TCEQ will include the registration numbers in the New Source Review Authorization References by Emission Unit Table with the unit/group/process ID number to which they apply. The EPA expects that this practice would conform with TCEQ's EPA-approved regulations, 30 TAC 122.142(2)(B)(i), as well as the agreements underpinning the EPA's approval of the IBR of PBRs—namely that "PBRs will be cited to the lowest level of citation necessary to make clear what requirements apply to the facility." 66 Fed. Reg. at 63322 n.4.

V. CONCLUSION

For the reasons set forth in this Order and pursuant to CAA § 505(b)(2) and 40 C.F.R. § 70.8(d), I hereby grant in part and deny in part the Petition as described in this Order.

Dated: JUL 20 2021

Michael S. Regan
Administrator

[71] *See https://www.tceq.texas.gov/permitting/air/nav/air_status_permits.html.*
[72] *See* May 11, 2020 Baer Letter.

Coast Guard Captain of the Port or the designated representative.

(4) Upon being hailed by U.S. Coast Guard patrol personnel by siren, radio, flashing light, or other means, the operator of a vessel shall proceed as directed.

(5) The Coast Guard may be assisted by other federal, state, or local agencies in the enforcement of this section.

Dated: January 2, 2009.

T.H. Farris,

Captain, U.S. Coast Guard, Captain of the Port San Diego.

[FR Doc. E9-849 Filed 1-14-09; 8:45 am]

BILLING CODE 4910-15-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 52

[EPA-HQ-OAR-2003-0064, FRL-8762-8]

RIN 2060-AL75

Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Aggregation and Project Netting

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final action.

SUMMARY: The EPA is taking final action on one part of the September 14, 2006 **Federal Register** proposed rule for the New Source Review (NSR) program. The purpose of the proposed rule was to clarify for sources and permitting authorities three aspects of the NSR program—aggregation, debottlenecking, and project netting—that pertain to how to determine what emissions increases and decreases to consider in determining major NSR applicability for modified sources. This final action addresses only aggregation.

This action retains the current rule text for aggregation and interprets that rule text to mean that sources and permitting authorities should combine emissions when activities are "substantially related." It also adopts a rebuttable presumption that activities at a plant can be presumed not to be substantially related if they occur three or more years apart.

With respect to the other two components of the originally proposed rule, the EPA is taking no action on the proposed rule for project netting and, by way of a separate document published in the "Proposed Rules" section of this **Federal Register**, is withdrawing the proposed provisions for debottlenecking.

DATES: This final rule is effective on February 17, 2009.

FOR FURTHER INFORMATION CONTACT: Mr. David Svendsgaard, Air Quality Policy Division, Office of Air Quality Planning and Standards (C504-03), Environmental Protection Agency, Research Triangle Park, NC 27711, telephone number: (919) 541-2380; fax number: (919) 541-5509, e-mail address: *svendsgaard.dave@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

Entities potentially affected by this action include sources in all industry groups. The majority of sources potentially affected are expected to be in the following groups.

Industry group	SIC [a]	NAICS [b]
Electric Services	491	221111, 221112, 221113, 221119, 221121, 221122.
Petroleum Refining	291	324110.
Industrial Inorganic Chemicals	281	325181, 325120, 325131, 325182, 211112, 325998, 331311, 325188.
Industrial Organic Chemicals	286	325110, 325132, 325192, 325188, 325193, 325120, 325199.
Miscellaneous Chemical Products	289	325520, 325920, 325910, 325182, 325510.
Natural Gas Liquids	132	211112.
Natural Gas Transport	492	486210, 221210.
Pulp and Paper Mills	261	322110, 322121, 322122, 322130.
Paper Mills	262	322121, 322122.
Automobile Manufacturing	371	336111, 336112, 336211, 336992, 336322, 336312, 336330, 336340, 336350, 336399, 336212, 336213.
Pharmaceuticals	283	325411, 325412, 325413, 325414.
Mining	211, 212, 213	21.
Agriculture, Fishing and Hunting	111, 112, 113, 115	11.

[a] Standard Industrial Classification.
[b] North American Industry Classification System.

Entities potentially affected by the subject rule for this proposed action also include state, local, and tribal governments.

B. How is this preamble organized?

The information presented in this preamble is organized as follows:

I. General Information
A. Does this action apply to me?
B. How is this preamble organized?
II. Background
III. Aggregation
A. Overview
B. EPA's Policy on Aggregation
C. Retention of Current Rule Text
D. Environmental Impact
IV. Project Netting
V. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review
B. Paperwork Reduction Act
C. Regulatory Flexibility Analysis
D. Unfunded Mandates Reform Act
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks
H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act
L. Judicial Review
VI. Statutory Authority

II. Background

The reader is referred to 67 FR 80187-88 (December 31, 2002) for an overview of the NSR program of the Clean Air Act (CAA) and to 71 FR 54237 (September 14, 2006) for background on this rulemaking.

R012440

III. Aggregation

A. Overview

1. What is "Aggregation"?

When undergoing a physical or operational change, a source determines major NSR applicability through a two-step analysis that first considers whether the increased emissions from a particular proposed change alone are significant, followed by a calculation of the change's net emissions increase considering all contemporaneous increases and decreases at the source (*i.e.*, source-wide netting calculation) to determine if a major modification has occurred. *See*, for example, 40 CFR 52.21(b)(2)(i). The term "aggregation" comes into play in the first step (Step 1), and describes the process of grouping together multiple, nominally-separate but related, physical changes or changes in the method of operation into one physical or operational change, or "project." The emission increases of the nominally-separate changes are combined for purposes of determining whether a significant emissions increase has occurred from the project. *See*, for example, 40 CFR 52.21(b)(40). In addition, when undertaking multiple nominally-separate changes, the source must consider whether NSR applicability should be determined collectively or whether the emissions from each of these activities should separately undergo a Step 1 analysis.[1]

Neither the CAA nor current EPA rules specifically address the basis upon which to aggregate nominally-separate changes for the purpose of making NSR applicability determinations. Instead, we[2] have developed our aggregation policy over time through statutory and regulatory interpretation and applicability determinations. Our aggregation policy aims to ensure the proper permitting of modifications that involve multiple physical and/or operational changes. Thus, multiple, nominally-separate activities that are sufficiently interrelated should be grouped together and considered a single project for the purpose of Step 1 in the NSR applicability test. When these sorts of activities are evaluated separately, they may circumvent the purpose of the NSR program, which is designed to address emissions from projects that have a significant net emissions increase.

[1] Even if activities are determined to be separate and subject to an individual Step 1 analysis, the emission increases and decreases may still be included together in the netting calculation if the projects occur within a contemporaneous period.

[2] In this notice, the terms "we," "us," and "our" refer to the EPA.

2. This Action

On September 14, 2006 (71 FR 54235), we proposed to revise the NSR regulations in 40 CFR parts 51 and 52 to state that a source must aggregate emissions from nominally-separate changes that are dependent on one another to be technically or economically viable. More specifically, we proposed that if a source or reviewing authority determines that nominally-separate changes are dependent on each other for their technical or economic viability, the source and reviewing authority must consider these activities to be a single project and must aggregate all of the emissions increases to properly evaluate major NSR applicability. In our notice's preamble, we offered definitions for the terms "economic dependence" and "technical dependence," and we discussed example scenarios to describe how the test should work. We took comment on all aspects of the proposed regulatory clarification for NSR Aggregation.

As we described in our 2006 proposal preamble, our aggregation policy has never been spelled out in detail in a single letter or memorandum. We have consistently interpreted the CAA to require the grouping of related activities when determining which emissions changes result from a physical or operational change at a facility. At issue is what constitutes a "project" for purposes of determining NSR applicability under the CAA. Proper characterization of this term is important for regulated entities to understand their permitting obligations.

Over the years, our aggregation policy has evolved in large part from specific, case-by-case after-the-fact inquiries related to the possible circumvention of NSR in existing permits. The letters and memoranda resulting from these inquiries have been, until now, the sole resource for permitting authorities and sources to rely upon in making aggregation decisions. However, the decision to aggregate or disaggregate activities is highly case-dependent, such that letters and memoranda that opine on whether to aggregate a particular set of activities at one facility are not necessarily transferrable to a decision to aggregate a similar set of activities but with a slightly different set of circumstances at another plant. Our 2006 proposal aimed to address concerns about applying our policy in such instances.

This **Federal Register** notice takes final action on the regulations concerning NSR aggregation. More specifically, we are finalizing an interpretation of the existing rule language with respect to our policy on aggregation. This interpretation is intended to describe how to approach aggregation under the existing NSR rules. However, elements of this interpretation were proposed for this first time in this action, and are being finalized as a definitive agency position for the first time in this notice. As such, this interpretation will only apply prospectively. As explained below, we are not adopting the amended regulatory text in 40 CFR parts 51 and 52 that we proposed. Through this notice we retain the current relevant regulatory text for "project" and provide our new interpretation of that text regarding when emissions at a source should be aggregated into a single project for purposes of determining major NSR applicability.

In this preamble, we enumerate several principles of our aggregation policy that apply to the existing rule text. We explain that activities should be aggregated for the purposes of the NSR applicability determination only in cases where there is a substantial relationship among the activities, either from a technical or an economic standpoint. The determination of this relationship is based on the relevant case-specific facts and circumstances; as such, sources and permitting authorities should be careful to not over apply the examples in this final notice to cases with slightly different sets of facts and circumstances. In addition to the discussion of the technical or economic relationship, this notice also reiterates the role of timing in making aggregation decisions and establishes for the first time a rebuttable timing-based presumption that permitting authorities may rely upon to support a determination for nonaggregation.

This notice serves as final agency action with respect to our September 2006 proposed criteria for NSR aggregation. This action should enable the aggregation policy to be applied consistently by both those considering the applicability of NSR to potential modifications and those conducting an after-the-fact inquiry regarding whether or not NSR was circumvented through the failure to aggregate dependent physical or operational changes at a source.

B. EPA's Policy on Aggregation

1. Substantial Relationship

We received many comments on our September 2006 proposed rule for aggregation. Comments from all stakeholder groups raised a variety of concerns about our attempts to define

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terms used in the proposed rule and preamble. We sought comment on how to best define the terms "technical dependence" and "economic dependence." Our intent in proposing to add these terms to our regulations was to frame them in a manner that could be universally applied and reduce the subjective nature of the aggregation test. We also requested comments on specific examples of dependence and independence, and asked for other suggestions for maximizing the clarity with which to articulate these criteria.

Many commenters, representing a variety of stakeholder groups, expressed that our definitions and examples were too prescriptive and would lead to increased confusion as compared to the existing policy being applied. They raised specific concerns that our hypothetical examples would restrict one's ability to handle cases that are similar but that have small nuances, and could lead to aggregating physical or operational changes that are truly independent or disaggregating changes that are truly dependent. Commenters also asserted that determining economic dependence would be highly site- and project-specific, so what may prove to be sufficiently related from an economic standpoint at one plant may not have the same level of interconnection at another plant. For example, one commenter stated "* * * it is virtually impossible to craft a meaningful, easy-to-apply test for economic dependence. EPA's proposed criteria for economic dependence may work in some situations * * * but it will not work in the more common situations, where the processes at a source are at least somewhat interrelated."[3] Commenters also raised similar concerns with our efforts to define technical dependence, but to a lesser degree.

We agree with many of the commenters that the proposed definitions for economic and technical dependence/viability were overly prescriptive, and we also agree that the decision to aggregate activities is highly case-specific and requires consideration of factors that are difficult to fully characterize with a bright-line test. We recognize the challenges to precisely describe these terms, particularly when the definitions must apply to the myriad cases that permitting authorities encounter. We have concluded, upon considering the comments, that the terms "dependence" and "viability," though used by EPA in past guidance memoranda, should not be adopted as regulatory "bright lines" regarding whether to aggregate activities under the NSR program. Although we are not adopting regulatory language, we do note that whether a physical or operational change is dependent on another for its viability is still a relevant factor in assessing whether the changes should be aggregated. Technical or economic dependence may be evidence of a substantial relationship between changes, though projects may also be substantially related where there is not a strict dependence of one on the other.

Activities at a source should be aggregated when they are substantially related. To be "substantially related," there should be an apparent interconnection—either technically or economically—between the physical and/or operational changes, or a complementary relationship whereby a change at a plant may exist and operate independently, however its benefit is significantly reduced without the other activity. Two examples offered in our 2006 proposal at 71 FR 54246 present clear cases of a "substantial relationship" between two physical or operational changes: (1) The installation of burners on a utility boiler and a required modification to the air handling system in order to avoid severe impairment when operating the new burners; and (2) the installation of a process heater to make a new product and the installation of a holding tank necessary to hold the new product after its manufacture.

When there is no technical or economic relationship between activities or where the relationship is not substantial, their emissions need not be aggregated for NSR purposes. For example, in most cases, activities occurring in unrelated portions of a major stationary source (*e.g.*, a plant that makes two separate products and has no equipment shared among the two processing lines) will not be substantially related. The test of a substantial relationship centers around the interrelationship and interdependence of the activities, such that substantially related activities are likely to be jointly planned (*i.e.*, part of the same capital improvement project or engineering study), and occur close in time and at components that are functionally interconnected. We note that these factors are not necessarily determinative of a substantial relationship, but are merely indicators that may suggest that two or more activities are likely to be substantially related and, therefore, candidates for aggregation.

For example, at an automotive assembly facility, the mere fact that the various operations at the plant ultimately produce a car does not necessarily mean that a physical or operational change performed at the facility's boiler house is always "substantially related" to any change at the automotive coating operation. Some changes to an industrial boiler may not be substantially related to a particular change at a coating line, since a boiler often serves many other operations at an automotive plant. For instance, if higher pressure steam is needed to drive a steam pump elsewhere within the plant, the boiler island could be retrofitted with an additional heat exchanger to superheat the steam. Even though the boiler may provide power or may heat the make-up air for the coating line enclosures, an expansion at the coating line would not necessarily have a need for the new higher pressure steam output, would probably not be related to the steam pump, and would not necessarily operate more efficiently because of the higher pressure steam that is required by the steam pump. Absent any evidence demonstrating a substantial relationship between such a retrofit at the boiler and the change at the coating line, a permitting authority need not aggregate emissions from these physical changes. On the other hand, if an automotive facility installs a new, larger gas-fired cure oven to handle the increased throughput from the expanded surface coating operation, then we would expect that a substantial relationship between the oven and the coating line activities would exist and these activities' emissions should be aggregated.

Furthermore, simply because a physical or operational change occurs at the same process unit as a previous change does not automatically establish a substantial relationship. As a commenter noted, "[a]lmost all plant improvements are dependent on another piece of equipment as a technical matter. For instance, a chemical synthesis operation may install a new process dryer or a coater may install a new dryer or oven simply because of processes *already* present at a facility. The decision to install the new dryer or oven, however, is separate because of other factors that could include efficiency or fuel improvements, market factors or demand for a new product or the original group of products, or process refinements."[4] We agree with this commenter that, despite the fact that the changes occur at the same process unit, the dryer installation could be separate from other

[3] Douglas J. Fulle, Oglethorpe Power Corporation, EPA–HQ–OAR–2003–0064–0050.1.

[4] Leslie Sue Ritts, National Environmental Development Association's Clean Air Project, EPA–HQ–OAR–2003–0064–0066.1.

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modifications to the process unit if, as suggested by the comment, there was not a substantial technical or economic relationship among the changes. (As noted above, however, a case-specific inquiry is necessary to confirm this.)

Finally, while examining the technical and economic relationship among activities has always been central to aggregation decisions, we note that a portion of one of our past letters addressing a site-specific scenario may have been applied beyond the specific scenario it discussed. In a memorandum issued in 1993 related to a research facility owned by 3M Company in Maplewood, Minnesota[5] (hereafter "3M-Maplewood memo"), after describing different factors that could be considered in deciding whether the source may have circumvented NSR by not aggregating related research and development activities, we concluded the determination by stating that modifications at plants which are expected to modify regularly in response to consumer and projected production demands or research needs "cannot be presumed independent given the plant's overall basic purpose to support a variety of research and development activities." This portion of the analysis could be taken to posit a presumption that all activities at a facility are related for NSR purposes if they contribute to the plant's basic business purpose. This suggestion that all changes consistent with the basic purpose of the source can and should be aggregated is inconsistent with the policy we are adopting in this notice that aggregation should be based on a substantial technical or economic relationship among the activities. Moreover, we are concerned that it could be interpreted to imply that almost any activity is related to any other activity at that source simply because they are both capital investments and support the company's goal to make a profit. This action explains that this is not our interpretation of the NSR rules, and that a source's "overall basic purpose" is not a sufficient basis for determining that activities should be aggregated.

Thus, we affirm that the decision to aggregate nominally-separate changes hinges on whether they have a substantial relationship, and we acknowledge the case-specific nature of this assessment, as well as the multiple considerations that contribute to the assessment. We understand that this policy stops short of providing the bright line criteria we sought to provide in our proposal, and we acknowledge there will continue to be gray areas that sources and permitting authorities will ultimately have to work through in deciding whether or not to aggregate a set of changes at a facility. Permitting authorities, as they have long done, will continue to exercise their best judgment in determining the technical and economic relationship of activities.

[5] "Applicability of New Source Review Circumvention Guidance to 3M-Maplewood, Minnesota" (U.S. EPA, June 17, 1993).

2. Timing of Activities

a. Closely-Timed Activities

Another aspect of our past aggregation policy that has at times been unclear relates to how activities that are performed close in time to each other should be handled in making an NSR applicability assessment. At times, timing of construction has been used, usually in conjunction with one or more other factors, by some permitting authorities as a basis for aggregating or disaggregating activities for NSR applicability. While the relative timing of two or more activities cannot by itself be used to determine whether they have a technical or economic relationship, it is nevertheless an objective criterion that is simpler to apply than assessing the technical and/or economic interaction of the physical or operational changes. As such, it has some appeal, and may have even been used in some cases, as a surrogate for actually establishing a relationship that serves as a basis to aggregate activities.

We are explaining in this notice that timing, in and of itself, is not determinative in a decision to aggregate activities. We do not believe that timing alone should be a basis for aggregation because it is inconsistent with our policy discussed earlier in this notice that the appropriate basis for aggregation should be a substantial technical and economic relationship. Aggregation based on timing alone could, in some cases, clearly result in aggregation of activities that have no technical or economic relationship whatsoever. There should be no presumption that activities automatically should be aggregated as a result of their proximity in time. Activities that happen to occur simultaneously at different units or large integrated manufacturing facilities do not necessarily have a substantial relationship. Even if they occur over a short period of time, multiple activities should be treated as a single project for NSR purposes only when a substantial technical or economic relationship exists among the changes.

Within certain industries, it may be common practice for certain types of activities to be done separately (though not necessarily at separate times). A company's decision to do a series of activities at the same time—*e.g.*, during a conventional scheduled outage, "turnaround" or "annual shutdown"—should not be viewed as evidence of their technical or economic relatedness. In fact, absent an evaluation of the technical or economic relationship among the activities, the only presumption that should be gleaned from the practice of utilities, refineries, and other types of industry to do many activities during normally scheduled outages is that it is efficient and cost-effective to undertake multiple activities at the same time. Some of these activities will, in fact, be unrelated, but are done simultaneously simply because it is easier to make these changes at a time when the source is not operating. These activities should not be automatically aggregated.

We recognize that there has been some confusion over the aforementioned 3M-Maplewood memo and how it portrays the use of timing in making aggregation decisions. While the 3M-Maplewood memo suggested that activities that are timed within one year or eighteen months of each other may be related, and it advises authorities to scrutinize closely-timed minor source permit applications, it did not suggest that such a scenario should be the sole basis for a decision to aggregate. It simply reaffirmed our view that multiple changes over a short period of time "should be studied" for treatment as one project. Hence, it is consistent with this notice.

A state commenter observed "[i]n certain circumstances timing may be a relevant consideration, together with technical and economic factors, but timing is not a conclusive factor as to whether a series of changes should be aggregated. The staging of a project into multiple smaller construction activities within a short time period may signal that further inquiry into a facility's construction activities is appropriate and under the right circumstances, timing may provide evidence, along with other factors, that a facility has or is attempting to circumvent NSR."[6] We agree with this commenter that knowing the timing between activities is useful solely from a standpoint of directing resources to further scrutinize activities that are timed closer together because these changes are generally more apt to be substantially related as opposed to activities that are separated by larger

[6] Carl Johnson, New York State Department of Environmental Conservation, EPA–HQ–OAR–2003–0064–0035.2.

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time frames. In fact, activities that are substantially related are often so heavily aligned or interconnected that constructing only one of the activities at a time is technically unsound or illogical.[7] Therefore, even though activities that occur simultaneously are not to be presumed "substantially related," it makes sense to look closer at these activities since close timing may be one—but should not be the only—indicator of whether a technical or economic relationship exists and is substantial.

b. Time-Based Presumption for Nonaggregation

In our proposal, we also solicited comment on whether we should change our aggregation approach and include a time-based presumption against aggregation. We specifically solicited comments on whether we should create a presumption in the final rule that changes separated by a certain number of years, *e.g.*, three, four, or five years, are independent and not aggregated for NSR purposes. We also solicited comments on whether we should create a rebuttable or irrebuttable presumption.

Some commenters thought that creating a timing presumption for nonaggregation would be beneficial, if properly bounded, since it would streamline the decision making process and add regulatory certainty. Others felt that it was unwarranted and would lead to incorrect results, particularly if it was made to be irrebuttable. Some commenters stated that if we set a timing upper bound for nonaggregation, we should also establish a timing lower bound for automatic aggregation.

In making aggregation decisions, we acknowledge that the determining factor—*i.e.*, whether the activities are "substantially related"—is not always a straightforward analysis. On the other hand, the passage of time provides a fairly objective indicator of nonrelatedness between physical or operational changes. Specifically, the greater the time period between activities, the less likely that a deliberate decision was made by the source to split an otherwise "significant" activity into two or more smaller, non-major activities. If there is a large timeframe between the construction and operation of the activities, it is reasonable to conclude that they should be treated individually and that the CAA did not expect activities separated by large periods of time to constitute a single event when evaluating NSR applicability and control levels.

We believe that if a previous physical or operational change has operated for a period of three or more years, permitting authorities may presume that a newly constructed change is not substantially related to the earlier change. When activities are undertaken three or more years apart, there is less of a basis that they have a substantial technical or economic relationship because the activities are typically part of entirely different planning and capital funding cycles. The fact that the earlier activities were constructed and operated independently for such a long a period of time tends to support a determination that the latter activities are technically and economically unrelated and independent from the other earlier constructed activities. Even if activities are related, once three years have passed, it is difficult to argue that they are *substantially* related and constitute a single project. We note that the selection of a 3-year timeframe is long enough to ensure a reasonable likelihood that the presumption of independence will be valid, but is short enough to maintain a useful separation between relevant construction cycles, consistent with industry practice. For example, in the case of electric utilities, a commenter explained that companies plan and schedule major turbine outages every four to five years.[8]

Nevertheless, we understand that there may be exceptions to the more typical set of circumstances. Therefore, for our 3-year presumptive timeframe that we are adopting, we are making it rebuttable, such that an alternative decision can be made if conditions warrant and if the changes are, in fact, substantially related. In order to rebut the presumption of nonaggregation, there should be evidence that demonstrates a substantial relationship between the activities. For example, evidence that a company intends to undertake a phased capital improvement project, consisting of enhancements to major plant components scheduled for 2009 and 2013 that have a substantial economic relationship would likely be sufficient to rebut the presumption of nonaggregation.

Although some commenters requested that our presumption for nonaggregation be irrebuttable, we have concerns that making it irrebuttable does not fully recognize the fact that sources often implement significant modifications in a series of phased construction projects over a period of years. Setting an irrebuttable presumption would therefore hamper permitting authorities of the ability to monitor compliance with the rules in these instances. A rebuttable presumption, on the other hand, enables the permitting agencies to retain the authority to ensure that facility owners and operators do not engage in a pattern of development including phasing, staging, and delaying or engaging in incremental construction at a facility which, except for such pattern of development, would otherwise require a permit.

While having a timeframe-based presumption for nonaggregation may appear at odds with the previous section of this notice, in which we reject the use of timing alone in making aggregation decisions, the two positions are consistent because they both stem from the same principle that aggregation is based on a technical or economic relationship. Our primary concern with the use of timing in making aggregation decisions has been the interpretation of the 3M-Maplewood memo that aggregates activities occurring within 12 to 18 months of each other without also determining whether a substantial relationship exists between the activities. Thus, we disagree with the commenters who asserted that an upper bound timeframe for nonaggregation should be coupled with a lower bound presumption for aggregation. Establishing an upper bound for timing, particularly one which can be refuted, serves to define a reasonable threshold for what is considered not to be a substantial relationship. Furthermore, by making the presumption rebuttable, we are assuring that the decision is not based on timing alone but must also consider the technical and economic relationship that could overturn the presumption.

While we are establishing this 3-year rebuttable presumption for nonaggregation, we are setting forth our view that activities separated by less than three years have no presumption. If activities within this time period are presumed aggregated, there could be numerous physical or operational changes across a plant that are aggregated without any substantial relationship among them. We believe that, even without a presumption, permitting authorities will continue to be able to aggregate activities when it determines that there is a substantial technical or economic relationship among them. We believe that establishing this presumption will help to streamline and provide some added certainty to the permit decision-making

[7] At the same time, the construction of some projects that are substantially related may occur at entirely different times, simply because of funding or other reasons which dictates the projects be phased.

[8] Bridgett K. Ellis, Tennessee Valley Authority; EPA–HQ–OAR–2003–0064–0088.1.

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process. This 3-year rebuttable presumption will apply prospectively from the effective date of this notice. At that time, we will begin using this 3-year presumptive timeframe when reviewing activities that postdate the effective date of this notice for aggregation. Furthermore, permitting authorities may also adopt this presumptive timeframe as guidance for their sources.

In applying this presumption, the time period separating physical or operational changes should be calculated based on time of approval (*i.e.*, minor NSR permit issuance). If a permit has not been, or will not be, issued for the physical or operational changes, the time period should be based on when construction commences on the changes.

C. Retention of Current Rule Text

In our 2006 proposal, we proposed to amend our rule definition for "project" to provide that "[p]rojects occurring at the same stationary source that are dependent on each other to be economically or technically viable are considered a single project." As discussed earlier in this notice, we have concluded that the terms "economically viable" and "technically viable," and what is meant to be economically or technically dependent, are difficult to define clearly and should not be adopted as regulatory bright lines. We are, therefore, not promulgating the proposed rule for aggregation,[9] nor are we adopting the descriptions of technical and economic viability and dependence that were set forth in the 2006 proposal preamble. We believe the statements made in this notice better explain the NSR Aggregation policy and enable permitting authorities and sources to better implement the current rule text without revision.

D. Environmental Impact

We have determined that the aggregation policy set forth in this notice will not significantly affect air quality and not interfere with achievement of the purposes of the NSR program. Although this notice aims to add certainty to some aspects of the process for making aggregation decisions, it is very unlikely to change the aggregation outcomes in the vast majority of instances.

For example, while this policy clearly specifies that the basis for aggregation is a substantial technical or economic relationship, our experience is that most prior aggregation and nonaggregation decisions already relied on technical or economic relationships to a large degree even if it was not clearly specified that this should be the basis, and we expect that they would have continued to do so even absent this action. Moreover, even allowing for the possibility that a future aggregation or nonaggregation decision could, absent this notice, theoretically have been expressed as relying upon factors other than the technical or economic interrelationship of activities (*e.g.*, on timing alone, or the plant's overall basic purpose), it is not a given that such an aggregation decision would have been any different if the reviewing authority had instead examined the technical or economic relationship.

Even under the new 3-year rebuttable presumption for nonaggregation, we do not expect a significant difference in outcome compared to how physical or operational changes would have been aggregated without the presumption. We expect that there would be few cases under the prior aggregation policy where activities divided by three years or more would have been aggregated for purposes of NSR unless there was a strong technical or economic linkage between them. This outcome would be identical under this policy, which allows for the 3-year presumption to be rebutted in such cases. Thus, while the presumption can assist permitting authorities by streamlining the process for aggregation decisions, it is not likely to lead to appreciably different outcomes.

Therefore, we conclude that there would be negligible environmental impact associated with this final action on aggregation.

IV. Project Netting

In our September 14, 2006 proposal, we proposed a regulatory change to enable emissions decreases from a project to be included in the calculation of whether a significant emissions increase will result from the project. We refer to this NSR concept as "project netting." [10]

We are not taking action on the proposal rule for project netting at this time. We are still considering whether and how to proceed with the project netting proposal. Until we decide on how to proceed with the 2006 proposal for project netting, there is no change in how the Agency views project netting. Therefore, nothing in the September 2006 proposed amendments on project netting should be taken as establishing any change in the Agency's interpretation of its current rules, nor should any of the statements in the 2006 preamble characterizing our current rules be cited as demonstrating the Agency's interpretation of our current rules.

V. Statutory and Executive Order Reviews

A. Executive Order 12866—Regulatory Planning and Review

This action is not a "significant regulatory action" under the terms of Executive Order (EO) 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under the EO.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. We are not promulgating any new paperwork requirements (*e.g.*, monitoring, reporting, recordkeeping) as part of this proposed action. However, OMB has previously approved the information collection requirements contained in the existing regulations (40 CFR parts 51 and 52) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*, and has assigned OMB control number 2060–0003. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Analysis

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this action on small entities, a "small entity" is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this final action on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. In determining whether a rule has a significant economic impact on a

[9] Proposed at §§ 51.165(a)(1)(x)(B)(*1*); 51.166(b)(51)(i); and 52.21(b)(52)(i).

[10] *See* 71 FR 54248–9 for a more complete description of "project netting."

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substantial number of small entities, the impact of concern is any significant *adverse* economic impact on small entities, since the primary purpose of the regulatory flexibility analyses is to identify and address regulatory alternatives ''which minimize any significant economic impact of the rule on small entities.'' See 5 U.S.C. 603 and 604. Thus, an agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive economic effect on all of the small entities subject to the rule.

A Regulatory Flexibility Act Screening Analysis (RFASA) developed as part of a 1994 draft Regulatory Impact Analysis (RIA) and incorporated into the September 1995 ICR renewal analysis, showed that the changes to the NSR program due to the 1990 CAA Amendments would not have an adverse impact on small entities. This analysis encompassed the entire universe of applicable major sources that were likely to also be small businesses (approximately 50 ''small business'' major sources). Because the administrative burden of the NSR program is the primary source of the NSR program's regulatory costs, the analysis estimated a negligible ''cost to sales'' (regulatory cost divided by the business category mean revenue) ratio for this source group. Currently, and as reported in the current ICR, there is no economic basis for a different conclusion.

We have therefore concluded that this notice will not increase, and will possibly decrease, the regulatory burden for all affected small entities.

D. Unfunded Mandates Reform Act

This action contains no Federal mandates under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538 for state, local, or tribal governments or the private sector. This final action is not expected to increase the burden imposed upon reviewing authorities. In addition, we believe this notice may actually reduce the regulatory burden associated with the major NSR program by streamlining the NSR applicability decisionmaking process for permitting authorities and regulated entities. Therefore, this action is not subject to the requirements of sections 202 and 205 of the UMRA.

This action is also not subject to the requirements of section 203 of the UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. As discussed above, this final rule does not impose any new requirements on small governments.

E. Executive Order 13132—Federalism

Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by state and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.''

This final action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. In addition, we believe this final action will actually reduce the regulatory burden associated with the major NSR program by streamlining the NSR applicability decisionmaking process for permitting authorities and regulated entities. Thus, Executive Order 13132 does not apply to this action.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and state and local governments, EPA specifically solicited comments on the proposed rule from state and local officials.

F. Executive Order 13175—Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). No tribal government currently has an approved tribal implementation plan (TIP) under the CAA to implement the NSR program; therefore the Federal government is currently the NSR reviewing authority in Indian country. Thus, tribal governments should not experience added burden from this final action, nor should their laws be affected with respect to implementation of this action. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045—Protection of Children From Environmental Health Risks and Safety Risks

EPA interprets Executive Order 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it does not establish an environmental standard intended to mitigate health or safety risks.

H. Executive Order 13211—Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, 12(d) (15 U.S.C. 272 note), directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (for example, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This action does not involve technical standards. Therefore, EPA did not consider the use of any voluntary consensus standards.

J. Executive Order 12898—Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629 (Feb. 16, 1994)) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this final action will not have disproportionately high and adverse human health or environmental effects on minority or

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low-income populations because it does not affect the level of protection provided to human health or the environment. This action, in conjunction with other existing programs, would not relax the control measures on sources regulated by the final action and therefore would not cause emissions increases from these sources.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective February 17, 2009.

L. Judicial Review

Under CAA section 307(b), judicial review of this final action is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit on or before March 16, 2009. Under CAA section 307(d)(7)(B), only those objections to the final rule that were raised with specificity during the period of public comment may be raised during judicial review. Moreover, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brough by EPA to enforce those requirements.

VI. Statutory Authority

The statutory authority for this action is provided by sections 307(d)(7)(B), 101, 111, 114, 116, and 301 of the CAA as amended (42 U.S.C. 7401, 7411, 7414, 7416, and 7601). This notice is also subject to section 307(d) of the CAA (42 U.S.C. 7407(d)).

List of Subjects

40 CFR Part 51

Environmental protection, Administrative practice and procedure, Air pollution control, Baseline emissions, Intergovernmental relations, Netting, Aggregation, Major modifications, Reporting and recordkeeping requirements.

40 CFR Part 52

Environmental protection, Administrative practice and procedure, Air pollution control, Baseline emissions, Intergovernmental relations, Netting, Aggregation, Major modifications, Reporting and recordkeeping requirements.

Dated: January 12, 2009.

Stephen L. Johnson,

Administrator.

[FR Doc. E9–815 Filed 1–14–09; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R06–OAR–2007–1153; FRL–8762–4]

Approval and Promulgation of Air Quality Implementation Plans; Arkansas; Emissions Inventory for the Crittenden County Ozone Non-Attainment Area; Emissions Statements

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: The Environmental Protection Agency (EPA) is approving a revision to the Arkansas State Implementation Plan (SIP) to meet the Emissions Inventory and Emissions Statements requirements of the Clean Air Act (CAA) for the Crittenden County ozone nonattainment area. EPA is approving the SIP revision because it satisfies the Emissions Inventory and Emissions Statements requirements for 8-hour ozone nonattainment areas. EPA is approving the revision pursuant to section 110 of the CAA.

DATES: This direct final rule will be effective March 16, 2009 without further notice unless EPA receives adverse comments by February 17, 2009. If adverse comments are received, EPA will publish a timely withdrawal of the direct final rule in the **Federal Register** informing the public that the rule will not take effect.

ADDRESSES: Submit your comments, identified by Docket No. EPA–R06–OAR–2007–1153, by one of the following methods:

- *Federal e-Rulemaking Portal: http://www.regulations.gov.*
- Follow the online instructions for submitting comments.
- *EPA Region 6 ''Contact Us'' Web site: http://epa.gov/region6/r6comact.htm.* Please click on ''6PD (Multimedia)'' and select ''Air'' before submitting comments.
- *E-mail:* Mr. Guy Donaldson at *donaldson.guy@epa.gov.* Please also send a copy by e-mail to the person listed in the **FOR FURTHER INFORMATION CONTACT** section below.
- *Fax:* Mr. Guy Donaldson, Chief, Air Planning Section (6PD–L), at fax number 214–665–7242.
- *Mail:* Mr. Guy Donaldson, Chief, Air Planning Section (6PD–L), Environmental Protection Agency, 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733.
- *Hand or Courier Delivery:* Mr. Guy Donaldson, Chief, Air Planning Section (6PD–L), Environmental Protection Agency, 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733. Such deliveries are accepted only between the hours of 8 a.m. and 4 p.m. weekdays, and not on legal holidays. Special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket No. EPA–R06–OAR–2007–1153. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or e-mail. The *www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *www.regulations.gov* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index,

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

■ 1. The authority citation for part 165 continues to read as follows:

Authority: 33 U.S.C. 1231; 50 U.S.C. 191; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Department of Homeland Security Delegation No. 0170.1.

■ 2. Add § 165.T01–0849 to read as follows:

§ 165.T01–0849 Safety Zone; The Gut, South Bristol, ME.

(a) *Location.* The following area is a safety zone: All waters of The Gut, a waterway between Rutherford Island and Bristol Neck in South Bristol, ME, from surface to bottom, encompassed by a 50-yard radius from the center point of The Gut Bridge at position 43°51.720′ N, 069°33.480′ W (NAD 83).

(b) *Definitions.* As used in this section:

Designated representative means any Coast Guard commissioned, warrant, petty officer, or designated Patrol Commander of the U.S. Coast Guard who has been designated by the Captain of the Port, Sector Northern New England (COTP), to act on his or her behalf. The designated representative may be on an official patrol vessel or may be on shore and will communicate with vessels via VHF–FM radio or loudhailer. In addition, members of the Coast Guard Auxiliary may be present to inform vessel operators of this regulation.

Official patrol vessels means any Coast Guard, Coast Guard Auxiliary, state, or local law enforcement vessels assigned or approved by the COTP to enforce this section.

(c) *Enforcement period.* This rule is effective without actual notice from November 15, 2018 through 11:59 p.m. on March 31, 2019. For the purposes of enforcement, actual notice will be used from 12:01 a.m. on November 8, 2018 through November 15, 2018. The rule will only be enforced during active bedrock removal operations or other instances which may cause a hazard to navigation, or when deemed necessary by the Captain of the Port (COTP), Northern New England.

(d) *Regulations.* When this safety zone is enforced, the following regulations, along with those contained in § 165.23 apply:

(1) No person or vessel may enter or remain in the safety zone described in paragraph (a) of this section unless authorized by the COTP or the COTP's designated representative.

(2) To obtain permission required by this regulation, individuals may reach the COTP or the COTP's designated representative via Channel 16 (VHF–FM) or (207) 767–0303 (Sector Northern New England Command Center).

(3) During periods of enforcement, any person or vessel permitted to enter the safety zone must comply with all lawful orders or directions given to them by the COTP or the COTP's designated representative.

(e) *Penalties.* Those who violate this section are subject to the penalties set forth in 33 U.S.C. 1232.

(f) *Notification.* Coast Guard Sector Northern New England will give notice through the Local Notice to Mariners and Broadcast Notice to Mariners for the purpose of enforcement of temporary safety zone. Coast Guard Sector Northern New England will also notify the public to the greatest extent possible of any period in which the Coast Guard will suspend enforcement of this safety zone.

Dated: November 8, 2018.

B.J. LeFebvre,

Captain, U.S. Coast Guard, Captain of the Port, Sector Northern New England.

[FR Doc. 2018–24809 Filed 11–14–18; 8:45 am]

BILLING CODE 9110–04–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 52

[EPA–HQ–OAR–2003–0064; FRL–9986–47–OAR]

RIN 2060–AP80

Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Aggregation; Reconsideration

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final action; lifting of administrative stay and announcement of effective date.

SUMMARY: In this action, the Environmental Protection Agency (EPA) is concluding the reconsideration of an earlier action that the EPA published on January 15, 2009, titled ''Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Aggregation and Project Netting.'' The 2009 action—hereafter referred to as ''2009 NSR Aggregation Action''—clarified implementation of the New Source Review (NSR) permitting program under the Clean Air Act (CAA or Act) with respect to treating related physical or operational changes as a single ''modification'' for the purpose of determining NSR applicability at a stationary source. On April 15, 2010, the EPA proposed to revoke the 2009 NSR Aggregation Action. After a review of the public comments received on that proposal, the EPA has now decided to not revoke the 2009 NSR Aggregation Action. The EPA is, therefore, retaining the interpretation set forth in the 2009 NSR Aggregation Action, while not adopting any changes to the relevant rule text. At the same time, the EPA is using this present action to clarify the implications of the 2009 NSR Aggregation Action for EPA-approved permitting programs. This action also lifts the administrative stay and announces the effective date of the 2009 NSR Aggregation Action.

DATES: This action is effective on November 15, 2018.

ADDRESSES: The EPA has established a docket for this action, identified by Docket ID No. EPA–HQ–OAR–2003–0064. All documents in the docket are listed in the *http://www.regulations.gov* website. Although listed in the index, some information may not be publicly available, *e.g.*, Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy. Publicly available docket materials are available electronically in *http://www.regulations.gov*.

FOR FURTHER INFORMATION CONTACT: For further general information on this action, contact Mr. Dave Svendsgaard, Office of Air Quality Planning and Standards (OAQPS), Air Quality Policy Division, U.S. EPA, Mail Code 504–03, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711; by telephone at (919) 541–2380; or by email at *svendsgaard.dave@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

Entities potentially affected directly by this action include sources in all industry categories. Entities potentially affected by this action also include state, local and tribal air pollution control agencies (air agencies) responsible for permitting sources pursuant to the NSR program.

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this **Federal Register** document will be posted at *https://www.epa.gov/nsr*.

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C. How is this document organized?

The information presented in this document is organized as follows:

I. General Information
A. Does this action apply to me?
B. Where can I get a copy of this document and other related information?
C. How is this document organized?
II. Background
A. What is New Source Review?
B. What is project aggregation?
C. Regulatory History
III. This Action
A. Overview
B. Retaining the 2009 NSR Aggregation Action
C. Completing the Reconsideration Proceeding
D. Lifting the Administrative Stay; Announcement of Effective Date
IV. Environmental Justice Considerations
V. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
VI. Judicial Review
VII. Statutory Authority

II. Background

A. What is New Source Review?

The NSR program is a preconstruction permitting program that requires certain stationary sources of air pollution to obtain permits prior to beginning construction. The NSR permitting program applies both to new construction and to modifications of existing sources, regardless of whether the source is in an area where the national ambient air quality standards (NAAQS) have been exceeded (nonattainment area) or if the source is in an area where the NAAQS have not been exceeded (attainment or unclassifiable area). New construction and modifications that emit "regulated NSR pollutants" [1] over certain thresholds are subject to major NSR requirements, while smaller emitting sources and modifications may be subject to minor NSR requirements or be excluded from NSR altogether.

Major NSR permits for sources that are located in attainment or unclassifiable areas are referred to as Prevention of Significant Deterioration (PSD) permits. These permits can also cover pollutants for which there are no NAAQS. Major NSR permits for sources located in nonattainment areas and that emit pollutants above the specified thresholds for which the area is in nonattainment are referred to as nonattainment NSR (NNSR) permits. The pollutant(s) at issue and the air quality designation of the area where the facility is located or proposed to be built determine the specific permitting requirements. The CAA requires sources subject to PSD to meet emission limits based on Best Available Control Technology (BACT) as specified by CAA section 165(a)(4), and sources subject to NNSR to meet Lowest Achievable Emissions Rate (LAER) pursuant to CAA section 173(a)(2). Other requirements to obtain a major NSR permit vary depending on whether it is a PSD or NNSR permit.

A new stationary source is subject to major NSR requirements if its potential to emit (PTE) a regulated NSR pollutant exceeds statutory emission thresholds.[2] If it exceeds the applicable threshold, the NSR regulations define it as a "major stationary source." [3] An existing major stationary source triggers major NSR permitting requirements when it undergoes a "major modification," which occurs when a source undertakes a physical change or change in method of operation (*i.e.*, a "project") that would result in (1) a significant emissions increase from the project, and (2) a significant net emissions increase from the source (*i.e.*, a source-wide "netting" analysis that considers creditable emission increases and decreases occurring at the source as a result of other projects over a 5-year contemporaneous period). *See, e.g.*, 40 CFR 52.21(b)(2)(i) and 40 CFR 52.21(b)(52). For this two-step process, the NSR regulations define what emissions rate constitutes "significant" for each NSR pollutant. *See* 40 CFR 51.165(a)(1)(x), 40 CFR 51.166(b)(23), and 40 CFR 52.21(b)(23).

In many cases, these requirements of the major NSR program (or equivalent requirements) are formally adopted by a state or local air agency, and the agency submits a revised state implementation plan (SIP) to the EPA for approval. The EPA's regulations provide for the minimum requirements of these programs. Upon EPA approving the SIP, the air agency becomes the "permitting authority" for major NSR permits for sources within its boundaries. When a state or local air agency is not the permitting authority, either the EPA issues the major NSR permits or a state or local air agency issues the major NSR permits on behalf of the EPA by way of a delegation agreement. For sources located in Indian country, the EPA is currently the only permitting authority for major NSR. Currently, state and local air agencies issue the vast majority of major NSR permits each year.

New sources and modifications that do not require a major NSR permit may instead require a minor NSR permit prior to construction. Minor NSR permits are almost exclusively issued by state and local air agencies, although the EPA issues minor NSR permits in some areas of Indian country. Minor NSR requirements are approved into a SIP in order to achieve and maintain the NAAQS. *See* CAA section 110(a)(2)(C). The CAA and EPA's regulations are less prescriptive regarding minimum requirements for minor NSR, so air agencies generally have more flexibility in designing their minor NSR programs.

B. What is project aggregation?

As described in the preceding section, the EPA's implementing regulations for NSR establish a two-step process for determining major NSR applicability for projects at stationary sources. To be subject to major NSR requirements, the project must result in both (1) a significant emissions increase from the project (the determination of which is called "Step 1" of the NSR applicability analysis, or "project emissions accounting"); and (2) a significant *net* emissions increase at the stationary source, taking account of emission increases and emission decreases attributable to other projects undertaken at the stationary source within a specific time frame (called "Step 2" of the NSR applicability analysis, or "contemporaneous netting"). This approach to applicability makes it necessary to accurately define what constitutes the "project" under review to ensure that the proper emissions increase resulting from the project is used when comparing it with the applicable NSR significance threshold at Step 1 of the NSR applicability analysis.[4] Otherwise, a source could

[1] 40 CFR 51.165(a)(1)(xxxvii), 40 CFR 51.166(b)(49), 40 CFR 52.21(b)(50).

[2] For PSD, the statute uses the term "major emitting facility" which is defined as a stationary source that emits, or has a PTE, at least 100 tons per year (TPY) if the source is in one of 28 listed source categories—or at least 250 TPY if the source is not—of "any air pollutant." CAA 169(1). For NNSR, the emissions threshold for a major stationary source is 100 TPY, although lower thresholds may apply depending on the degree of the nonattainment problem and the pollutant. 40 CFR 51.165(a)(1)(iv)(A).

[3] 40 CFR 51.165(a)(1)(iv). 40 CFR 51.166(b)(1)(i). 40 CFR 52.21(b)(1)(i).

[4] In this notice, we use the terms "project," "changes," and "activities" interchangeably in referring to physical or operational changes that occur at a facility. In some cases, particularly in using the term "activities," we are actually referring to "sub-projects" that are nominally separate in scope but are nevertheless related to other sub-projects such that they all are part of a larger single project when determining NSR applicability. It is important to note that our use of the term "activities" in this notice is not intended to imply that every "activity" at a plant is a physical or operational change. The EPA recognizes that there are numerous activities undertaken at a facility, of which only a subset will constitute "changes" under the NSR regulations.

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closer in time are more likely to be substantially related than activities separated by larger time frames. Thus, it affirmed that the timing between activities remains important from a standpoint of framing the analysis of whether a substantial technical or economic relationship exists.

The 2009 NSR Aggregation Action also expressed that the farther apart projects are timed, the less likely they are to be substantially related, since the activities would likely be part of distinct planning and capital-funding cycles. It stated "the passage of time provides a fairly objective indicator of nonrelatedness between physical or operational changes. Specifically, the greater the time period between activities, the less likely that a deliberate decision was made by the source to split an otherwise 'significant' activity into two or more smaller, non-major activities." 74 FR 2380.

To this end, the 2009 NSR Aggregation Action affirmed that timing could be a basis to not aggregate separate projects, and it established a policy of applying a rebuttable presumption against aggregating projects that occur 3 or more years apart. The EPA justified its selection of 3 years as the presumptive timeframe in part by reasoning that it "is long enough to ensure a reasonable likelihood that the presumption of independence will be valid, but is short enough to maintain a useful separation between relevant construction cycles, consistent with industry practice. For example, in the case of electric utilities, a commenter explained that companies plan and schedule major turbine outages every four to five years." *Id.* However, the EPA did note that this presumptive timeframe may be rebutted in certain circumstances. For instance, the 2009 NSR Aggregation Action noted that where there is "evidence that a company intends to undertake a phased capital improvement project" where the activities "have a substantial economic relationship," this would likely overcome the presumption that those activities should not be aggregated. *Id.*

With regard to implementing the 3-year presumption, the EPA stated "the time period separating physical or operational changes should be calculated based on time of approval (*i.e.*, minor NSR permit issuance). If a permit has not been, or will not be, issued for the physical or operational changes, the time period should be based on when construction commences on the changes." 74 FR 2381.

The EPA also explained that a statement within the 3M Memorandum was potentially vulnerable to misapplication and did not properly reflect the "substantially related" criterion. The 3M Memorandum stated the following:

> Some minimum level of research activity and commensurate emissions, source-wide, perhaps could be expected from year to year, as would be expected to keep the 3M plant productive or operable. These emissions and thereby modifications cannot be presumed to be independent given the plant's *overall basic purpose* to support a variety of research and development activities. Therefore, even though each research project may have been individually conceived and separately funded, it is appropriate to look at the overall expected research activity in assessing NSR applicability and enforcement. 3M Memorandum at 5 (emphasis added).

In the 2009 NSR Aggregation Action, the EPA expressed concern with this statement from the 3M Memorandum, saying "it could be interpreted to imply that almost any activity is related to any other activity at that source simply because they are both capital investments and support the company's goal to make a profit." 74 FR 2376, 2379. The suggestion that all changes consistent with the "overall basic purpose" of the plant can and should be aggregated is inconsistent with the interpretation of "project" to include only those changes that have a substantial relationship. While the EPA did not, in the 2009 NSR Aggregation Action, find such a broad approach to project aggregation was often applied after the 3M determination, we nevertheless had concerns that it did not represent an appropriate criterion for aggregating projects for NSR purposes and could be misapplied. Thus, in the 2009 NSR Aggregation Action, we maintained that two nominally separate projects are not substantially related if they are only related to the extent that they both support the source's "overall basic purpose."

In summarizing what it means for projects to be substantially related, the 2009 NSR Aggregation Action provided that "in most cases, activities occurring in unrelated portions of a major stationary source (*e.g.*, a plant that makes two separate products and has no equipment shared among the two processing lines) will not be substantially related. The test of a substantial relationship centers around the interrelationship and interdependence of the activities, such that substantially related activities are likely to be jointly planned (*i.e.*, part of the same capital improvement project or engineering study), and occur close in time and at components that are functionally interconnected." 74 FR 2378. The 2009 NSR Aggregation Action added, "[t]o be 'substantially related,' there should be an apparent interconnection—either technically or economically—between the physical and/or operational changes, or a complementary relationship whereby a change at a plant may exist and operate independently, however its benefit is significantly reduced without the other activity. We note that these factors are not necessarily determinative of a substantial relationship, but are merely indicators that may suggest that two or more activities are likely to be substantially related and, therefore, candidates for aggregation." *Id.*

2. Reconsideration and Administrative Stay

On January 30, 2009, the Natural Resources Defense Council (NRDC) submitted a petition for reconsideration of the 2009 NSR Aggregation Action (the "NRDC Petition"). In response to the NRDC Petition, on February 13, 2009, the EPA convened a proceeding for reconsideration as provided for under the CAA section 307(d)(7)(B), finding that the petitioner had raised objections to the action that arose after the comment period and that were of central relevance to the action.

To allow time to complete the reconsideration prior to the 2009 NSR Aggregation Action becoming effective, the EPA announced a 90-day administrative stay of the action. *See* 74 FR 7284 (February 13, 2009). The EPA subsequently completed an action to further delay the effective date until May 18, 2010. *See* 74 FR 22693 (May 14, 2009). On May 18, 2010, the EPA invoked APA section 705 to stay the action indefinitely pending the proceedings for judicial review or the completion of reconsideration. These stays were intended to allow the EPA the time to take comment on issues that were in question and complete any revisions of the action that became necessary as a result of the reconsideration process.

As part of the reconsideration proceeding, on April 15, 2010, the EPA published a proposed reconsideration of the 2009 NSR Aggregation Action (the "2010 Reconsideration Proposal").[14] 75 FR 19567. At the time, the EPA considered whether some of the points

[14] In the 2010 Reconsideration Proposal, the EPA described the 2009 action as the "NSR Aggregation Amendments." However, since this action did not "amend" the NSR regulations, but rather laid out an interpretation of our current regulations and described a policy on timing for aggregation, the 2009 action is more appropriately described, as it is described herein, as the 2009 NSR Aggregation Action.

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conceivably carve up a higher-emitting project into two or more lower-emitting "projects" and avoid triggering major NSR requirements.[5] "Project aggregation," therefore, ensures that nominally-separate projects occurring at a source are treated as a single project for NSR applicability purposes where it is unreasonable not to consider them a single project.[6]

As with certain other aspects of the NSR program, determining what constitutes the "project" is a case-by-case decision that is both site-specific and fact-driven. There is no pre-determined list of activities that should be aggregated for a given industry or industries. It is, therefore, necessary to establish criteria for determining when nominally-separate activities are considered one project under NSR. The EPA has specifically sought to develop principles for aggregating changes such that a project is appropriately defined by the source, so that the emission increases attributable to the project are accurately quantified for purposes of analyzing NSR applicability. Over the years, the EPA articulated its policy on project aggregation through a series of statutory and regulatory interpretations contained in EPA letters and memoranda, the most commonly cited being a 1993 EPA memorandum regarding NSR applicability for activities that had occurred at a 3M facility in Minnesota.[7]

To date, the EPA's focus in formulating criteria for project aggregation has been to ensure that NSR is not circumvented through some artificial separation of activities at Step 1 of the NSR applicability analysis where it would be unreasonable for the source to consider them to be separate projects. However, in a March 13, 2018, memorandum[8] on the topic of "project emissions accounting," the EPA broached the question of whether it might also somehow be possible for a source to circumvent NSR through some wholly artificial grouping of activities to include decreases in emissions as part of Step 1 of the NSR applicability analysis—*i.e.*, assessing whether a project by itself results in a significant emissions increase before reaching Step 2, where one then determines whether there will be a significant net emissions increase by taking into account all contemporaneous increases and decreases across the source. While we[9] have been mindful of this question in deciding to employ the project aggregation criteria described in this action, we intend to address more fully this scenario in the context of a subsequent rulemaking action on the topic of project emissions accounting.

C. Regulatory History

1. The 2009 NSR Aggregation Action

On January 15, 2009, the EPA published a final action—which we are calling the "2009 NSR Aggregation Action"—that described the principles of project aggregation that we would apply when determining whether a source had unreasonably segregated a single project into multiple projects, thereby circumventing the NSR permitting requirements.[10] We had initially proposed in 2006 to establish principles for project aggregation through an amendment to the NSR regulations.[11] However, because of the difficulty of creating a bright line to determine when activities should be aggregated, we ultimately decided not to adopt the proposed changes to the regulations and elected instead to pursue a less prescriptive approach by describing, in the 2009 action, the EPA's interpretation of the existing regulations and a policy for applying that interpretation going forward.

The 2009 NSR Aggregation Action called for sources and reviewing authorities to aggregate emissions from nominally-separate activities when they are "substantially related" for the purpose of determining whether they are a single modification resulting in a significant emissions increase under NSR at Step 1.[12] This "substantially related" criterion is based on an interpretation of the term "project" contained in the major NSR regulations.[13] The action also included a statement that the EPA would, as a matter of policy, establish a rebuttable presumption that activities that occurred more than three years apart are not "substantially related" and therefore, generally, should not be aggregated for purposes of determining whether they are a single modification at Step 1.

The 2009 NSR Aggregation Action retained the existing rule text defining the term "project"—*i.e.*, "a physical change in, or change in method of operation of, an existing major stationary source"—and interpreted this rule text to mean that sources and permitting authorities should combine emissions only when nominally-separate changes are "substantially related." While acknowledging the case-specific nature of a project aggregation determination, the 2009 NSR Aggregation Action described the factors that should be considered when evaluating whether changes are substantially related, including technical or economic dependence. It also offered examples of what it means to be substantially related, and it referenced examples provided in EPA's 2006 proposed rule on project aggregation to further amplify EPA's meaning of the term. Thus, in many respects, the "substantially related" interpretation in the 2009 NSR Aggregation Action was intended to encompass principles for aggregating projects that were similar to those that the EPA had proposed in 2006, but ultimately concluded should not be prescriptively defined in a regulation because of the difficulty of developing a bright line for determining when activities should be aggregated.

The 2009 NSR Aggregation Action specifically addressed the timing element of project aggregation decisions in multiple ways. It affirmed that timing alone should not be a basis for aggregating projects because the appropriate basis for aggregation is whether there is a substantial technical or economic relationship. It further explained that activities that occur simultaneously should not be presumed to be substantially related, although it is reasonable to presume that activities

[5] Emission changes from separate projects (not included under Step 1 as falling within the project under review) are considered at Step 2 if they are "contemporaneous" and "otherwise creditable" under the NSR regulations. *See* 40 CFR 52.21(b)(3).

[6] It is not permissible to seek to circumvent NSR by securing several minor NSR permits for individual projects with the effect of avoiding major NSR requirements for what is actually a single project.

[7] Memorandum from John B. Rasnic, Director, Stationary Source Compliance Division, OAQPS, to George T. Czerniak, Chief, Air Enforcement Branch, EPA Region 5, titled, "Applicability of New Source Review Circumvention Guidance to 3M—Maplewood, Minnesota" (June 17, 1993) (hereinafter "3M Memorandum").

[8] Memorandum from E. Scott Pruitt, Administrator, to Regional Administrators, titled, "Project Emissions Accounting Under the New Source Review Preconstruction Permitting Program" (March 13, 2018) (hereinafter "Project Emissions Accounting Memorandum").

[9] In this preamble, the terms "we", "our" and "us" refer to the EPA.

[10] Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Aggregation and Project Netting (74 FR 2376; January 15, 2009).

[11] Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Debottlenecking, Aggregation, and Project Netting (71 FR 54235; September 14, 2006).

[12] *See* 74 FR 2378 ("When there is no technical or economic relationship between activities *or where the relationship is not substantial*, their emissions need not be aggregated for NSR purposes." (emphasis added)). That is, mere relatedness is not sufficient to upend the source's definition of its project, but sources cannot circumvent NSR by artificially separating a series of emissions-increasing projects into separate projects that fall below the significance thresholds.

[13] *See, e.g.*, 40 CFR 52.21(b)(52).

change from the interpretation that the EPA had articulated in 2006 and earlier. In addition, since we understood the *Paralyzed Veterans* opinion to require a notice-and-comment rulemaking process when an agency wished to change a regulatory interpretation (which, under the APA, would constitute the issuance of an "interpretive rule," or, as we refer to it herein, an "interpretation"), and because the 2009 NSR Aggregation Action had completed a notice-and-comment rulemaking process that had originally proposed to amend rule text, we chose in the 2010 Reconsideration Proposal to apply the procedures for reconsidering a "legislative rule."

The United States Supreme Court has since abrogated the *Paralyzed Veterans* doctrine, ruling that it was inconsistent with the APA, which by its plain terms does not require agencies to go through a notice-and-comment process in issuing an interpretive rule. *Perez* v. *Mortgage Bankers Association*, 135 S. Ct. 1199 (2015). Because the 2009 NSR Aggregation Action did not impose legally binding obligations or prohibitions on regulated entities or state permitting authorities, it was not a legislative rule. Since the 2009 NSR Aggregation Action was a combination of interpretation and policy statement, it could have been issued by the EPA without following notice-and-comment rulemaking procedures. 5 U.S.C. 553(b); 42 U.S.C. 7607(d)(1). Further, to the extent the interpretation reflected therein is a change from a prior interpretation, after the Supreme Court decision in *Mortgage Bankers*, it is now clear that an agency may also change such an interpretation of its regulations without the need to publish notice in the **Federal Register** and solicit public comment. However, because the EPA has been using notice-and-comment rulemaking procedures up to this point, the EPA believes it is prudent, but not required, in order to retain the interpretation of the NSR regulations with regard to project aggregation that we published in 2009, that we publish this document in the **Federal Register**. This procedure also allows us to complete the reconsideration proceeding and lift the indefinite administrative stay of the 2009 NSR Aggregation Action. We also believe that it is prudent to respond to those comments we received during the reconsideration process.

III. This Action

A. Overview

In this action, we are taking final action on reconsideration of the issues for which we asked for comment in the 2010 Reconsideration Proposal. The proposal invited comment on all issues alleged in the petition for reconsideration, including the following: Lack of adequate opportunity for notice and comment on the final action; legal inconsistency with a prior court decision; lack of demonstrated need for a policy change; and lack of clarity over state plan adoption of the action.

This action addresses all of the petitioner's issues. Moreover, to the extent that commenters lacked an adequate notice-and-comment opportunity in the development of the 2009 NSR Aggregation Action, the reconsideration process has addressed this deficiency by inviting comment in 2010 on the issues raised by the petitioner. This action (1) takes final action on the 2010 Reconsideration Proposal and retains the 2009 NSR Aggregation Action without adopting any changes to the rule text or the interpretation and statement of policy contained therein; (2) completes the CAA section 307 reconsideration proceeding on the 2009 NSR Aggregation Action to address any potential notice-and-comment deficiency; and (3) lifts the APA section 705 stay of the 2009 NSR Aggregation Action. The conclusions reached and expressed in this final action are based on careful review of the public comments on the 2010 Reconsideration Proposal.[16]

This final decision on reconsideration of the 2009 NSR Aggregation Action does not finalize the 2010 Reconsideration Proposal's preferred option to revoke the 2009 NSR Aggregation Action's interpretation and policy. Upon reviewing public comments, after further deliberation, and taking account of the Administration's priorities and policy goals, the EPA has concluded that the interpretation and policy in the 2009 NSR Aggregation Action should be retained.[17] We believe the 2009 NSR Aggregation Action articulates a reasonable standard for aggregating related projects and is consistent with the CAA and our regulations.

With regard to the petitioner's concern about how the 2009 NSR Aggregation Action applies to EPA-approved permitting programs, we affirm our decision in 2009 not to revise the current rule text, and instead to conclude that the terms "project" and "a physical change in, or change in method of operation of" in the existing NSR regulations can be reasonably interpreted as already incorporating the "substantially related" test set forth in the 2009 preamble. Because the 2009 NSR Aggregation Action did not amend the rule text, state and local air agencies with approved state implementation plans (SIPs) are not required to amend those plans to adopt this interpretation that projects should be aggregated when "substantially related." If state and local agencies want to adopt this interpretation, we believe that in most cases this interpretation can be applied without formal adoption into their rules. We encourage state and local air agencies to follow this interpretation to ensure greater national consistency in making NSR applicability determinations, though state and local air agencies with approved SIPs can continue to apply their own interpretation of the scope of a "project."

Consistent with comments received on the EPA's 2006 proposed rule, commenters on the 2010 Reconsideration Proposal raised concerns with the clarity of our prior policy on project aggregation, which was developed over time through a number of *post hoc* site-specific applicability determinations. We anticipate the 2009 NSR Aggregation Action will reduce any confusion over our past policy and provide sources and regulators with increased clarity when determining whether projects should be aggregated for NSR purposes. The EPA believes the principles outlined in the 2009 NSR Aggregation Action will not only help to achieve greater national consistency in project aggregation determinations but will also streamline NSR permitting by reducing the time needed to assess whether nominally-separate physical and operational changes should be aggregated for NSR applicability purposes.

As this action officially completes our reconsideration proceeding, we are also lifting the APA section 705 stay and announcing the effective date of the 2009 NSR Aggregation.

[16] In the docket for this action, we are making available a document, "Response to Public Comments for Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Aggregation; Reconsideration", in which the EPA responds to the public comments received on the 2010 Reconsideration Proposal.

[17] *See* Presidential Memorandum on Streamlining Permitting and Reducing Regulatory Burdens for Domestic Manufacturing (82 FR 8667; January 24, 2017); Executive Order 13777 on Enforcing the Regulatory Reform Agenda (82 FR 12285, March 1, 2017).

raised by the NRDC petition might demonstrate potential flaws in the process and with fundamental aspects of the 2009 NSR Aggregation Action, including the legal basis, state adoption and implementation, and the clarity of the "substantially related" criterion. In the 2010 Reconsideration Proposal, we expressed agreement with the petitioner on a number of fronts, invited comment on all issues raised in the NRDC petition, and proposed a preferred option to revoke the 2009 NSR Aggregation Action. The 2010 Reconsideration Proposal also referenced a number of the past determinations on project aggregation. *See* 75 FR 19570–1.

The EPA received a total of 27 comments on our 2010 Reconsideration Proposal. Of those commenters, 20 represented industry parties, three represented state and local air agencies, one represented a tribal government agency, one represented a federal agency, one represented an environmental advocacy group, and one was a private citizen.

3. Characterizing the 2009 NSR Aggregation Action

In the history of actions that the EPA has taken regarding its project aggregation policy since 2006, the EPA has variously described the 2009 NSR Aggregation Action as a "rule," "interpretation," and "policy." However, we are now mindful that these terms may be used to refer to three distinct types of agency action that have varying degrees of legal effect and can be changed through different types of procedures. *National Mining Association* v. *McCarthy*, 758 F.3d 243, 251–52 (D.C. Cir. 2014). As is explained below, the distinction between the proper procedures for changing rules, interpretations, and policies were not as clear to the agency in 2009 and 2010 as they are today. Recent court decisions have provided more clarity regarding the distinction between these types of actions and the means through which an agency can change them. In order to clarify how state and local permitting authorities may apply the principles for project aggregation that the EPA articulated in 2009, in this final action we seek to address any confusion regarding the nature of that 2009 action.

We begin by defining what we understand each of these terms to mean when they are used in the discussion that follows. We use the term "rule" to describe a "legislative rule," which is "[a]n agency action that purports to impose legally binding obligations or prohibitions on regulated parties—and that would be the basis for an enforcement action for violations of those obligations or requirements." *National Mining*, 758 F.3d at 251–52. We use the term "interpretation" to describe "an agency action that merely interprets a prior statute or regulation, and does not itself purport to impose new obligations or prohibitions or requirements on regulated parties." *Id.* Following the language in the APA, courts have used the term "interpretive rule" to describe this type of action. *Id.* Here, however, we use the term "interpretation" to more clearly distinguish such an action from a *legislative* rule. Finally, a "policy" or "statement of policy" is "an agency action that merely explains how the agency will enforce a statute or regulation—in other words, how it will exercise its broad enforcement discretion or permitting discretion under some extant statute or rule." *Id.*

In 2006, we proposed a rule (meaning a *legislative* rule) that would have changed the text in the Code of Federal Regulations. We included in the preamble an explanation of what we intended that proposed regulatory text to mean. 71 FR 54235 (September 14, 2006). In that **Federal Register** document, we referred to the action as a "proposed rule." *Id.*; *see also* 71 FR at 54245 ("We are proposing to add our aggregation policy to our NSR regulations . . ."). In 2009, we took "final action" in the matter. That is, we completed the action begun in 2006, while not changing the regulatory text itself. 74 FR 2376. In retaining the existing regulatory text defining the term "project," we said that the action we were taking "interprets that rule text." *Id.* The interpretation offered in the 2009 NSR Aggregation Action was that a "project," which the regulatory text defines to mean "*a* physical change in, or change in the method of operation of, an existing major stationary source," 40 CFR 52.21(b)(53) (emphasis added), includes those activities that are "substantially related." 74 FR 2377. This portion of the 2009 NSR Aggregation Action was an interpretation.[15] Although we had proposed to adopt a legislative rule in 2006 and to reflect that in amended regulatory text, we made a final decision in 2009 not to adopt any legislative rule or to amend the text of the NSR regulations. Instead, we chose to announce an interpretation of the *existing* regulations that drew from EPA's prior experience on the topic of project aggregation, but which to some degree altered the aggregation policy that the EPA had previously articulated in past guidance memoranda and letters.

In 2009, we also discussed our intention to apply a rebuttable presumption that activities separated by more than 3 years would not be considered substantially related. This section of the action is best understood as a statement of policy, as we were describing how we intended to exercise our discretion under the NSR regulations, as we interpreted them. We justified the 3-year presumption as a commonsense approach, in that we believed that in practice once 3 years had passed, "it is difficult to argue that th[e activities] are *substantially* related and constitute a single project." 74 FR 2380. But recognizing that there may be situations that would warrant an exception to this approach, we indicated that the 3-year presumption would be rebuttable. We indicated our view that it would be allowable and appropriate for other permitting authorities to "also adopt this presumptive timeframe as guidance for their sources." 74 FR 2381.

The 2009 action, thus, contained both an interpretation of the existing regulations and a statement of policy on how we intended to implement that interpretation. It is for this reason that we refer to it as the 2009 NSR Aggregation Action. However, when reconsidering that 2009 action, we were not sufficiently clear in the 2010 Reconsideration Proposal regarding the nature of the action we were reconsidering. At times, we described the 2009 action as a "final rule," and called it the "NSR Aggregation Amendments," which could be read to suggest that we considered the 2009 NSR Aggregation Action, despite the lack of regulatory text changes, to somehow be a *legislative* rule, or something that "amended" the existing regulations.

Much of the confusion stemmed from the fact that at the time we took these actions, judicial precedent in the United States Court of Appeals for District of Columbia Circuit (D.C. Circuit) provided that, where an agency had given a definitive interpretation to one of its own legislative rules, the agency could not thereafter change that interpretation without providing notice and an opportunity to comment. *Paralyzed Veterans of America* v. *D.C. Arena L.P.*, 117 F.3d 579 (D.C. Cir. 1997). In part because of this precedent, we were persuaded in 2010 that we should provide an opportunity for the public to comment on the 2009 interpretation, which could have been viewed as a

[15] As explained above, courts follow the APA in referring to this type of action as an "interpretive rule," but we refer to it herein simply as an "interpretation" to more clearly distinguish such an action from a *legislative* rule.

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"substantially related" test is an appropriate standard for project aggregation.

As explained elsewhere in this document, the nature of the project aggregation determination is case-specific, which means it is inherently difficult to establish a bright line standard: Such a standard may be reasonable when conducting an evaluation of project scope in one situation, but could prove to be unreasonable or unworkable when applied in other situations. This case-by-case aspect necessitates that the EPA establish a reasonable general principle to apply, and we believe the "substantially related" criterion is an appropriate principle for concluding that claimed separate projects are a single project for NSR applicability purposes. We believe the substantially related criterion is sound from a policy and implementation perspective.

The 2009 NSR Aggregation Action effectively addresses certain past EPA statements in relation to implementing the "substantially related" test for future project aggregation determinations. The 2009 NSR Aggregation Action outlined the role of timing—specifically, that timing alone is not determinative of whether activities are substantially related and that, as a policy matter, activities separated in time by three or more years may be presumed to be not substantially related. The 2009 NSR Aggregation Action also rejected the use of an "overall basic purpose" criterion for aggregating physical or operational changes, since it could have been read to constitute an open-ended standard, resulting in the unreasonable or improper aggregation of unrelated activities.

Importantly, we do not believe the 2009 NSR Aggregation Action reflects a major shift in policy from EPA's prior policy on project aggregation. To the contrary, we believe that in many ways the 2009 NSR Aggregation Action clarifies and supplements previous statements of policy. For example, in the case of timing, the 3M Memorandum suggested that when minor NSR permit applications occur "over a short time period (*e.g.*, 1 year or 18 months), the modifications *may* require major new source review." 3M Memorandum at 4 (emphasis added). Thus, the 3M Memorandum never said timing was the sole criterion or otherwise conclusive. Rather, timing was a reason to look more closely at the relevant activities' "intrinsic relationship with each other (physical proximity, stages of production process, etc.) and their impact on economic viability of the plant (scheduling down time in light of production targets, economies of scale, etc.)." *Id.* Similarly, the 2009 NSR Aggregation Action said that "whether a physical or operational change is dependent on another for its viability is still a relevant factor in assessing whether the changes should be aggregated," and "substantially related activities are likely to be jointly planned (*i.e.*, part of the same capital improvement project or engineering study), and occur close in time and at components that are functionally interconnected." 74 FR 2378.

In addition, the "substantially related" criterion is not materially different from the factors the agency has considered in previous project aggregation decisions. Over time, the EPA has used various terms and phrases—*e.g.*, "intrinsic relationship" as was used in the 3M Memorandum—to describe the basis for why multiple nominally-separate changes at a source should be treated as a single project for NSR applicability purposes. The term "substantially related" is, therefore, little more than a functional synonym for other terms that the EPA has historically used to characterize its project aggregation policy. While sources and permitting authorities making project aggregation determinations may continue to use the EPA's previous terms, and may rely on other terms or phrases going forward, we believe that the terminology used should ultimately express a standard for determining whether the activities are or are not substantially related. Thus, we believe "substantially related" works effectively as an umbrella term to include these previous descriptors for analyzing the relationship between projects that warrant aggregation.

Finally, the matter of defining the scope of a project was raised, in a different context, in the Project Emissions Accounting Memorandum issued on March 13, 2018. There, we observed that, as general matter, the source itself is responsible for defining the scope of its own project, subject to the limitation that the source cannot seek to circumvent NSR by characterizing the proposed project in a way that would separate a single project into multiple projects. We further pointed out that, "[s]ubject to the equivalent understanding that it might be possible [for a source] to circumvent NSR through some wholly artificial *grouping* of activities, the EPA does not interpret its NSR regulations as directing the agency to preclude a source from reasonably defining its proposed project broadly, to reflect multiple activities." [18]

In the Project Emissions Accounting Memorandum, we noted that EPA was then evaluating whether to undertake a future notice-and-comment rulemaking to implement, through changes to the regulatory text itself, the interpretation of the NSR applicability provisions set forth in the memorandum. At such time as we proceed with that rulemaking, we will look to provide further guidance with respect to properly accounting for the scope of a project in which a source is seeking to take account of emission decreases at Step 1 of the NSR applicability analysis. Meanwhile, in advance of that rulemaking, we take the opportunity here to clarify that, as a general matter, it is neither necessary nor appropriate to take into consideration such matters as whether emission decreases attributable to a particular activity are "integral" to the overall project, as had once been proposed by a petroleum refinery to the EPA.[19] Our current view is that the concerns regarding the real possibility that NSR might be circumvented through some artificial separation of activities where it would be unreasonable to consider them separate projects—*i.e.*, the concerns which the 2009 NSR Aggregation Action is intended to address—are not so obviously presented by the situation where a source itself is choosing to group together, as a single project, activities to which a projected emissions decrease is attributable.[20] In a future rulemaking to clarify, through regulatory text changes, the interpretation set forth in the Project Emissions Accounting Memorandum, the EPA will be taking comment on whether our current view of this issue is reasonable, whether the "substantially related" criterion described here may speak to this issue, and other related matters.

3. Legal Basis Is Sound

We believe the 2009 NSR Aggregation Action is legally supportable and makes sense for sometimes difficult case-by-

[18] Project Emissions Accounting Memorandum at 9 (emphasis added).

[19] Letter from Steven C. Riva, U.S. EPA Region 2, to Kathleen Antoine, HOVENSA, LLC, "Re: Emission Decreases Integral to Projects" (June 7, 2010) ("EPA, by this letter, is not opining on the merits of HOVENSA's analysis regarding the underlying basis for 'integral to the project' approach.").

[20] Indeed, the EPA views this latter situation as one where sources could potentially be incentivized to seek out emission reductions that might otherwise be foregone entirely—*e.g.*, because of perceived complexity with contemporaneous netting under Step 2 of the NSR applicability analysis.

B. Retaining the 2009 NSR Aggregation Action

1. An Interpretation Is Needed

As explained earlier in this document, the EPA's past position on project aggregation—prior to the 2009 NSR Aggregation Action—was not established through a rule or through a single, comprehensive policy statement. Rather, the policy had been articulated by the EPA through a number of site-specific determinations, many of which were issued after the activities subject to the determination had already occurred. Navigating this collection of EPA statements, capturing their salient points, and determining whether and how to apply their rationale to new determinations with different fact patterns was arguably a challenge for sources and permitting authorities over the years. Such an approach lacked clarity for sources and permitting authorities, making it sometimes difficult to understand the overall policy so they could effectively apply it prospectively.

There is a substantive distinction between making case-by-case determinations after-the-fact and making case-by-case determinations prospectively—*i.e.*, as part of a permitting applicability review—for NSR purposes. Many *post hoc* determinations are made with an eye to determining whether the requirements of NSR were circumvented, whereas prospective determinations are made with the purpose of giving sources an opportunity to evaluate modifications during the planning or preconstruction phase in order to determine whether a planned or proposed modification requires a PSD or NNSR permit, so as *not* to circumvent the NSR process. While the underlying criteria for assessing whether to group multiple activities as a single project should be the same regardless of whether the determination is prospective or *post hoc*, a *post hoc* determination is often very specific to the industry and the individual fact pattern under consideration, and therefore applying the determination's rationale prospectively, while potentially informative, could be misapplied to situations involving different industries or having different fact patterns. The 2009 NSR Aggregation Action also recognized the limitations of having a policy that is based on the specific fact patterns of past determinations: "the decision to aggregate or disaggregate activities is highly case-dependent, such that letters and memoranda that opine on whether to aggregate a particular set of activities at one facility are not necessarily transferable to a decision to aggregate a similar set of activities but with a slightly different set of circumstances at a different plant." 74 FR 2377.

Previous agency statements can be taken out of context or misunderstood when reviewing projects having a different set of facts. For example, while the 3M Memorandum was considered by some as the EPA's guiding policy on project aggregation, parties could certainly misconstrue portions of that statement to suggest that all projects occurring within the same timeframe should be aggregated, or that all projects occurring at a facility should be aggregated as long as they contribute to the source's "overall basic purpose." Such an approach—*i.e.*, to aggregate projects simply because they may occur close in time or may support the same overall purpose of the facility—fails to take proper account of the actual interrelationship of activities. Meanwhile, in other parts of the 3M Memorandum, the EPA's statements clearly indicate that, in order to justify aggregating activities for purposes of major NSR, the reasonable approach is to determine whether those activities are related in some meaningful way: *e.g.*, "[a]uthorities should scrutinize [permit] applications *that relate to the same process or units* . . ."; "two or more *related* minor changes over a short time period should be studied for possible circumvention." 3M Memorandum at 3 (emphasis added). We consequently do not believe that a broader approach to aggregating activities—*i.e.*, based on their contribution to a plant's overall purpose—is an accurate characterization of the EPA's view at the time of the 3M determination. Furthermore, we do not believe it reflects EPA's view in any other statement made by the agency over the years.

We noted in the 2010 Reconsideration Proposal that "in reviewing the record for the NSR Aggregation Amendments, we find that the only factual support for the contention that our historic approach caused confusion was anecdotal," and that the "parties supporting a change in policy failed to provide us with any characterization of the overall level of uncertainty or other problems resulting from the existing policy on aggregation." 75 FR 19572. However, after further consideration, the EPA finds this to be an insufficient basis for changing or revoking the 2009 NSR Aggregation Action. So-called "anecdotal" evidence is nevertheless still evidence of which the agency can properly take account if, in its judgment, it finds it to be meaningful. Indeed, the criticism of relying on "anecdotes" suggests that examples of problems offered in public comments should be ignored. The EPA is required to take into account the comments submitted. Furthermore, merely because the overall level of uncertainty demonstrated by public comments cannot be characterized—a given entity would not necessarily know whether others were as uncertain as they were—does not serve to demonstrate that the 2009 NSR Aggregation Action was unwarranted. We believe that the evidence before the EPA in 2009 and the agency's own extensive permitting experience, coupled with statements from public commenters in this reconsideration proceeding, clearly indicates that the EPA's prior policy on project aggregation lacked clarity and promoted confusion. The 2009 NSR Aggregation Action provides a more concise formulation for how to interpret the scope of a project and provides clarity for permitting authorities, regulated entities, and the public.

Finally, the 2010 Reconsideration Proposal states that "[w]hile the [2009 NSR Aggregation Action] may, in some respects, appear clearer than our previous policy, we are not convinced that it achieved enough additional clarity to improve the process of making aggregation assessments by sources and reviewing authorities. . . ." 75 FR 19573. After further consideration, we now believe that providing clarity in a single document is a better approach than continuing the previous policy that was based on a host of EPA letters and memoranda, which collectively provided less clarity. We recognize there will continue to be "gray areas" that sources and permitting authorities will ultimately have to work through in deciding whether or not to aggregate a set of changes at a facility. But this is attributable to the inherent nature of such decisions, not to some deficiency in the 2009 NSR Aggregation Action. That does not mean that the EPA should abandon the clarity it attempted to provide in that action.

2. "Substantially Related" Is an Appropriate Standard

As noted above, the EPA continues to believe that there is a need for *some* criteria for determining when nominally-separate changes should be considered a single "project" for purposes of determining NSR applicability. It remains necessary to draw a line between those activities that are to be considered a single "physical or operational change" and those that are not. In this action, we are affirming that the 2009 NSR Aggregation Action's

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that time," the EPA explained, states "may also begin applying EPA's interpretations to the extent they do not conflict with their approved SIPs." *Id.* We now believe it is likely that state and local permitting authorities would have understood this straightforward explanation.

Further, as previously discussed, determining whether a source has sought to circumvent NSR by failing to treat nominally-separate activities as a single project is inherently case-specific and fact-dependent. Given this, it is not reasonable to imagine that perfect clarity could ever be achieved. To the extent, however, that the 2009 NSR Aggregation Action, in setting forth both the "substantially related" interpretation and the EPA's policy for applying that interpretation, provides some meaningful guidance to sources and to state and local permitting authorities, we fail to understand how revoking the 2009 NSR Aggregation Action would serve to promote clarity.

Indeed, in this regard, we believe in most cases that sources and state and local air agencies already implement a standard that is similar to the substantially related standard. To the extent that a state or local air agency desires to formally adopt the 2009 NSR Aggregation Action, the EPA will provide support to those agencies to process SIP submittals and issue approvals, as warranted. In most cases, however, we do not think changes in state plans would be needed to implement this interpretation.

C. Completing the Reconsideration Proceeding

We believe that this final action addresses the concerns raised by the petitioner with respect to the 2009 NSR Aggregation Action—*e.g.*, adequate notice and logical outgrowth, the legal underpinnings of the action, state adoption, and our need to change or clarify our aggregation policy. Accordingly, this action concludes the reconsideration proceeding of the 2009 NSR Aggregation Action.

D. Lifting the Administrative Stay: Announcement of Effective Date

On May 18, 2010, after a series of temporary administrative stays of the 2009 NSR Aggregation Action, the EPA exercised the provisions of the APA section 705 to postpone the effectiveness of the action "until judicial review is no longer pending or the EPA completes the reconsideration process." 75 FR 27644. Since this action concludes the reconsideration proceeding, and we have affirmed the legal consistency and policy appropriateness of the 2009 NSR Aggregation Action, we are hereby lifting the indefinite administrative stay and announcing the effective date of the action. The effective date of the 2009 NSR Aggregation Action, published in the **Federal Register** on January 15, 2009 (74 FR 2376), and delayed on February 13, 2009 (74 FR 7284), May 14, 2009 (74 FR 22693), and May 18, 2010 (75 FR 27643), begins again on November 15, 2018.

IV. Environmental Justice Considerations

We believe that this action does not have any effect on environmental justice communities. Through this action, the EPA is affirming its interpretation that its current NSR regulations allow for the 2009 NSR Aggregation Action and, as such, no increased burden is expected for source owners, permitting authorities, or environmental justice communities.

V. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is a significant action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket.

VI. Judicial Review

Section 307(b)(1) of the CAA indicates which Federal Courts of Appeal have venue for petitions of review of final agency actions by the EPA under the CAA. This section provides, in part, that petitions for review must be filed in the U.S. Court of Appeals for the District of Columbia Circuit (i) when the agency action consists of "nationally applicable regulations promulgated, or final actions taken, by the Administrator" or (ii) when such action is locally or regionally applicable, if "such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination."

This action completes the reconsideration proceeding and makes effective the 2009 NSR Aggregation Action. The 2009 NSR Aggregation Action is an interpretation of NSR rule language that applies in every state and territory in the United States where EPA is the permitting authority. Therefore, to the extent that this action is a "final action," it is "nationally applicable" within the meaning of CAA section 307(b)(1).

Under section 307(b)(1) of the Act, to the extent that this action is judicially reviewable, petitions for judicial review of this action must be filed in the United States Court of Appeals for the District of Columbia Circuit by January 14, 2019.

VII. Statutory Authority

The statutory authority for this action is provided by section 301(a) of the CAA as amended (42 U.S.C. 7601(a)). This document is also subject to section 307(d) of the CAA (42 U.S.C. 7407(d)).

Dated: November 7, 2018.

Andrew R. Wheeler,

Acting Administrator.

[FR Doc. 2018–24826 Filed 11–14–18; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2017–0744; FRL–9985–45]

Azoxystrobin; Pesticide Tolerances

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes tolerances for residues of azoxystrobin in or on beet, sugar, roots and vegetable, root, except sugar beet, subgroup 1B. Syngenta Crop Protection, LLC requested these tolerances under the Federal Food, Drug, and Cosmetic Act (FFDCA).

DATES: This regulation is effective November 15, 2018. Objections and requests for hearings must be received on or before January 14, 2019, and must be filed in accordance with the instructions provided in 40 CFR part 178 (see also Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: The docket for this action, identified by docket identification (ID) number EPA–HQ–OPP–2017–0744, is available at *http://www.regulations.gov* or at the Office of Pesticide Programs Regulatory Public Docket (OPP Docket) in the Environmental Protection Agency Docket Center (EPA/DC), West William Jefferson Clinton Bldg., Rm. 3334, 1301 Constitution Ave. NW, Washington, DC 20460–0001. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the OPP Docket is (703) 305–5805. Please review the visitor instructions and additional information about the docket available at *http://www.epa.gov/dockets.*

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case determinations required for assessing whether to aggregate nominally-separate projects. Contrary to the petitioner's argument, the use of the term ''substantially related'' would not create a carve-out from the scope of the statutory definition of ''modification.''

Drawing on arguments made by NRDC in its petition, in 2010 we had postulated, while ''[m]uch of the emphasis'' of *New York* v. *EPA*, 443 F.3d 880 (D.C. Cir. 2006) (*New York II*) and other cases had been on whether the EPA ''could exclude small changes from being considered potential modifications as defined in the Act,'' the court's reasoning in *New York II* also applies to a rule that would split apart one change into separate changes in order to limit the applicability of NSR.'' 75 FR 19571. The D.C. Circuit's *New York II* decision had focused on whether the EPA's amendment to the ''routine maintenance, repair and replacement'' provision of the NSR regulations which provided that a specifically defined category of ''equipment replacement'' projects did not constitute a ''physical change or change in the method of operation,'' was lawful. The court in *New York II* held that it was *not* lawful, opining that the EPA ''must apply NSR whenever a source conducts an emissions-increasing activity that fits within one of the ordinary meanings of physical change.'' 443 F.3d at 885.

In the 2010 Reconsideration Proposal, we said we then read the D.C. Circuit's opinion as ''requir[ing] EPA to aggregate any group of small changes'' that were ''sufficiently related to 'fit[] within one of the ordinary meanings of 'physical change.' '' 75 FR 19571. In this regard, we said that we ''agree[d] with [NRDC's] contention that, to the extent that our 'substantially related' interpretation,'' as set forth in the 2009 NSR Aggregation Action, would ''exclude meanings that fit within a reasonable understanding of the ordinary meaning of 'any physical change,' '' that interpretation would ''impermissibly narrow the scope of CAA section 111(a)(4).'' *Id.* We sought comment on this analysis of the statute and *New York II*.

Upon further consideration and after reviewing the public comments on this reconsideration proposal, the agency does not read *New York II* as supportive of the notion that the ''substantially related'' interpretation set forth in the 2009 NSR Aggregation Action is somehow contrary to the language of CAA section 111(a)(4). While we had previously suggested that there might be some weight to NRDC's argument that the '' 'aggregation of nominally separate changes that are *not* substantially related' also may be within an ordinary meaning of physical change,'' 75 FR 19571, *citing* NRDC Petition at 5–6 (emphasis in original), we do not now perceive any merit in NRDC's assertion.

With NRDC's arguments in mind, the agency at one point read *New York II* as suggesting that the CAA ''prohibits EPA from picking and choosing among meanings of the phrase 'any physical change . . . or change in the method of operation' if it would result in omitting a common meaning that would subject an emission increase to review.'' 75 FR 19571. Based on this, we were concerned that, ''[i]f 'substantially related' would omit an ordinary, common meaning of physical change that would bring an emissions-increasing project under review, then the definition would eliminate a type of physical change that Congress intended to cover (*i.e.*, the change that consists of the group of nominally-separate changes that comprise a project but do not qualify as 'substantially related')." *Id.* Thus, we reasoned at the time ''that, to the extent that [the] 'substantially related' interpretation would exclude meanings that fit within a reasonable understanding of the ordinary meaning of 'any physical change,' '' then the 2009 NSR Aggregation Action ''would impermissibly narrow the scope of CAA § 111(a)(4).'' *Id.*

We now believe that such concerns were unwarranted. Upon further consideration, we do not view *New York II*, properly understood, as providing support for the proposition that a ''common meaning'' of a single ''change'' would include multiple changes, much less multiple, separate changes that are not substantially related, such as changes which are undertaken at a source at different times, or undertaken for different purposes, or which are otherwise unrelated to each other. That is, the EPA's current view is that nothing in *New York II* supports, much less compels, a reading of the CAA under which all ''nominally-separate changes'' are deemed to ''comprise'' a single ''project,'' where those changes are not substantially related. Nevertheless, under the interpretation reflected in the 2009 NSR Aggregation Action, multiple changes that are ''substantially related'' are to be considered to be one project for purposes of determining NSR applicability.

Finally, to the extent that NRDC argues that the aggregation of activities that are not substantially related into one activity that fits within the ordinary meaning of a physical change—and not aggregating those changes to compare to the significance level would violate *New York II*—it has provided no examples where that may be the case and have not followed the reasoning of their argument to its logical conclusion. This argument would require the EPA to prove a negative: That whatever interpretation or policy on aggregation we adopted would not exclude any level of aggregated activities that fit within the ordinary meaning of a physical change. This impossible task would mean that even the EPA aggregation policy prior to the 2009 NSR Aggregation Action was in violation of *New York II* because it allowed a facility to sometimes disaggregate activities when, if aggregated, they would fall within the ordinary meaning of physical change. A better approach to defining the scope of the ordinary meaning of physical change is to provide, as we did in the 2009 NSR Aggregation Action, a principle for source owners or operators to follow, here the ''substantially related'' principle, when defining the scope of ''a physical change in, or change in method of operation of,'' pursuant to 40 CFR 52.21(b)(52), in a particular case.

4. Adoption Is Not Mandatory

We acknowledge that, by not making any changes to the regulatory text, as had been proposed, it may have been somewhat unclear to some whether state and local air agencies have to adopt or implement the elements of the 2009 NSR Aggregation Action, and, if so, how they should do so. In the 2010 Reconsideration Proposal, we expressed our agreement with ''NRDC's assertion that the state and local implementation requirements of the NSR Aggregation Amendments are unclear,'' and that the ''question of whether a SIP amendment is required when the CFR remains unchanged is likely to cause confusion for reviewing authorities and other stakeholders.'' 75 FR 19572. Taking account of this confusion, the agency considered that it ''added support for our preferred position in this notice, which is to revoke'' the 2009 NSR Aggregation Action. *Id.*

We now find such concerns over potential ''confusion'' to have been overstated. In the Response to Comments document for the 2009 NSR Aggregation Action (2009 RTC), the agency had specifically noted that ''[s]ince we are not promulgating the proposed rule regulatory changes, we are not adding NSR minimum program elements that would require states to modify their SIP.'' 2009 RTC at 56. The agency continued that it would ''begin applying the interpretations laid out in the final action to activities that postdate actions after the effective date of the final rulemaking notice.'' *Id.* ''At

The EPA Administrator, Andrew R. Wheeler, signed the following notice on 10/22/2020, and EPA is submitting it for publication in the *Federal Register* (FR). While we have taken steps to ensure the accuracy of this internet version of the rule, it is not the official version of the rule for purposes of compliance. Please refer to the official version in a forthcoming FR publication, which will appear on the Government Printing Office's govinfo website (https://www.govinfo.gov/app/collection/fr) and on Regulations.gov (https://www.regulations.gov) in Docket No. EPA-HQ-OAR-2018-0048. Once the official version of this document is published in the FR, this version will be removed from the internet and replaced with a link to the official version.

6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 52

[EPA-HQ-OAR-2018-0048; FRL-10016-21-OAR]

RIN 2060-AT89

Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is promulgating revisions to its major New Source Review (NSR) applicability regulations to clarify when the requirement to obtain a major NSR permit applies to a source proposing to undertake a physical change or a change in the method of operation (*i.e.*, a project) under the major NSR preconstruction permitting programs. Under these programs, an existing major stationary source proposing to undertake a project must determine whether that project will constitute a major modification subject to the major NSR preconstruction permitting requirements by following a two-step applicability test. The first step is to determine if the proposed project would result in a "significant emissions increase" of a regulated NSR pollutant (Step 1). If the proposed project is determined to result in such an increase, the second step is to determine if the project would also result in a "significant net emissions increase" of that pollutant from the source (Step 2). In this action, we are promulgating revisions to our major NSR applicability regulations to clarify that both increases and decreases in emissions resulting from a proposed project can be considered in

Step 1 of the major NSR major modification applicability test. We refer to the consideration of emissions increases and decreases in Step 1 as project emissions accounting.

DATES: This final rule is effective on **[INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA-HQ-OAR-2018-0048. All documents in the docket are listed in the *https://www.regulations.gov* website. Although listed in the index, some information may not be publicly available, *e.g.*, Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy. Publicly available docket materials are available electronically through *https://www.regulations.gov*.

In addition, the EPA has a website for NSR rulemakings at: *https://www.epa.gov/nsr*. The website includes the EPA's proposed and final NSR regulations, as well as guidance documents and technical information related to preconstruction permitting.

FOR FURTHER INFORMATION CONTACT: For further information concerning this action, please contact Jessica Montañez, U.S. EPA, Office of Air Quality Planning and Standards, Air Quality Policy Division, Mail Code C504-03, 109 T.W. Alexander Drive, Research Triangle Park, NC 27709; by telephone at (919) 541-3407 or by email at *montanez.jessica@epa.gov*.

SUPPLEMENTARY INFORMATION: Throughout this document, wherever "we," "us," or "our" is used, we mean the EPA and wherever "reviewing authorities," or "air agencies" is used, we mean air pollution control agencies.

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I. General Information

A. Does this action apply to me?

Entities potentially affected directly by this action include sources in all industry categories. Entities potentially affected directly by this action also include state, local and tribal air pollution control agencies responsible for permitting sources pursuant to the major NSR programs requirements.

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this *Federal Register* document will be posted at *https://www.epa.gov/nsr*.

C. *How is this document organized?*

The information presented in this document is organized as follows:

I. General Information
  - A. Does this action apply to me?
  - B. Where can I get a copy of this document and other related information?
  - C. How is this document organized?

II. Background
  - A. The New Source Review Program
  - B. Major Modifications Under the NSR Program
  - C. Project Emissions Accounting
  - D. Legal Analysis and Policy Rationale

III. Final Action
  - A. Summary of Final Action
  - B. Comments Received and Basis for Final Action
    1. General Comments on the Proposal
    2. Revisions to Step 1 of the NSR Major Modification Applicability Test
    3. Legal Rationale
    4. Defining the Scope of a Project
    5. Monitoring, Recordkeeping and Reporting of Emissions Decreases in Step 1 of the NSR Major Modification Applicability Test
    6. Considering Emissions Decreases in Step 1 for Delegated and SIP-Approved Programs
    7. Environmental and Economic Impact Considerations of Project Emissions Accounting

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IV. Environmental Justice Considerations
V. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs
C. Paperwork Reduction Act (PRA)
D. Regulatory Flexibility Act (RFA)
E. Unfunded Mandates Reform Act (UMRA)
F. Executive Order 13132: Federalism
G. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments
H. Executive Order 13045: Protection of Children from Environmental Health and Safety Risks
I. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution or Use
J. National Technology Transfer and Advancement Act (NTTAA)
K. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations
L. Congressional Review Act (CRA)
M. Judicial Review
VI. Statutory Authority

II. Background

On August 9, 2019, the EPA proposed[1] to revise its major NSR applicability regulations to clarify when the requirement to obtain a permit applies to an existing major stationary source proposing to undertake a physical change or change in the method of operation (*i.e.*, project) under the major NSR preconstruction permitting programs. More specifically, the EPA proposed to revise its NSR applicability regulations to make it clear that both emissions increases and decreases that result from a given proposed project are to be considered in Step 1 of the NSR major modification applicability test in a process known as project emissions accounting.

In the subsections that follow, the EPA introduces the NSR program and summarizes information from the proposal, including: (1) what constitutes a major modification under the

[1] 84 FR 39244 (August 9, 2019).

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major NSR programs, (2) the project emissions accounting process and its place in the major modification applicability test, and (3) the legal rationale for the regulatory revisions that were proposed. The history of the EPA's treatment of emissions increases and decreases in Step 1 of the major modification applicability test, including the March 2018 Memorandum titled "Project Emissions Accounting Under the New Source Review Preconstruction Permitting Program,"[2] was provided in the notice of proposed rulemaking and will not be restated here. The public comment period for this proposed rule ended on October 8, 2019.

A. The New Source Review Program

As established under the Clean Air Act (CAA), the NSR program is a preconstruction permitting program that requires certain stationary sources of air pollution to obtain permits prior to beginning construction. The NSR permitting program applies to both new construction and to modifications of existing sources, regardless of whether the source is in an area where the national ambient air quality standards (NAAQS) have been exceeded (nonattainment area) or if the source is in an area where the NAAQS have not been exceeded (attainment or unclassifiable

[2] Letter from E. Scott Pruitt, to Regional Administrators, "Project Emissions Accounting Under the New Source Review Preconstruction Permitting Program," March 13, 2018 ("March 2018 Memorandum") available at: *https://www.epa.gov/sites/production/files/2018-03/documents/nsr_memo_03-13-2018.pdf*. As indicated in the proposal, the March 2018 Memorandum explained that "the EPA interpreted the current NSR regulations as providing that emissions decreases as well as increases are to be considered in Step 1 of the NSR applicability process, where those decreases and increases are part of a single project." More specifically, in the March 2018 Memorandum the EPA interpreted the current major NSR regulations to mean that emissions increases and decreases could be considered in Step 1 for projects that involve multiple types of emissions units in the same manner as they are considered for projects that only involve new or only involve existing emissions units.

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area). New construction and modifications that emit "regulated NSR pollutants"[3] over certain thresholds are subject to major NSR requirements, while smaller emitting sources and modifications may be subject to minor NSR requirements or be excluded from NSR altogether.

Major NSR permits for sources that are located in attainment or unclassifiable areas are referred to as Prevention of Significant Deterioration (PSD) permits. These permits can also cover pollutants for which there are no NAAQS. Major NSR permits for sources located in nonattainment areas and that emit pollutants above the specified thresholds for which the area is in nonattainment are referred to as nonattainment NSR (NNSR) permits. The pollutant(s) at issue and the air quality designation of the area where the facility is located or proposed to be built determine the specific permitting requirements. The CAA requires sources subject to PSD to meet emission limits based on Best Available Control Technology (BACT) as specified by CAA § 165(a)(4), and sources subject to NNSR to meet Lowest Achievable Emissions Rate (LAER) pursuant to CAA § 173(a)(2). Other requirements to obtain a major NSR permit vary depending on whether it is a PSD or NNSR permit.

[3] 40 CFR 52.21(b)(50). The regulations at 40 CFR 52.21 apply to the federal PSD program. The EPA has other NSR regulations including 40 CFR 51.165, 51.166, and Appendix S of part 51, that contain analogous provisions. This final rule also applies to those analogous provisions as well. However, there are certain modification provisions under Title I, Subpart D of the CAA and the EPA nonattainment NSR regulations that apply to certain nonattainment area classifications. For example, CAA § 182(e)(2) and 40 CFR part 51, Appendix S II.A.5.(v). This final rule does not cover those provisions. We cite to 40 CFR 52.21 for convenience, but the regulatory revisions we are finalizing apply to other regulations as specified in the regulatory text section of this final rule.

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A new stationary source is subject to major NSR requirements if its potential to emit (PTE) a regulated NSR pollutant exceeds statutory emission thresholds.[4] If it exceeds the applicable threshold, the NSR regulations define it as a "major stationary source."[5]

An existing major stationary source triggers major NSR permitting requirements when it undergoes a "major modification." The EPA's implementing regulations for NSR establish a two-step process for determining major NSR applicability for projects at stationary sources. To be subject to major NSR requirements, the project must result in both (1) a significant emissions increase from the project (the determination of which is called "Step 1" of the NSR applicability analysis); and (2) a significant net emissions increase at the stationary source, taking account of emission increases and emission decreases attributable to other projects undertaken at the stationary source within a specific time frame (called "Step 2" of the NSR applicability analysis, or "contemporaneous netting"). For this two-step process, the NSR regulations define what emissions rate constitutes "significant" for each NSR pollutant.[6]

In many cases, these requirements of the major NSR program (or equivalent requirements) are formally adopted by a state or local air agency, and the agency submits a revised state implementation plan (SIP) to the EPA for approval. The EPA's regulations provide for the minimum requirements of these programs. Upon the EPA approving the SIP, the air agency becomes the "reviewing authority" for major NSR permits for sources within its

[4] For PSD, the statute uses the term "major emitting facility" which is defined as a stationary source that emits, or has a PTE, at least 100 tons per year (tpy) if the source is in one of 28 listed source categories—or at least 250 tpy if the source is not—of "any air pollutant." CAA 169(1). For NNSR, the emissions threshold for a major stationary source is 100 tpy, although lower thresholds may apply depending on the degree of the nonattainment problem and the pollutant.
[5] 40 CFR 52.21(b)(1)(i).
[6] 40 CFR 52.21(b)(23).

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boundaries. When a state or local air agency is not the permitting authority, either the EPA issues the major NSR permits or a state or local air agency issues the major NSR permits on behalf of the EPA by way of a delegation agreement. For sources located in Indian country, the EPA is currently the only permitting authority for major NSR. Currently, state and local air agencies issue the vast majority of major NSR permits each year.

New sources and modifications that do not require a major NSR permit may instead require a minor NSR permit prior to construction. Minor NSR permits are almost exclusively issued by state and local air agencies, although the EPA issues minor NSR permits in some areas of Indian country. Minor NSR requirements are approved into a SIP in order to achieve and maintain the NAAQS.[7] The CAA and the EPA's regulations are less prescriptive regarding minimum requirements for minor NSR, thus, air agencies generally have more flexibility in designing their minor NSR programs.

B. Major Modifications Under the NSR Program

In the proposal, the EPA explained that our NSR regulations define a major modification[8] as any physical change or change in the method of operation of an existing major stationary source that would result in a significant emissions increase of a regulated NSR pollutant[9] (as determined in Step 1 of the NSR major modification applicability test) and a significant net emissions increase of that pollutant (as determined in Step 2 of the

[7] CAA section 110(a)(2)(C).
[8] 40 CFR 52.21(b)(2).
[9] "Regulated NSR pollutant" is defined at 40 CFR 52.21(b)(50). A "regulated NSR pollutant" includes any pollutant for which a NAAQS has been promulgated and other pollutants such as sulfuric acid mist and hydrogen sulfide, among others.

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major modification applicability test)[10] from the major stationary source. This two-step applicability test, which has been an element of the NSR programs since the 1980's, was codified by the 2002 NSR Reform Rule[11] to explicitly include the prior EPA practice of looking first at whether any emissions increase that would result from a project[12] by itself is significant before evaluating whether there would be a significant "net emission increase"[13] from the major stationary source. In other words, Step 1 considers the effect of the project alone and Step 2 considers the effect of the project and any *other* emissions changes at the major stationary source that are contemporaneous to the project (*i.e.*, generally within a 5-year period) and creditable.

An emissions increase of a regulated NSR pollutant is considered significant if the emissions increase in Step 1 or 2, would be equal to or greater than any of the pollutant-specific Significant Emissions Rates (SERs) listed under the definition of "significant" in the applicable PSD or NNSR regulations.[14] The SERs in the existing NSR regulations are based on an EPA determination that increases in emissions below these levels are *de*

[10] The NSR major modification applicability test is described in 40 CFR 52.21(a)(2)(iv)(*a*).
[11] In 2002, the EPA issued a final rule that revised the regulations governing the major NSR program. The agency refers generally to this rule as the "NSR Reform Rule." As part of this 2002 rule, the EPA revised the NSR applicability requirements for modifications to allow sources more flexibility to respond to rapidly changing markets and plan for future investments in pollution control and prevention technologies. 67 FR 80186 (December 31, 2002).
[12] 40 CFR 52.21(b)(52). We use the term "project" to mean the physical change or change in method of operation under review, though this can encompass one or more activities at an existing major source. A subsequent section of this rule's preamble discusses how multiple activities should be evaluated to determine whether these activities constitute one project.
[13] 40 CFR 52.21(b)(3).
[14] 40 CFR 52.21(b)(23) defines when emissions of listed pollutants are considered significant under the federal PSD program. These pollutants include, but are not limited to, the following: pollutants for which a NAAQS has been promulgated, fluorides, and sulfuric acid mist.

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minimis and thus need not be subject to major NSR permitting. For those regulated NSR pollutants not specifically listed, *any* increase in emissions is significant.[15] In addition, the procedure for calculating whether a proposed project would result in a significant emissions increase depends upon the type of emissions unit(s)[16] that would be included in the proposed project. The emissions units involved in a project can be new, existing, or a combination of new and existing units (*i.e.*, multiple types of emissions units).[17] For new units,[18] the NSR regulations require the difference in pre- and post-project emissions to be calculated based on the difference between a unit's baseline actual emissions (as applicable to new emissions units)[19] and its potential to emit[20] after the project. For existing units,[21] the NSR regulations require that the difference in pre- and post-project emissions be calculated based on the difference between a unit's baseline actual emissions (as applicable to existing emissions units)[22] and its projected actual emissions[23] after the project. Baseline actual emissions for

[15] 40 CFR 52.21(b)(23)(ii). Per 40 CFR 52.21(b)(23)(iii), *significant* also means any emissions rate or any net emissions increase associated with a major stationary source or major modification, which would construct within 10 kilometers of a Class I area, and have an impact on such area equal to or greater than 1 $\mu g/m^3$, (24-hour average).
[16] 40 CFR 52.21(b)(7). There are two types of emissions units, new and existing. A "replacement unit" as defined in the NSR regulations is an existing emissions unit.
[17] 40 CFR 52.21(a)(2)(iv).
[18] 40 CFR 52.21(b)(7)(i). The NSR regulations define a "new emissions unit" as "any emissions unit that is (or will be) newly constructed and that has existed for less than two years from the date such emission unit first operated."
[19] 40 CFR 52.21(b)(48)(iii).
[20] 40 CFR 52.21(b)(4).
[21] 40 CFR 52.21(b)(7)(ii).
[22] 40 CFR 52.21(b)(48)(i) and (ii).
[23] 40 CFR 52.21(b)(41). A source may elect to use the potential to emit for the emissions unit in lieu of projected actual emissions as provided by 40 CFR 52.21(b)(41)(ii)(*d*).

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new units are based on the units' potential to emit before the project.[24] Potential to emit represents a unit's maximum capacity to emit a pollutant under its physical and operational design. Baseline actual emissions for existing units are determined based on the rate of actual emissions (in tons per year) a unit has emitted in the past. Projected actual emissions for existing units are determined based on the maximum rate of actual emissions (in tons per year) a unit is projected to emit in the future.

Once a source determines that a significant emissions increase would occur in Step 1, then the source may deem the project to be a major modification or perform the Step 2 contemporaneous netting analysis to determine if there would be a significant net emissions increase at the major source and thus be subject to major NSR permitting. [25] A "net

[24] The "baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit's potential to emit." 40 CFR 52.21(b)(48)(iii).

[25] Step 2, which is also known as contemporaneous netting, is voluntary and can add complexity to the NSR major modification applicability process in that it requires the additional accounting of all other increases and decreases in actual emissions that are contemporaneous to the project and creditable. This includes accounting of all creditable increases and decreases in emissions over the five-year period prior to the commence construction date for the project, regardless of whether those increases and decreases were associated with air permitting actions for which records would be readily available. It also requires that the source anticipate and include in the netting analysis any creditable increases or decreases in emissions that may occur after the commence construction date for the project and prior to the date the increase from the project is expected to occur, which can range from months to years. 40 CFR 52.21(b)(3)(i)(*b*). In aggregate, this accounting can span well over five years and involve many emissions units at large, complex sources. Additionally, to be creditable, emissions decreases accounted for in Step 2 must, among other things, be enforceable as a practical matter at and after the time actual construction on the project being evaluated in Step 1 begins, which may require one or more additional permitting actions to establish such enforceable emission limits. 40 CFR 52.21(b)(3)(vi)(*b*). If a project results in a significant emissions increase in Step 1, a source may choose to forego the potentially complex and cumbersome process of conducting a contemporaneous netting analysis and subject itself to major NSR permitting requirements after conducting the Step 1 analysis.

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emissions increase" is defined at 40 CFR 52.21(b)(3) and "means, with respect to any regulated NSR pollutant emitted at a major stationary source, the amount by which the sum of the following exceeds zero: (a) [t]he increase in emissions from a particular physical change or change in the method of operation at a stationary source as calculated pursuant to [40 CFR 52.21](a)(2)(iv); and (b) [a]ny other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable." The Step 2 contemporaneous netting analysis is conducted by adding the emissions increase[26] from the project as determined in Step 1 to all *other* increases and decreases in actual emissions at the major stationary source that are contemporaneous with the project and otherwise creditable.

Emissions increases and decreases are contemporaneous if they occur between "[t]he date 5 years before construction on the particular change commences; and [t]he date that the increase from a particular change occurs."[27] An increase or decrease in actual emissions in Step 2 is creditable only if the EPA Administrator or other reviewing authority has not relied on it in issuing a PSD or NNSR permit for the source and the permit is still in effect at the time the major modification occurs.[28] Furthermore, emissions increases in Step 2 are only creditable if the new level of actual emissions exceeds the old level of actual emissions.[29] Emissions decreases in Step 2, on the other hand, are creditable only to the extent that the

[26] This emissions increase is the aggregate increase in emissions from the project and, thus, it includes any emissions increases and decreases from the individual emissions units that are part of the project.
[27] 40 CFR 52.21(b)(3)(ii). The contemporaneous period could be different from a 5-year time period for states with approved State Implementation Plans.
[28] 40 CFR 52.21(b)(3)(iii)(*a*).
[29] 40 CFR 52.21(b)(3)(v).

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old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions and the decrease in actual emissions is enforceable as a practical matter at and after the time that actual construction of the particular change begins.[30] In nonattainment areas, emissions reductions are also only creditable if they have not been relied upon for demonstrating attainment or reasonable further progress.[31]

A project that results in a significant emissions increase in Step 1 and a significant net emissions increase in Step 2 of the NSR major modification applicability test is a major modification that requires a major NSR permit.

C. Project Emissions Accounting

As we stated in the March 2018 memorandum, in 2017 the EPA "identified certain elements of the NSR regulations and associated EPA policies that have been sources of confusion and uncertainty" for both permitting authorities and stakeholders alike.[32] One such element was "whether emissions decreases from a proposed project at an existing major stationary source may be taken into account under Step 1 of the major modification applicability process in the EPA NSR regulations."[33] Thus, in the memorandum, we communicated that after review of past regulatory interpretations and the existing regulations as whole, we interpret our "current NSR regulations [to] provide that emissions decreases as well as increases are to be

[30] 40 CFR 52.21(b)(3)(vi).
[31] 40 CFR 51.165(a)(1)(vi)(E)(3).
[32] March 2018 Memorandum at 1.
[33] *Id.*

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considered at Step 1 of the NSR applicability process, provided they are part of a single project"[34] in the process known as "project emissions accounting."

A project can involve new, existing, or a combination of new and existing units. Before the March 2018 memorandum, there was uncertainty and confusion on whether both increases and decreases could be considered at Step 1 for all types of emissions units because of a slight variation in the regulatory text used for the NSR major modification applicability test that applies to projects that involve a combination of new and existing units (*i.e.*, hybrid test) as compared to the major modification applicability tests that apply to only new or only existing units. As we explained further in the March 2018 memorandum and in this rule's proposal, the regulatory text for new units and existing units use the phrase "sum of the difference," while the hybrid test used the phrase "sum of the increases." In the March 2018 memorandum, the EPA determined, after a review of past regulatory interpretations and the existing regulations as whole, that the best reading of our regulations is that both increases and decreases in emissions could be accounted for at Step 1 for all three types of emissions units under their respective NSR major modification applicability tests. However, recognizing the uncertainty described previously the proposal included revised regulatory text to clarify the regulations that define the major modification applicability test as it applies to projects involving multiple types of emissions units. [35] The proposed regulatory text made clear that emissions increases and decreases for projects that involve multiple types of emissions units can be considered in the same manner as emissions increases and decreases for projects that only involve new units or only involve existing units in

[34] *Id.*
[35] 40 CFR 52.21(a)(2)(iv)(*f*).

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Step 1 of the NSR major modification applicability test. The regulatory text that governed this hybrid test prior to the finalization of this rule said that "a significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the method specified in [40 CFR 52.21] (a)(2)(iv)(*c*)[36] through (*d*)[37]... as applicable with respect to each emission unit, for each type of emissions unit equals or exceeds the significant amount of that pollutant."[38] Thus, in the proposal, we proposed to revise the term "sum of the emissions increases" to "sum of the difference" to mirror the text in 40 CFR 52.21(a)(2)(iv)(*c*) through (*d*) to help clarify that projects that involve multiple types of emissions units should treat the calculation of the change in emissions from the project in Step 1 of the NSR major modification applicability test in the same way as the calculations for projects that only involve new units or only involve existing units (*i.e.*, considering both emissions increases and decreases from the proposed project in Step 1). We also proposed to clarify that the revised term "sum of the difference" would apply to "all emissions units" instead of "for each emissions unit" to make clear that for projects that involve multiple types of emissions units, the source owner or operator will first calculate the "sum of the difference" for each existing unit and "sum of the difference" for each new unit according to 40 CFR 52.21(a)(2)(iv)(*c*) and (*d*) respectively, and then, the owner or operator would proceed to add the "sum of the difference" from (c) and (d) according to 40 CFR 52.21(a)(2)(iv)(*f*), the hybrid test. In the proposal, we also added regulatory text to clarify that the term "sum of the difference" as used in the referenced

[36] Actual-to-projected-actual applicability test for projects that only involve existing emissions units.
[37] Actual-to-potential test for projects that only involve construction of a new emissions unit(s).
[38] 40 CFR 52.21(a)(2)(iv)(*f*) (2019).

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subparagraphs shall include both increases and decreases in emissions as calculated in accordance with those subparagraphs.

D. Legal Analysis and Policy Rationale

In the March 2018 Memorandum, we explained that "the CAA contains no statutory definition of the term "major modification." The CAA does, however, define the term "modification" as "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted."[39] The major NSR applicability regulations discussed previously reflect an interpretation of the statutory phrase "increases the amount of any air pollutant emitted" that is contained in this definition of "modification" in section 111 of the CAA[40] and as cross referenced in both Part C (PSD) and Part D (NNSR) of Title I of the CAA.[41] The United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) has recognized that the CAA "is silent on how to calculate such 'increases' in emissions."[42] Thus, the question of how to determine whether a physical change or change in the

[39] March 2018 Memorandum at 3. 42 U.S.C. 7411(a)(4); CAA section 111(a)(4). This definition of "modification," originally enacted by Congress in 1970 as part of the New Source Performance Standards (NSPS) program, was incorporated by reference for purposes of the newly enacted PSD and nonattainment programs by the Clean Air Act Amendments of 1977. 42 U.S.C. 7479; CAA section 169(C) ("The term ' construction' when used in connection with any source or facility includes the modification (as defined in section 7411 (a) of this title) of any source or facility."); 42 U.S.C. 7501 (4); CAA section 171 (4) ("The terms 'modifications' and ' modified ' mean the same as the term ' modification' as used in section 7411(a)(4) of this title.").
[40] 42 U.S.C.7411(a)(4).
[41] 42 U.S.C.7479(2)(C); 42 U.S.C.7501(4).
[42] *New York v. EPA*, 413 F.3d 3, 22 (D.C. Cir. 2005) (*New York I*).

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method of operation "increases" emissions is ambiguous.[43] Accordingly, because the statutory text does not itself dictate how to determine whether a physical change or change in the method of operation "increases" emissions, under principles established by the Supreme Court,[44] the "EPA has the authority to choose an interpretation" of the term "increases" in "administering the NSR program and filling in the gaps left by Congress."[45] And in choosing an interpretation of the term "increases" in relation to the administration of the NSR program, "[t]here can be no doubt that the EPA is entitled to balance environmental concerns with economic and administrative concerns, at least to a point."[46]

The EPA believes that allowing for consideration of both emissions increases and decreases from a project is consistent with congressional intent for the PSD and NNSR preconstruction permitting programs to cover existing sources only when they undertake projects which result in a non-*de minimis* increase in emissions.[47] If the full scope of emissions changes from a project were *not* considered in Step 1, the regulations could subject a project to major NSR when the *actual* effect of that project would be to reduce emissions or result in a *de minimis*

[43] *New York v. EPA*, 443 F.3d 880, 888–89 (D.C. Cir. 2006) (*New York II*) ("Congress's use of the word 'increases' necessitated further definition regarding rate and measurement for the term to have any contextual meaning.").
[44] *Chevron U.S.A. v. Natural Resources Defense Council*, 467 U.S. 837, 843 (1984) (Where the "statute is silent or ambiguous with respect to the specific issue, the question for the court is whether the agency's answer is based on a permissible construction of the statute.")
[45] *New York I v. EPA*, 413 F.3d at 23, 24.
[46] *Id.* at 23.
[47] *Alabama Power v. Costle*, 636 F.2d 323, 401 (D.C. Cir. 1979) ("Congress wished to apply the permit process, then, only where industrial changes might increase pollution in an area, not where an existing plant changed its operations in ways that produced no pollution increase."); *Id.* at 360 ("Categorical exemptions may also be permissible as an exercise of agency power, inherent in most statutory schemes, to overlook circumstances that in context may fairly be considered *de minimis*. It is commonplace, of course, that the law does not concern itself with trifling matters, and this principle has often found application in the administrative context.").

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increase in emissions, which would be contrary to congressional intent for this program.[48] The EPA sees little policy support for such an outcome. Allowing the consideration of both increases and decreases in emissions in Step 1 allows sources to undertake projects that may be environmentally beneficial overall and that may be forgone if emissions decreases cannot be considered in Step 1. Therefore, the EPA continues to believe a two-step process—first determining the full scope of emissions changes, both increases and decreases, from the project under consideration and second, considering any increases or decreases from other projects at the source that are contemporaneous and creditable—is a reasonable and allowable interpretation of the phrase "increases the amount of any air pollutant emitted" within the definition of "modification."

Furthermore, the EPA continues to believe this approach represents sound policy to the extent it encourages sources to undertake projects that may result in emissions decreases that might not otherwise occur or could be delayed. As stated in the proposal preamble, various sources have indicated to the EPA that they have either significantly delayed or abandoned

[48] Emissions decreases may also be accounted for in Step 2; however, the text in the NSR regulations reads that such decreases are ones "other" than those associated with the project being evaluated in Step 1. 40 CFR 52.21(b)(3)(i)(*b*). Emissions decreases may also be accounted for in Step 2. However, if the source has had other creditable emissions increases that are contemporaneous with the project and must be accounted for at Step 2, the effect of these creditable emissions increases may be larger than the emissions decreases from the project. In this way, without project emissions accounting, a project that by itself results in a *de minimis* increase or even an overall emissions decrease could be subject to major NSR when emissions increases from other projects are considered in Step 2.

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altogether projects that could have resulted in overall emissions decreases[49] given the complexities that Step 2 contemporaneous netting can entail, and given past EPA statements[50] that emissions decreases could not be accounted for in Step 1. Several commenters on the proposal also provided descriptions of actual projects that produced both increases and decreases in emissions to illustrate the types of projects that may result in overall emissions decreases in Step 1 of the NSR major modification applicability test.[51]

III. Final Action

A. Summary of Final Action

In this action, we are finalizing the proposed clarifications to the Step 1 provisions of the major modification applicability test at 40 CFR 52.21(a)(2)(iv).[52] More specifically, we are finalizing minor revisions to the regulations that apply to projects that involve multiple types of emissions units[53] to state that both emissions increases and decreases can be considered in Step 1 of the NSR major modification applicability test in the same manner as they are considered for

[49] For example, National Mining Association Response to Request for Comments on Regulations Appropriate for Repeal, Replacement, or Modification Pursuant to Executive Order 13777, 82 FR 17793, April 13, 2017, at 3-4, EPA-HQ-2017-0190-37770; Testimony of Paul Noe for American Forest & Paper Association (AF&PA) and American Wood Council (AWC), House Energy & Commerce Committee, Subcommittee on Environment, and Climate Change, Oversight Hearing on "New Source Review Permitting Challenges for Manufacturing and Infrastructure," at 2, 5, 7-8, February 14, 2018; AF&PA and AWC April 25, 2019, Executive Order 12866 meeting materials (EPA-HQ-OAR-2018-0048).

[50] 84 FR 39247-39248 (August 9, 2019). The proposal preamble includes a full description of these past statements.

[51] For example, see comments in the regulatory docket for this action at EPA-HQ-OAR-2018-0048-0056, EPA-HQ-OAR-2018-0048-0072 and EPA-HQ-OAR-2018-0048-0077.

[52] *Supra* n.03.

[53] 40 CFR 52.21(a)(2)(iv)(*f*).

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projects that only involve existing emissions units[54] or only involve new emissions units.[55] These minor revisions include, but are not limited to, changing the term "sum of the emissions increase" to "sum of the difference" in the context of the hybrid test that applies to multiple types of emissions units and adding a provision that specifies that the term "sum of the difference" as used for all types of units (new, existing and the combination of new and existing units) shall include both increases and decreases in emissions as calculated in accordance with those subparagraphs.

The EPA is also concluding that it is appropriate to apply its "project aggregation" interpretation and policy, set forth in the 2018 final action that completed reconsideration of a 2009 action on this topic ("the 2018 final action on project aggregation"),[56] to Step 1 of the NSR major modification applicability test for projects that involve both increases and decreases in emissions. Application of this policy may assist sources that are responsible for determining the scope of a project to make that determination and avoid the over aggregation or under aggregation of activities that could subsequently be considered an effort to circumvent the NSR program. As discussed in the 2018 final action on project aggregation, the "substantially related" test in the project aggregation interpretation and policy calls for sources to aggregate emissions from nominally separate activities when there is an apparent technical or economical interconnection between those activities. This 2018 final action on project aggregation also

[54] 40 CFR 52.21(a)(2)(iv)(*c*).
[55] 40 CFR 52.21(a)(2)(iv)(*d*).
[56] 83 FR 57324 (November 15, 2018). The EPA notes, however, that state and local air agencies with approved SIPs are and were not required to amend their plans to adopt the interpretation that projects should be aggregated when "substantially related."

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includes a rebuttable presumption that activities that occur outside a 3-year period are not related and should not be grouped into one project.

Furthermore, the EPA is concluding that the provisions at 40 CFR 52.21(r)(6) are adequate to ensure sufficient monitoring, recordkeeping and reporting of emissions for projects determined not to trigger major NSR, after considering both emissions increases and decreases from the project in Step 1 of the NSR major modification applicability test. These requirements apply when there is a "reasonable possibility" that the project could still result in a significant emissions increase. Lastly, the EPA is not making the regulatory changes in this final rule mandatory for adoption by state and local air agencies with approved major NSR programs. Thus, state and local air agencies can adopt these changes at their discretion.

B. Comments Received and Basis for Final Action

1. General Comments on the Proposal

The EPA received approximately 36 detailed comments[57] on the project emissions accounting proposal, which included comments from industry and industry associations, state and local air agencies, other governmental agencies, environmental advocacy groups, and a policy advocacy group. The EPA also received several comments from individuals and more than 600 comments on the proposed rule from a mass mailer campaign.

The EPA's responses to these comments are provided in a separate Response to Comments (RTC) document included in the docket for this final action. This final rule preamble addresses the most significant comments received.

[57] A few of the comments received include comments from separate entities that joined efforts to provide comments on the proposal for this final action and thus more than 36 associations, government agencies, groups or industry representatives commented on the proposal.

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2. Revisions to Step 1 of the NSR Major Modification Applicability Test

As we explained in Section II.C. of this final rule preamble, the EPA proposed to revise a portion of the major NSR major modification applicability regulations to provide needed clarity over whether project emissions accounting is allowed for all project categories, including projects that involve multiple types of emissions units. Specifically, the EPA proposed to revise the text "sum of the emissions increase" in 40 CFR 52.21(a)(2)(iv)(*f*) to "sum of the difference," as reflected in subparagraphs 40 CFR 52.21(a)(2)(iv)(*c*)-(*d*), the applicability test that applies to only existing units or only new units respectively, to clarify that both emissions increases and decreases in emissions resulting from a proposed project can be considered in Step 1 of the NSR major modification applicability test.

We also proposed to clarify that the revised term "sum of the difference" would apply to "all emissions units" instead of "for each emissions unit" to make clear that for projects that involve multiple types of emissions units, the source owner or operator will first calculate the "sum of the difference" for each existing unit and "sum of the difference" for each new unit according to 40 CFR 52.21(a)(2)(iv)(*c*) and (*d*) respectively, and then, the owner or operator would proceed to add the "sum of the difference" from (*c*) and (*d*) according to 40 CFR 52.21(a)(2)(iv)(*f*), the hybrid test.

In addition, the EPA proposed to add to the regulation a provision that specifies that the term "sum of the difference," as used in the referenced subparagraphs, shall include both increases and decreases in emissions as calculated in accordance with those subparagraphs. With these proposed revisions, we believe the regulations make clear that accounting for emissions

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decreases in Step 1 of the major modification applicability test is allowed for all projects, including projects that involve multiple types of emissions units.

Several commenters supported the proposal's premise of revising the regulatory text to provide clarity that both emissions increases and decreases can be considered in Step 1 of the NSR major modification applicability test for projects that involve multiple types of emissions units. A few of these commenters also supported the specific regulatory text revisions proposed. The commenters stated that the proposal, if finalized, would improve and streamline the permitting process, provide for the timely issuance of permits, and spark economic growth, while still protecting the environment because sources would be more likely to undertake projects that would reduce emissions if those projects were not subject to the NSR major modification requirements.

The EPA agrees with the commenters who believe that the revisions being finalized in this rule will add clarity to Step 1 of the NSR major modification applicability test and provide a more accurate accounting of a project's actual emissions impact. This clarity and accuracy could potentially incentivize energy efficiency and/or other environmentally beneficial projects, thereby furthering the Congressional purpose of the NSR program which is to ensure environmental protection while allowing for economic growth.[58] We also agree with the commenters who supported the specific regulatory text revisions we proposed that were mentioned previously.

[58] *Wisconsin Elec. Power Co. v. Reilly*, 893 F.2d 901, 909-10 (7th Cir. 1990). ("[The] PSD program "represented a balance between 'the economic interests in permitting capital improvements to continue and the environmental interest in improving air quality.' (quoting *Chevron*, 467 U.S. at 851)).

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On the other hand, several commenters argued that, by allowing sources to take credit for emissions decreases from a project in Step 1, facilities may be able to avoid major NSR permitting requirements including the installation of controls based upon BACT or LAER determinations, leading to an increase in emissions. The commenters stated that the proposed rule, if adopted, would potentially reverse air quality gains that have been accomplished over the last few decades, thereby increasing the likelihood of adverse impacts to human health and the environment. These commenters urged the EPA to withdraw the proposed rule and one commenter also urged the EPA to withdraw the March 13, 2018 Memorandum on the same subject.

These comments were echoed by the mass mailer campaign commenters who added that the proposed rule would have the effect of allowing sources to increase emissions without control requirements, thereby enabling coal-fired power plants to operate longer and emit more pollution, reversing the progress that has been achieved in reducing acid rain in the Adirondacks.

The EPA respectfully disagrees with these commenters, including the mass mailer campaign commenters. First, this rule does not directly pertain to or impact acid rain production in the Adirondacks. Second, we do not have a reason to believe that the clarifications to the NSR regulations reflected in this rule will lead to significant and overall emissions increases as a result of construction at stationary sources. Projects that cause emissions increases are already not subject to major NSR requirements if the increases in emissions are below the SERs, with or without considering the associated emissions decreases in Step 1 of the NSR major modification applicability test. Nothing in this rule alters those requirements. For many projects, when considering both emission increases and decreases in Step 1, the project will likely not result in a

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significant emissions increase and should be treated as *de minimis*. This rule is only a clarification of our existing regulations regarding how to conduct projections of project emissions changes by including emissions increases and decreases in this projection as part of Step 1 of the NSR major modification applicability test for projects that involve multiple types of emissions units to make those requirements consistent with the applicability test for projects that only involve new units or only involve existing units. Those clarifications are based on a logical reading of the statute and consistent with the congressional intent for the NSR program, which is to ensure environmental protection while allowing for economic growth. Finally, even though certain projects may not be subject to the NSR major modification requirements, they may still be subject to the applicable minor NSR program permitting requirements.

These commenters did not provide information that demonstrates that it would always be more environmentally beneficial for each project potentially affected by this rule to proceed through the major NSR permitting process and thereby become subject to the applicable NSR permitting requirements, including the installation of BACT or LAER air pollution control technology. There may be environmental benefits from allowing a source to consider decreases in Step 1 and, therefore, not trigger major NSR based on a more accurate accounting of the emissions from the project. By clarifying that decreases may be considered in Step 1, the rule provides an incentive for sources to design their projects to include emissions decreases and pollution controls.[59] In addition, projects that avoid major NSR because they include emission decreases in their calculation of the proposed project's emissions in Step 1 would not necessarily

[59] By allowing decreases in Step 1, we are incentivizing sources to design their projects to include emissions decreases and controls that may be as stringent or more stringent than the BACT or LAER requirements.

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otherwise trigger major NSR because they may not result in a significant net emissions increase in Step 2. Furthermore, the EPA has been told by stakeholders that some projects may not even move forward if the applicant cannot include emissions decreases in its calculation of the proposed' project emissions in Step 1.

However, quantifying the environmental impacts of this rule, as with any NSR rule, is difficult because NSR permitting actions are case-by-case determinations that vary based on the characteristics of the source of emissions (*e.g.*, location, magnitude of emissions and stack heights), the attainment status of the area, and many other characteristics, including business decisions on whether to proceed with a particular project at a certain point in time. The EPA does not have sufficient permitting data to make this quantification and even if the EPA were to request that information through an Information Collection Request for the entire United States or a subset of states, the permit application data do not include information on many important considerations including, for example, the records of any business decisions on whether to proceed with a particular project. We also do not have access to, nor do we require, reporting of any information regarding decisions made for projects that were not pursued.

Thus, to address this information gap, the EPA requested in its August 2019 proposal any examples of the emissions and cost impacts of considering both emissions increases and decreases in Step 1 of the NSR major modification applicability test. Several commenters answered that information request by providing descriptions of projects that produced both increases and decreases in emissions to illustrate the types of projects that may result in overall

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emissions decreases in Step 1 of the NSR major modification applicability test.[60] Two other commenters provided examples highlighting how finalizing this action would achieve emissions reductions while also reducing the NSR regulatory burden in the electric utility sector.[61] Others provided various comments that suggest that this rule may promote emissions reductions by encouraging industry to seek emissions reduction opportunities in their planning processes that they might otherwise forego if they were subject to the major NSR program. However, the information provided did not fill all the data gaps (as explained previously, these include emissions characteristics, cost impacts, business decisions on whether to proceed with a particular project, etc.), and it also did not show that consideration of emissions decreases in Step 1 would necessarily result in more emissions than would be allowed if major NSR requirements are triggered based on emissions increases alone.

In the face of this uncertainty over whether the clarification reflected in this rule will increase emissions from construction at stationary source of air pollution, we have placed greater importance on ensuring that the NSR regulations are clear, logical, and consistent with Congressional intent. As explained in greater detail in Section III.B.3. of this final rule's preamble and in the Response to Comments document for this action, the EPA views allowing for project emissions accounting to be more consistent with the requirement in the Act that a physical change or change in the method of operation at an existing major stationary source is subject to major NSR if it results in a significant increase in emissions. If project emissions

[60] These comments can be found in Section 4.0 of the Response to Comments document for this action.

[61] These comments can be found in Section 5.0 of the Response to Comments document for this action.

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accounting were not allowed, a project that does not result in an overall significant increase in emissions or that actually decreases emissions into the ambient air could be subject to NSR. The EPA believes that allowing for the consideration of the full effect of a project, including any associated decreases, is consistent with the 2002 NSR Reform Rule and more faithfully implements the intent of Congress for the NSR programs, which is to ensure environmental protection while allowing for economic growth. That is because projects that, in total, would result in insignificant emissions increases or overall emissions reductions might be delayed or foregone due to the potential complexities of undergoing a Step 2 major modification applicability process or requiring a major NSR permit.

3. Legal Rationale

As noted in Background Section II.D. of this rule's preamble, the major NSR applicability regulations reflect an interpretation of the statutory phrase "increases the amount of any air pollutant emitted" contained in the definition of "modification."[62] This definition is cross referenced in both Part C (PSD) and Part D (NNSR) of Title I of the CAA.[63] The D.C. Circuit has recognized that the CAA "is silent on how to calculate such 'increases' in emissions."[64] Thus, the question of how to determine whether a physical change or change in method of operation "increases" emissions is ambiguous.[65] Accordingly, because the statutory text does not itself dictate how to determine whether a physical change or change in the method of operation "increases" emissions, under principles established by the Supreme Court,[66] the "EPA has the

[62] *Supra* n.40.
[63] *Supra* n.41.
[64] *Supra* n.42.
[65] *Supra* n.43.
[66] *Supra* n.44.

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authority to choose an interpretation" of the term "increases" in "administering the NSR program and filling in the gaps left by Congress."[67] And in choosing an interpretation of the term "increases" in relation to the administration of the NSR program,", "[t]here can be no doubt that [the] EPA is entitled to balance environmental concerns with economic and administrative concerns, at least to a point."[68]

After reviewing comments received on the proposal, the EPA continues to believe that when determining whether a physical change or change in the method of operation "increases" emissions, allowing for project emissions accounting at Step 1 of the NSR major modification applicability test is more consistent with the Clean Air Act, the 2002 NSR Reform Rule, and the statutory purpose of the NSR program. Not allowing for project emissions accounting could lead to a project that actually results in a decrease in emissions being subject to the major NSR permitting requirements. The EPA believes this would undermine the congressional intent of the NSR program of ensuring environmental protection while allowing for economic growth because projects that, in total, would result in insignificant emissions increases or overall emissions reductions might be delayed or foregone due to the potential complexities of undergoing a Step 2 contemporaneous netting process or the time and expense of major NSR permitting. The EPA explains this conclusion in more detail in the Response to Comments document for this final action.

Several commenters objected to the proposal, however, claiming that project emissions accounting would create an exemption from NSR such that not every physical change or change

[67] *Supra* n.45.
[68] *Supra* n.46.

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in method of operation would be considered in the NSR major modification applicability determination. These commenters cited to a D.C. Circuit decision[69] to argue that "any" in the statutory phrase "increases the amount of any air pollutant emitted" contained in the definition of "modification means "any" and the EPA was creating a "project exemption," similar to the equipment replacement rule deemed unlawful in that D.C. Circuit decision, by allowing the source to include unrelated decreases in Step 1 to ensure a project did not result in a significant emissions increase.[70]

The EPA does not agree that the proposal was intended to create a "project exemption" because, unlike the equipment replacement rule found to be unlawful in that decision, this rule merely clarifies pre-existing applicability requirements and does not provide an exemption from major NSR. This rule simply conforms the regulatory text for projects that involve multiple types of emissions units with the regulatory text that applies to projects that only involve new units or that only involve existing units, and also expressly articulates a meaning of the term "sum of the difference" that is inherent in the phrase. The EPA has already applied a similar approach following the March 2018 memorandum, and this final rule merely clarifies the regulations.

The EPA also disagrees with commenters that argue that this rule precludes consideration of "any" physical change or change in method of operation under the NSR major modification applicability test. Although we proposed that taking account of emissions decreases at Step 1 did

[69] *New York v. EPA*, 443 F.3d 880 (D.C. Cir. 2006) (*New York II*).
[70] *New York II*, 443 F.3d at 887-8 (by using the word expansive word "any" in describing the emissions-increasing changes that qualify as a "modification" under Clean Air Act § 111(a)(4), Congress precluded the EPA from excluding some such changes from NSR).

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not present any reasonable concerns regarding NSR circumvention[71] under the EPA's project aggregation policy,[72] the EPA recognizes that certain aspects of the proposal could have led to the conclusion that the proposed rule change would allow sources to attempt to avoid NSR by allowing sources to include unrelated emissions decreases as part of the project under consideration. Thus, in response to the concerns raised by these and other commenters, the EPA has determined it is appropriate to limit the scope of emissions decreases that can be considered at Step 1 to only the project under review and to not allow sources to attempt to avoid NSR by expanding the scope of decreases to those that are not truly part of the project. As discussed in more detail in Section III.B.4 of this preamble, the EPA has concluded that it is appropriate to apply its project aggregation policy to both emissions increases and decreases to determine the

[71] 84 FR 39251 (August 9, 2019). ("We do not believe it is necessary to adopt the same criteria that apply for separation of activities (*i.e.*, under aggregation) to the grouping of activities, by considering such grouping to potentially constitute "over aggregation" that, in turn, may constitute NSR circumvention. The circumvention policy speaks to the situation where a source carves up what is plainly a single project into multiple projects, where each of those separate projects may result in emissions increases below the significance threshold but which, if considered collectively as one project, would result in an emissions increase above the threshold. Separate activities that, when considered together, either decrease emissions or result in an increase that is not significant are not in view in the EPA's circumvention policy.")

[72] 84 FR 39250 (August 9, 2019). As explained in more detail in the proposal preamble for this action, the 2018 final action on project aggregation describes the procedure (*i.e.*, the "substantially related" test or "circumvention policy") "for determining the circumstances under which nominally separate activities should reasonably be considered to be a single project." More specifically, the policy calls "for sources and reviewing authorities to aggregate emissions from nominally-separate activities when they are "substantially related." For a project to be substantially related, the "interrelationship and interdependence of the activities [is expected], such that substantially related activities are likely to be jointly planned (*i.e.*, part of the same capital improvement project or engineering study), and occur close in time and at components that are functionally interconnected." In addition, the final "project aggregation" action adds that in general "[to] be 'substantially related,' there should be an apparent interconnection – either technically or economically – between the physical and/or operational changes, or a complementary relationship whereby a change at a plant may exist and operate independently, however its benefit is significantly reduced without the other activity."

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scope of the project in Step 1 of the NSR applicability analysis. Many of the commenters' concerns regarding the review of "any" physical change or change in method of operation can be addressed by rationally defining the scope of a project, consistent with this policy. The application of the "substantially-related" test of the 2018 final action on project aggregation should be sufficient to prevent sources from arbitrarily grouping activities for the sole purpose of avoiding the NSR major modification requirements through project emissions accounting. That is because when applying the "substantially related" test to determine the scope of a project, sources should only aggregate emissions changes when there is an apparent technical or economical interconnection between the physical and operational changes. In addition, sources should include in a common project in Step 1 all activities (and only those activities) that meet this "substantially related" test.

Commenters also argued that the EPA had unlawfully not required that emissions decreases be contemporaneous or enforceable in Step 1 of the NSR major modification applicability test. However, the EPA believes that any emission decreases considered in Step 1 are and will need to be contemporaneous because, the "substantially related" test has a temporal component and, as discussed more in Section III.B.4 of this preamble and in the Response to Comments document for this final action, the decreases must be part of the same project.

Regarding the comments that emissions decreases are required to be enforceable,[73] the commenters correctly pointed to the requirement regarding the enforceability of Step 2 contemporaneous emissions decreases and the EPA is not changing those requirements as part of

[73] In this context, the term enforceable is intended to mean that the projections of a decrease in actual emissions for an existing emissions unit need to be enforceable as a practical matter (*e.g.* accompanied by an emission limit).

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the rule. However, Step 2 contemporaneous netting is a distinct idea from project emissions accounting and parallel requirements are not necessarily warranted when the context is considered. Where a source is using emissions reductions from another project within a 5-year contemporaneous period to "net out" of major NSR permitting, it is important that decreases in emissions from another project that are used for this purpose be enforceable to ensure that the reduction is real and permanent. This is because a project that would result in a significant emissions increase is avoiding major NSR due to unrelated changes made at the facility. Project emissions accounting does not allow emissions reductions from another project to be used to avoid major NSR in this way. Rather, project emissions accounting is part of the process for projecting the actual emissions change at a facility resulting from a single project. In this distinct context, the EPA decided in 2002 against requiring that such a projection be enforceable. Instead, the EPA established recordkeeping and reporting requirements to help enforcement authorities hold sources accountable for their projections when there is a reasonable possibility the project could trigger major NSR. In addition, the NSR regulations provide that "[r]egardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase."[74] Therefore, while the EPA is not requiring *projections* to be enforceable at Step 1 regardless of whether the source owner or operator projected increases or decreases in emissions, the NSR regulations do provide for an overall enforceable limitation on actual emission increases. If any emissions decreases are overstated, or any increases understated, the source may be subject to liability if its actual emissions due to the project exceed *de minimis* thresholds. Moreover, the EPA anticipates that

[74] 40 CFR 52.21(a)(2)(iv)(*b*).

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even if, in accounting for the full impact of a project at Step 1, a source would not be required to obtain a major NSR permit, the vast majority of these projects would still be required to obtain a minor NSR permit under the state minor NSR permit program and the EPA anticipates that the emissions decrease(s) from the project would be documented in the permit record.

The EPA does not believe the policy rationale that the commenters provided for wanting the EPA to require that decreases in Step 1 be enforceable outweighs the EPA's policy rationale for not requiring projected actual emissions increases from a project to be enforceable and for treating emission decreases and increases in the same manner when calculating the proposed project emissions in Step 1.[75] As such, the EPA is not finalizing, as part of this action, a requirement that emissions increases or decreases be enforceable in Step 1 unless required by the applicable regulations.[76] As the EPA explained in the proposal, the EPA intends to treat projected actual emissions used in calculating emissions decreases from a project in the same manner as it does emissions increases since they are both part of the same project. Emission decreases should be considered simply part of the projected emissions for the project, not some discrete change from the project subject to different or additional requirements. A lower projected emission increase at an existing emissions unit involved in a project can have the same numerical effect on the result of the Step 1 applicability calculation by itself as a projected increase combined with a projected emissions decrease at another unit that is involved in the

[75] 84 FR 39251 (August 9, 2019). ("[T]he EPA currently believes that 'the same reasoning that underpinned the 2002 NSR Reform Rule's treatment of projected actual increases applies equally to projected emissions decreases at Step 1.").

[76] For new emissions units (including any units that have been in operation for less than two years), any emissions increases and decreases would be enforceable because the applicability test for new units is the actual-to-potential test. 40 CFR 52.21(a)(2)(iv)(*d*); *id.* 52.21(b)(4); *id.* 52.21(b)(7).

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project. Therefore, we see no reason why enforceability of projected actual emissions should be required in one instance and not the other. Thus, the reasoning the EPA applied when declining to require that projected actual emissions be made enforceable as part of the 2002 NSR Reform rule continues to apply to projected actual emissions that are derived by combining increases and decreases from the same project in accordance with the clarification reflected in this rule.[77] As we explain in more detail in Section III.B 4 of this preamble, requiring that projected actual emissions decreases be enforceable in Step 1 could effectively replace the actual-to-projected-actual[78] applicability test for existing units with an actual-to-potential test[79], or, more accurately, an actual-to-allowable test[80], which would directly conflict with the EPA's reasoning for adopting the actual-to-projected-actual applicability test in 2002. Among other reasons, limiting projected actual emissions to allowable emissions (even if only for emissions decreases) could confiscate unused capacity of the source[81] and in some cases result in the source later

[77] 67 FR 80204 (December 31, 2002). In the 2002 NSR Reform rule, the EPA expressly declined to adopt a requirement under which a source's projected actual emissions would have become an enforceable emission limitation because: (1) "we are concerned that such a requirement may place an unmanageable resource burden on reviewing authorities," and (2) "we also believe that it is not necessary to make… future projections enforceable in order to adequately enforce the major NSR requirements. The Act provides ample authority to enforce the major NSR requirements if… [a] physical or operational change results in a significant net emissions increase at… [a] major stationary source."

[78] The actual-to-projected-actual applicability test for projects that only involve existing emissions units is the test defined in 40 CFR 52.21(a)(2)(iv)(*c*).

[79] The actual-to-potential test for projects that only involve new emission units is the test defined in 40 CFR 52.21(a)(2)(iv)(*d*).

[80] This is because under the approach requiring enforceability of emissions decreases, the projected actual emissions for an emissions unit would become the allowable emissions for that unit. The definition of allowable emissions can be found at 40 CFR 52.21(b)(16).

[81] For example, if a source was required to establish an enforceable emission limit to consider a decrease that is the result of the project, the source may not be able to later increase production or hours of operation, which would otherwise not even be considered a physical change or change in method of operation subject to NSR applicability. 40 CFR 52.21(b)(2)(iii)(*f*).

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retroactively becoming subject to major NSR requirements.[82] The EPA believes such an outcome would be unacceptable.

Another commenter added that the inclusion of emissions decreases in Step 1 in the NSR major modification applicability calculation must be enforceable, otherwise it would render Step 2 of the analysis meaningless. The commenter asserted that this rule would produce an absurd result by eviscerating Step 2's prohibition against crediting unenforceable emissions decreases for the purposes of netting out of NSR requirements.

The EPA disagrees that allowing for the consideration of emission decreases as part of the projected actual emissions from the project in Step 1 would render the contemporaneous netting provisions of the regulations superfluous or lead to absurd results. Allowing emissions decreases from the project under review to be considered in Step 1 does not mean that Step 2 is superfluous. Step 1 is limited to emissions increases and decreases from the *same* project. The source could still only account for emissions decreases from *another* project within the contemporaneous period in Step 2, subject to the other limitations of contemporaneous netting. In addition, the "substantially related" test mentioned previously, and further explained in Section III.B.4. of this preamble, applies to prevent aggregating into a single project those activities that do not represent such project, so decreases from activities that do not meet this test should not be considered in Step 1. Therefore, Step 2 is not superfluous because it clearly still serves a purpose of considering emissions increases and decreases from other projects that are

[82] This is the opposite of the confiscation of unused capacity: if such an allowable emissions limitation was required and is subsequently relaxed to accommodate an unrelated increase in production rate or hours of operation, and that relaxation resulted in the modification becoming major, the source could become subject to major NSR requirements as if construction had not yet commenced. 40 CFR 52.21(r)(4).

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contemporaneous with the proposed project and otherwise creditable. As discussed previously, if decreases from the project could not be considered in Step 1, that could potentially subject a project that decreases emissions overall to the major NSR permitting requirements. In addition, as noted previously, while the EPA is not requiring projections of decreases at Step 1 to be enforceable, the major NSR regulations contain a provision that "[r]egardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase."[83] Therefore, there is an inherent enforceable limitation on increases of actual emissions.

Finally, an additional commenter asserted that the agency's proposal foregoes statutorily specified benefits—avoidance of air quality violations, improved pollution-control technologies, offsetting emission reductions—in a fashion that is incompatible with any lawful exercise of *de minimis* discretion. This contention is countered by other commenters, however, who stated that this final rule is not an exemption from NSR applicability and is instead a clarification of pre-existing regulatory text specifying how NSR applicability is to be determined for projects that involve multiple types of emissions units.

We agree with the latter commenters. The clarification reflected in this rule is not based on inherent *de minimis* exemption authority and does not alter the EPA's determination of the level of emissions that is significant for any pollutant. As stated previously, each physical change or change in method of operation must still be compared to the significance levels to determine whether or not the change results in an emissions increase that is *de minimis*. All this rule does is clarify that, in projecting whether a project will result in a non-*de minimis* increase in actual

[83] 40 CFR 52.21(a)(2)(iv)(*b*).

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emissions, the source can quantify such an increase based on the full scope of the project, including any portions of the project that are projected to decrease actual emissions. The EPA believes that allowing a source to conduct projections of actual emissions in Step 1 for the full scope of the project, including any decreases in emissions caused by the project, is the best reading of CAA § 111(a)(4) because it will ensure that projects that overall decrease emissions or result in a *de minimis* increase in emissions will not be subject to the major NSR program.

4. Defining the Scope of a Project

In the proposal, we said that defining the scope of the project was within the discretion of the source. We also indicated that when a source is defining the scope of the project: (1) separating activities into smaller projects (*i.e.*, under aggregation) to circumvent the NSR major modifications permitting requirements could be prevented by applying the interpretation and policy set forth in the 2018 final action on project aggregation and (2) adding multiple activities into bigger projects (*i.e.*, over aggregation) was not precluded by any prior interpretation or policy.[84] On this latter point, we added that separate activities which, when considered together, either decrease emissions or result in an increase that is not significant were not previously considered as part of the EPA's circumvention policy. However, we requested comment on whether we should instead apply the "substantially related" criteria to prevent over-aggregation in Step 1 and asked what the impact of applying such a standard would be.[85]

[84] As stated previously, the term "project" is defined in our regulations at 40 CFR 52.21(b)(52). In general, we use the term "project" to mean the physical change or change in method of operation under review, though this can encompass one or more activities at an existing major source. On the other hand, the term "project aggregation" used in the agency's 2018 project aggregation interpretation and policy discusses how multiple activities should be evaluated to determine whether these activities constitute one project.

[85] 84 FR 39251 (August 9, 2019).

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Multiple commenters expressed support for the proposed concept that the scope of a project be at the discretion of the source and that the absence of a provision defining the scope of a project does not create an incentive to over-aggregate.[86] Commenters supported this proposed concept on the grounds that this discretion would allow sources to undertake activities that would reduce overall emissions in cases where a project is comprised of multiple emissions units.

Several commenters, however, expressed concerns that the scope of a project to which project emissions accounting is applied should be defined.[87] Otherwise, any ambiguity in defining the scope of the project would constrain a reviewing authority's ability to verify whether the source has reasonably exercised its discretion in applying project emissions accounting to a project. Other commenters added that the lack of criteria for determining the scope of a project would allow sources to circumvent NSR requirements by selectively considering emissions decreases with unrelated and non-contemporaneous increases. To this point, commenters expressed concern that, under the proposed rule, sources would be able to circumvent NSR requirements by finding contemporaneous emission reductions within the facility and considering them to be part of the project, while not incorporating similar contemporaneous emission increases in the scope of the project.

The EPA does not concur with the commenters who stated that circumvention of the NSR permitting requirements is a likely outcome of the proposed rule because, while not previously contemplated by our project aggregation policy, the EPA has concluded after review of the

[86] These comments can be found in Section 5.0 of the Response to Comments document for this action.
[87] These comments can be found in Section 5.0 of the Response to Comments document for this action.

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comments received on the proposal for this action that the "substantially related" test from our 2018 final action on project aggregation interpretation and policy provides the appropriate basis for sources to determine the scope of a project in Step 1 of the NSR applicability analysis. We believe that applying the 2018 final action on project aggregation interpretation and policy in this context alleviates concerns about potential NSR circumvention in Step 1 of the NSR major modification applicability test. The "substantially related" test, which is reflected in the 2018 final action on project aggregation, calls for sources to aggregate emissions from nominally separate activities when there is an apparent technical or economical interconnection between the physical and operational changes. This 2018 final action on project aggregation also includes a policy of applying a rebuttable presumption that project activities that occur outside a 3-year period are not related and should not be grouped into one project. The EPA has observed that "[w]hen activities are undertaken three or more years apart, there is less of a basis that they have a substantial technical or economic relationship because the activities are typically part of entirely different planning and capital funding cycles."[88]

Under this 2018 final action on project aggregation interpretation and policy, sources continue to have discretion in defining the scope of the project based on their business needs, but at the same time should not arbitrarily group project activities for the purpose of avoiding the NSR major modification requirements. Rather, in accordance with the 2018 final action on project aggregation, sources should define a project to include all activities, and only those activities, that meet the "substantially related" test.

[88] 74 FR 2380 (January 15, 2009).

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Other commenters asserted that the EPA failed to address the possibility that facilities could circumvent NSR by proffering in Step 1 an emissions decrease that turns out to be nothing but a temporary reduction, thus avoiding the need to even modify equipment or install a pollution control device. A commenter added that some courts have imposed a statute of limitations that runs 5 years from the date of the modification and that the proposal, in conjunction with those rulings, invited a source to claim unenforceable decreases to avoid NSR, then simply avoid following through once the limitations period has passed.

We disagree with these commenters. The decrease in emissions in Step 1 will be calculated in most cases using the actual-to-projected-actual applicability test, and the projected actual emissions calculation in that test must be based on consideration of all relevant information.[89] If there is a "reasonable possibility" that the project may result in a significant emissions increase, as defined in the regulations at 40 CFR 52.21(r)(6), the source must meet applicable pre- and post-project recordkeeping, monitoring, and reporting requirements that apply for 5 or 10 years following the resumption of regular operation after the project, depending on the nature of the project. As such, the "reasonable possibility" provisions would provide the records necessary for reviewing authorities to ensure that the emissions reductions are not temporary and provide for enforcement of the major NSR program requirements, as necessary. The EPA also believes that the regulatory text at 40 CFR 52.21(a)(2)(iv)(*b*) that states, "[r]egardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase" provides a safeguard that will ensure that the emissions reductions are not temporary or illusory. If a source,

[89] 40 CFR 52.21(b)(41)(ii)(*a*).

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upon resuming regular operation after a project, fails to realize a reduction in emissions that was projected from a particular unit, or if that reduction is less than was projected, such that the overall emissions increase from the project exceeds the applicable significant emissions rates, then the source could be subject to NSR at that time and potentially an enforcement action. While a commenter expressed concern that some sources may claim unenforceable decreases to avoid NSR and then simply avoid following through with those decreases once the statute of limitations period has passed, the EPA views this possibility as remote because of the safeguard at 40 CFR 52.21(a)(2)(iv)(*b*) and the potential for civil, or even criminal, enforcement.[90]

Finally, several commenters questioned the EPA's decision to forgo a requirement that emissions reductions be enforceable and creditable in order to be used in project emissions accounting. These commenters stated that allowing sources to include uncreditable and unenforceable projected project emission decreases with the knowledge that the EPA will not second-guess those projections, referring to the Actual-to-Projected-Actual Applicability Test Memorandum issued by the EPA in December 2017,[91] readily invited NSR circumvention and increased air pollution with no ability for third-party enforcement.

[90] If an activity that was included in an initial projection of actual emissions no longer falls within the scope of the project, the source should reevaluate the projected emissions change of the project without that activity. Therefore, contrary to the commenters concerns, if a source initially includes an activity that decreases emissions in its projection but subsequently decides that that activity is not within the scope of the project, it must redo the project's projected emissions without that emission decreasing activity.

[91] Letter from E. Scott Pruitt, to Regional Administrators, "New Source Review Preconstruction Permitting Requirements; Enforceability and Use of the Actual-to-Projected-Actual Applicability Test in Determining Major Modification Applicability," December 7, 2017 ("December 2017 ATPA Memorandum"), available at: *https://www.epa.gov/sites/production/files/2017-12/documents/nsr_policy_memo.12.7.17.pdf*.

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The EPA disagrees with these commenters. First, as explained in the August 2019 proposal and in the legal rationale section of this final action (Section III.B.3), the EPA intends to treat the calculation of emissions decreases from a proposed project in the same manner as it does emissions increases from the same proposed project (*i.e.*, including emissions increases and decreases in Step 1 because both are necessary to determine the emissions resulting from the project). Second, requiring that projected actual emissions be made enforceable at the time of the project could effectively replace the actual-to-projected-actual applicability test with an actual-to-potential test, or, more accurately, an actual-to-allowable test, which would directly conflict with the EPA's reasoning for adopting the actual-to-projected-actual applicability test in 2002 and with what the EPA believes is the best reading of CAA §111(a)(4). Third, the EPA believes that a requirement that projected actual emissions be made enforceable at the time of the project would effectively confiscate any unused capacity at the effected emissions unit and potentially require that any future project(s) that might increase emissions from that unit trigger major NSR retroactively.[92] In responding to comments on the actual-to-potential methodology in 2002, the EPA noted that the establishment of an enforceable permit limit "may restrict the ability of a source to increase its emissions in association with an increase in production or hours of operation, which when done alone are not normally considered as physical or operational changes."[93] The EPA also stated "[w]e generally agree with commenters who have argued that existing emissions units in general (including replacement and reconstructed units) have ample track record such that the projection of the proposed project emissions alone is sufficiently

[92] 40 CFR 52.21(r)(4).
[93] 2002 NSR Reform Rule Technical Support Document at I-4-7.

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reliable and enforceable and thus the burdens of up-front permit caps on emissions are unnecessary" and "[w]e disagree with the commenters who thought that the 'actual-to-potential' test should be retained because, among other things, the recordkeeping requirements associated with the 'actual-to-projected-actual' test would be burdensome . . . for most sources, the burden of recordkeeping [associated with use of the actual-to-projected-actual applicability test] is substantially less than the present burden of obtaining a permit containing an up-front cap on actual emissions."[94] Thus, consistent with our reasoning in 2002, the EPA does not believe that these outcomes and making emissions reductions enforceable in Step 1 are necessary in order for sources evaluating projects that involve existing emissions units to reasonably determine whether such projects would result in a significant increase in *actual* emissions just because the project includes a calculated decrease in emissions at one or more emissions units.

In any event, the regulations provide that "[r]egardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase."[95] Therefore, the EPA believes the NSR regulations do provide a mechanism for enforcement if a project is erroneously projected not to result in a significant emissions increase. In addition, many, if not most, of emissions decreases that result from a project will be due to the installation of controls or the removal of an emissions unit. The EPA still believes, as it did in 2002, that even if, in accounting for the full impact of a project in Step 1, a source would not be required to obtain a major NSR permit, the large majority of these projects would still be required, as noted earlier, to obtain a minor NSR permit under the state or

[94] *Id.* at I-4-7, 8.
[95] 40 CFR 52.21(a)(2)(iv)(*b*).

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local air agency minor NSR permitting program and, therefore, the project activities and any emissions decrease(s) accounted for would be documented in those permit records.[96] The EPA-approved implementation plans will also still need to include enforceable emission limits and other control measures intended to protect air quality and a program for "regulation of the modification and construction of any stationary source within the areas covered by the plan as necessary to assure that national ambient air quality standards are achieved, including a permit program as required in parts C and D of this subchapter."[97] Nothing in this final rule conflicts with or diminishes these SIP requirements.

Finally, the December 2017 ATPA Memorandum is not within the scope of this rulemaking, nor does it have any bearing on this final rule. The December 2017 ATPA Memorandum communicated how the EPA intends to apply and exercise its enforcement discretion related to certain aspects of the applicability provisions of the NSR regulations. The policy contained in that memorandum does not constitute a rule, regulation, or other legally binding requirement and it does not change or substitute for any law, rule or regulation, or other legally binding requirement. We, therefore, do not agree that this final rule or the December 2017 APTA Memorandum will place any limitations on third-party enforcement of the major NSR program. Nothing in this final rule changes the enforcement provisions available under the CAA to enforce the major NSR permitting requirements nor the ability of third parties to bring

[96] The EPA expects that as part of the minor NSR permitting process, the emissions increases and decreases occuring from the project will be documented either in the permit application, demonstrating the non-applicability of major NSR, or as requirements in the minor NSR permit itself.

[97] 42 U.S.C. 7410(a)(2)(C).

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potential enforcement actions to the EPA's attention if they suspect that a source has avoided the major NSR permitting requirements.

5. Monitoring, Recordkeeping and Reporting of Emissions Decreases in Step 1 of the NSR Major Modification Applicability Test

The provisions of 40 CFR 52.21(r)(6) apply to projects involving existing emissions units at a major stationary source in circumstances where the owner or operator elects to use the actual-to-projected-actual applicability test for calculating projected actual emissions and there is a reasonable possibility (as defined in subparagraph (r)(6)(vi)) that a project that is not part of a major modification may result in a significant emissions increase. When the reasonable possibility criteria in subparagraph (r)(6)(vi) are triggered, specific pre- and post-project recordkeeping, monitoring and reporting requirements in paragraph (r)(6) must be met, depending on the circumstances. Those include the requirement that before beginning actual construction on the project, the owner or operator document and maintain a record including a description of the project, identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project, and a description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant (including certain specified information).

The requirements of 40 CFR 52.21(r)(6) also include pre-project reporting (for electric utility steam generating units) and post-project monitoring and reporting of emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by *any emissions unit identified* in the pre-project record whose emissions could be "affected" by the project. Under these monitoring provisions, sources must calculate and maintain a record of the

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annual emissions, in tons per year on a calendar year basis, for a period of 5- or 10-years following resumption of regular operations after the change, depending on the type of change at the unit(s). Post-project reporting is required for electric utility steam generating units and is triggered when certain specific criteria that are applicable to all other categories of emissions units are met. In accordance with 40 CFR 52.21(r)(7), the information required to be documented and maintained pursuant to paragraph (r)(6) shall be available for review upon a request for inspection by the reviewing authority or the general public. As described in the proposal preamble, the requirements of 40 CFR 52.21(r)(6) apply equally to units with projected increases and projected decreases in emissions, as long as there is a reasonable possibility that the project could result in a significant emissions increase and those units are part of the project (*i.e.*, their emissions "could be affected" by the project.).

Various commenters expressed that considering emissions increases and decreases in Step 1 of the NSR major modification applicability test would not necessitate any additional monitoring, recordkeeping, or reporting requirements to promote NSR compliance because the current requirements under 40 CFR 52.21(*r*)(6) are adequate for this purpose. A couple of these commenters came to this determination because, in the existing rules, the EPA has already determined that sources should not be required to track small projected increases that are well below the relevant significant emissions rates, and there is even less reason to track projected decreases, since the "possibility" of a significant increase is even more remote. Some of these commenters noted that existing monitoring, recordkeeping, and reporting provisions in state and federal laws that cover all NSR-affected "major sources," and particularly the requirements for "…semiannual reporting, compliance reporting and certifications, and periodic emissions

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inventory reporting under Title V permits, are stringent and adequate to assure that NSR violations will not occur as a result" of considering emissions increases and decreases in Step 1. Another commenter added that minor source permitting requirements will often apply to projects that are not subject to major NSR permitting and that the reviewing authority will verify a source's rationale for determining that a project is minor.

Other commenters, however, felt that the "reasonable possibility" provisions of 40 CFR 52.21(r)(6) are insufficient to guard against potential circumvention of NSR requirements. Commenters in this group stated that sources would be able to forgo the reasonable possibility requirements by projecting that an emissions increase will be less than 50 percent of the significant emission increase level. A few commenters added that reliance on the provisions of 40 CFR 52.21(r)(6) would complicate enforcement actions because the calculations sources conduct to comply with these provisions often do not include all emissions units associated with a project, especially affected units that are not modified or constructed under a project. These commenters emphasized that while sources can explain if annual emissions from a project exceed the baseline emissions by an amount greater than the significant emission rate, assessing the validity of such explanations places an undue burden upon the reviewing authority.

Several commenters suggested that the problems related to the lack of monitoring, recordkeeping, and reporting requirements for sources whose emissions do not meet the "reasonable possibility" threshold is compounded by the EPA's decision to not require that emissions decreases considered in Step 1 be enforceable. According to these commenters, sources considering emissions increases and decreases in Step 1 of the NSR major modification applicability test would be able to pair an unenforceable emission decrease with an otherwise

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significant emission increase to avoid NSR, and can then avoid tracking the actual emission increase as a result of the changes by "projecting" that the Step 1 net emissions change would be less than 50 percent of the significant emissions increase level. These commenters asserted that the Administrator's directive that the EPA not question a source's NSR calculations (except in cases of "clear error"), referring to the December 2017 APTA Memorandum, means there is little chance that facilities' calculations will be audited and even less chance that the EPA will be able to check the actual emission increases resulting from changes.

The EPA agrees with the commenters that concluded that the regulations at 40 CFR 52.21(r)(6) are sufficient and appropriate to ensure that adequate records are maintained in circumstances where there is a reasonable possibility, as defined in the regulations, that a project determined not to constitute a major modification could result in a significant emissions increase. Those provisions apply equally to projects that trigger the reasonable possibility criteria, regardless of whether those projects include only increases, or increases and decreases in emissions, consistent with the clarifications in this final rule. We also agree that other records required to be maintained and reported under CAA programs will support compliance with the NSR applicability regulations and enforcement of those regulations as necessary. In imposing reasonable possibility recordkeeping requirements, the EPA "strove for a balance between ease of enforcement and avoidance of requirements that would be unnecessary or unduly burdensome on reviewing authorities or the regulated community."[98] Beyond alleging potential NSR circumvention, the commenters who oppose the use of the reasonable possibility provisions did

[98] 72 FR 72610 (December 21, 2007). The "reasonable possibility" provisions of the existing regulations are currently in litigation. *State of New Jersey v. EPA*, No. 08-1065 (D.C. Cir.).

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not provide any persuasive rationale for treating emissions increases and decreases differently for purposes of tracking emissions under those requirements. Since projected actual emissions must be based on all relevant information, sources may not arbitrarily project emissions below the applicability levels for these recordkeeping, monitoring, and reporting requirements.

We agree that in many or most cases, projects that involve both increases and decreases in emissions in Step 1 that do not trigger the reasonable possibility provisions will be subject to minor NSR permitting requirements. As such, records of the project activities, the emissions increases and any emissions decreases associated with those activities, the applicability test and the corresponding emissions calculations should be available or made available for review as part of the permit application and permit records for the project, which include the permit terms.

The EPA, however, disagrees that the "reasonable possibility" provisions at 40 CFR 52.21(r)(6) are insufficient to guard against NSR circumvention as a result of considering emissions increases and decreases in Step 1 and that reliance on those provisions would complicate enforcement and/or place undue burden on reviewing authorities for the reasons cited. First, as explained in Section III.B.4 of this final rule preamble, applying the EPA's 2018 final action on project aggregation interpretation and policy makes clear that any decreases from activities that are accounted for in Step 1 should be "substantially related" to any increases from activities that are part of the same project, meaning that those decreases in fact result from the project. Second, manipulating NSR major modification applicability calculations to circumvent NSR and/or avoid the "reasonable possibility" requirements in the regulations could subject a source to the NSR requirements, substantial civil penalties, and/or criminal liability. The regulations provide that "[r]egardless of any such preconstruction projections, a major

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modification results if the project causes a significant emissions increase and a significant net emissions increase."[99] Thus, if any emissions decreases are overstated, and/or any increases understated, such that the emissions projection at the time shows a source is not subject to NSR or the reasonable possibility requirements, the source will be subject to NSR if and when the project actually results in a major modification. Finally, and as stated previously, we do not agree that the December 2017 APTA Memorandum will have any effect on third-party enforcement of the major NSR program. Nothing in this final rule changes the enforcement provisions available under the CAA to enforce the major NSR permitting requirements nor the ability of third parties to alert the EPA if they suspect that a source has improperly avoided the major NSR permitting requirements.

Other commenters challenged the EPA's reference to the reasonable possibility standard in the proposal on procedural grounds. These commenters stated that the reasonable possibility provisions are not only insufficient, but that they are "arbitrary and capricious" because the EPA failed in the proposal of this rule to specify how the provisions of 40 CFR 52.21(r)(6) are applicable to the consideration of emissions increases and decreases in Step 1 project emissions accounting. One commenter added that "at the outset, depending on how 'the project' is defined by the source operator, the plain text of [40 CFR 52.21(r)(6)], on its face, does not apply to emissions decreases."

The EPA disagrees with these commenters. The requirements of 40 CFR 52.21(r)(6) apply when there is a reasonable possibility that the project could result in a significant emissions increase and that those units are part of the project (*i.e.*, their emissions "could be

[99] 40 CFR 52.21(a)(2)(iv)(*b*).

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affected" by the project). While practically-speaking this would only apply to a project resulting in an overall increase in emissions because an overall decrease would clearly not have a reasonable possibility of triggering NSR, this does not mean that decreases cannot be considered when determining whether a project would result in an overall increase sufficient to trigger these requirements. When the reasonable possibility criteria in subparagraph (r)(6)(vi) are triggered by an overall increase, specific pre- and post-project recordkeeping, monitoring and reporting requirements in paragraph (r)(6) must be met, as described previously.

Based on the regulations themselves and the comments received, the EPA is concluding that the provisions of 40 CFR 52.21(r)(6) are sufficient for purposes of enforcing the NSR major modification applicability requirements including the clarifying revisions to those applicability requirements in this final rule.

6. Considering Emissions Decreases in Step 1 for Delegated and SIP-Approved Programs

In the proposal, we indicated that if this rule was finalized, any revisions to the regulations at 40 CFR 52.21 would apply to the EPA and reviewing authorities that have been delegated federal authority by the EPA to issue PSD permits on behalf of the EPA (via a delegation agreement with an EPA Regional Office).[100] The EPA also indicated that for state and local air agencies that implement the NSR program through EPA-approved SIPs,[101] the EPA also proposed to revise the regulations for approval of such programs (40 CFR 51.165 and 40 CFR

[100] There are currently 7 states that have full or partial delegation of authority to issue PSD permits on behalf of the EPA.

[101] The applicable regulations for state and local air agencies that implement the NSR program through the EPA-approved SIPs include 40 CFR 51.165(2)(ii)(F) and (G); to 40 CFR 51.166(a)(7)(iv)(*f*) and (g). Any references to SIP-approved plans also refer to the plans submitted by local air agencies to the EPA for approval.

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51.166) to be consistent with the proposed revisions to 40 CFR 52.21(a)(2)(iv).[102] For these SIP-approved programs, the EPA also indicated that if the EPA were to finalize the clarifications being proposed, reviewing authorities may not need to revise their state regulations and submit SIP revisions if the current NSR major modification applicability provisions in those regulations can be interpreted to allow for project emissions accounting or if those state and local air agencies incorporate the federal NSR regulations by reference without a date restriction. Lastly, the EPA mentioned that it was currently aware of a few states and local programs where the applicable SIP-approved regulations expressly preclude project emissions accounting. Thus, we requested comment on whether the EPA should determine that the proposed revisions to 40 CFR 51.165(a)(2)(ii)(F) and (G) and 40 CFR 51.166(a)(7)(iv)(*f*) and (*g*) constitute minimum program elements that must be included in order for state and local agency programs implementing part C or part D to be approvable under the SIP.[103]

Commenters expressed various positions regarding whether the proposed revisions should constitute minimum program elements that must be included for state and local programs implementing parts C or D of Title I of the CAA to be approvable under a SIP.[104] A few commenters stated that this final rule should constitute minimum program elements that must be included in an EPA-approved SIP on the basis that the changes in this final rule are clarifications of the regulations adopted by the 2002 NSR Reform Rule. Another one of these commenters

[102] *Supra* n. 03. As indicated in footnote n. 03, the revisions being finalized in this action also apply to Appendix S of part 51.
[103] Such a determination was made with respect to the NSR regulatory revisions the EPA made in 2002. 67 FR 80240 (December 31, 2002).
[104] A SIP refers to an implementation plan submitted by a State to the EPA for approval. In this preamble, this term also refers to implementation plans submitted by local agencies.

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stated that requiring the proposed rule revisions to be minimum program elements for programs implementing part C or part D to be approvable under a SIP would ensure national consistency.

Various commenters, however, opposed the concept of making project emissions accounting a minimum program element for programs implementing part C or part D to be approvable under a SIP. Some of these commenters noted that under section 116 of the CAA, states can adopt SIP provisions that are more stringent than those required by the EPA's regulations. A couple of commenters added that requiring the implementation of project emissions accounting would run afoul of the sovereign authority of state governments.

After reviewing the comments received on this matter, the EPA has determined that the revisions to the regulations at 40 CFR 52.21 adopted in this final rule apply to the EPA and reviewing authorities that have been delegated federal authority from the EPA to issue major NSR permits on behalf of the EPA.[105] For state and local air agencies that implement the NSR program through EPA-approved SIPs, the EPA agrees with those commenters who argued that section 116 of the CAA allows these states and local air agencies to adopt more stringent SIP emission control requirements than required by the EPA's regulations.[106] Thus, the EPA is concluding that reviewing authorities that do not allow for project emissions accounting have applicability requirements that are at least as stringent as those required by the Act or the EPA's implementing regulations and, therefore, are not required to submit SIP revisions or stringency determinations to the EPA as a result of this action. This is because sources that are not allowed

[105] PSD program provisions have been delegated to reviewing authorities. Reviewing authorities in Indian country can request delegation of the major NA NSR provisions, but to date, none have done so.

[106] *Union Electric v. EPA*, 427 U.S. 246,263-264 (1976).

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to use project emissions accounting may be subject to major NSR even where a more-complete accounting of their emissions (*i.e.*, accounting of both emissions increases and decreases in Step 1 of the NSR major modification applicability test) would reveal that the project produced either an emissions decrease or a *de minimis* increase in emissions.

For SIPs approved under 40 CFR 51.166, the EPA has determined that conforming state/local plan revisions will not be subject to the deadline by which a reviewing authority is typically required to revise its implementation plan in response to amendments to the federal regulations.[107] Similarly, because the EPA views not allowing project emissions accounting to be at least as stringent as the requirements under 40 CFR 51.165, plans already approved under the current version of that section of the CFR will continue to be at least as stringent as the revised regulations and states and local air agencies will not need to submit revisions to already approved plans.[108]

7. Environmental and Economic Impact Considerations of Project Emissions Accounting

Two commenters asserted that the EPA was required to evaluate the environmental impacts of the proposed rule. One of these commenters argued that the EPA's lack of permitting data does not excuse the agency from conducting an analysis of the environmental impacts of the rule and that the EPA must use data from its own records and/or request data from state and local reviewing authorities to conduct such an analysis.

[107] 40 CFR 51.166(a)(6). The EPA's view is that no state is "required to revise its implementation plan by reason of" the amendment to 51.166 reflected in this final rule.
[108] 40 CFR 51.165(a)(1), (a)(2)(ii), and (a)(6) (allowing deviations only when at least as stringent).

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In the proposal preamble we indicated that we are unable at this time to estimate any potential environmental or economic impacts or changes in emissions associated with project emissions accounting because most NSR permits are issued by state and local air agencies and the EPA generally lacks information on the economic and environmental impacts of NSR permits. NSR permitting is a case-by-case process and sources make permitting decisions based on many factors. Furthermore, neither the EPA nor state and local reviewing authorities have access to any records of decisions made by sources which would indicate whether a project was or was not undertaken in view of the unavailability of project emissions accounting. We do not, for example, require the reporting of any information concerning projects that are not pursued. Thus, in the proposal, we asked that commenters provide information on particular examples that could assist the EPA in providing some level of qualitative impacts analysis when finalizing this action.

In response to this solicitation, a few commenters noted that project emissions accounting is consistent with the CAA and with the congressional intent that the PSD and NNSR preconstruction permitting programs only apply when an existing source undertakes a project resulting in a significant increase in emissions. Several commenters, however, indicated that this final rule would result in negative environmental impacts by allowing sources to forgo major NSR permitting and the associated BACT or LAER requirement. Commenters stated that the emissions increases that would result from this final rule would contravene the purpose of the NSR program to require permits where changes at industrial facilities might increase air pollution. Other commenters noted that this final rule may have the potential of reducing overall

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emissions by removing a disincentive for sources seeking to undertake projects that would improve the energy efficiency of their operations.

After consideration of the comments received on this matter, we would like to reiterate that this final rule will not allow projects that themselves result in a significant emissions increase (*i.e.*, an increase greater than *de minimis* levels) and a significant net emissions increase to proceed without obtaining a major NSR permit. Rather, the final rule merely clarifies the NSR major modification applicability test to allow for a more accurate accounting of a project's impacts on air quality to the surrounding area by allowing a source to consider all changes in emissions—both increase and decreases—that result from a project in its calculation of the proposed project emissions. This is consistent, rather than contrary, to the congressional intent for the NSR program. Additionally, despite a commenter's assertion that this rule will allow sources to emit more by circumventing the BACT or LAER requirements, there is no evidence to suggest that the final rule will result in greater overall emissions increases than would otherwise be allowed from projects affected by the rule. For example, as the EPA noted in the proposed rule and as indicated by some commenters, it is equally conceivable that accounting for emissions decreases in Step 1 of the NSR major modification applicability test will incentivize sources to undertake energy efficiency and/or other environmentally beneficial projects that they might otherwise have forgone. In addition, just because a project might result in a significant increase in emissions in Step 1 without the accounting for emissions decreases from the project, does not mean that the project would be subject to the BACT or LAER requirements. Such a project could still result in a net emissions decrease, or a net emissions increase that is not significant and does not trigger the major NSR permitting requirements. It is therefore improper

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to compare the use of project emissions accounting to the application of BACT or LAER. These outcomes are not an either-or proposition for a project that would not result in a significant emissions increase when accounting for decreases but would result in a significant emissions increase when decreases from the project are not considered in Step 1.

Several commenters submitted examples of actual projects that involved emissions decreases that would be more likely to proceed with the availability of project emissions accounting. These examples included replacement projects, projects involving the installation of control equipment, and fuel changes—projects that may result in a reduction of overall emissions but may be forgone if decreases associated with the projects are not considered. For example commenters mentioned that, a source may forgo, the installation of an end-of-life replacement to avoid NSR permitting since the emissions would appear as an emissions increase in Step 1 of the applicability determination even when the replacement would have reduced the potential emissions. While the new unit in general may be larger in capacity, their design and material changes generally entail increased efficiency and lower emissions. Newer units may also generally contain inherent emissions controls (e.g., heaters equipped with low NOx burners) that also lower the source's overall emissions. If the source can count emissions decreases from this project under project emissions accounting, then the source may be more likely to undertake the project, or the source owner might expedite it. However, the project may be foregone if the emission decreases could only be considered as part of a more complex Step 2 contemporaneous netting analysis. Furthermore, commenters noted that proposing a project (e.g. expansion that results in increased tank throughput and cooling capacity) may also include the installation of emissions control equipment such as installing a geodesic dome to an external floating roof tank

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to control volatile organic content (VOC) emissions, retrofitting a cooling water tower with drift eliminators to reduce particulate matter emissions; and/or installing dual-seal pumps to reduce fugitive VOC emissions. If the consideration of emissions decreases as part of project emissions accounting at Step 1 were not available, a project that also involves the installation of emissions control equipment that reduces overall emissions could be foregone due to the complexities of Step 2 contemporaneous netting. Project emissions accounting may also expedite the environmental benefits associated with converting a unit to a lesser-emitting fuel source. For example, when emissions decreases are considered at Step 1, a source owner or operator proposing a project that replaces existing oil-fired boilers with lesser-emitting natural gas boilers might not trigger permitting at Step 1, but it would reduce its overall emissions. If project emissions accounting were not available, the source would likely trigger Step 1 and also undergo the Step 2 analysis to determine if it needs a major modification permit for its proposed project. Under Step 2, the source owner or operator would be required to consider all other contemporaneous emissions increases and decreases from the project, usually within a five-year time period, even though the project itself would have already resulted in a decrease in the actual emissions from the facility. Therefore, a source may decide to forgo transitioning to a lesser-emitting fuel to avoid going through some of the complexities of Step 2 contemporaneous netting or potentially having to receive a major NSR permit for a project that decreases emissions. The Response to Comments document for this final action contains more details about these projects.[109]

[109] These comments can be found in Section 4.0 and 5.0 of the Response to Comments document for this action.

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Based on the information and examples provided, the EPA believes that considering the full scope of the impact of a project ensures that congressional intent for the NSR program, to ensure environmental protection while allowing for economic growth, is met. That is to say, this rule provides more clarity to sources and reviewing authorities applying the NSR applicability test and potentially reduces the permitting burden for sources undertaking economically-beneficial projects that do not produce a greater than *de minimis* increase in emissions. The EPA has provided a more complete discussion of the potential environmental impacts of the rule as well as the difficulties of accurately projecting such impacts in the Environmental Justice Considerations Section of this preamble and the same analysis is provided in the Response to Comments document for this final action.

IV. Environmental Justice Considerations

In the proposal, the EPA stated that we did not believe that the proposed revisions to the NSR major modification applicability regulations would have any effect on environmental justice communities because the EPA's NSR regulations in place since the 2002 NSR Reform Rule was finalized to allow project emissions accounting. As such, the EPA expected no increase in the permitting burden for sources, reviewing authorities or environmental justice communities after finalization of the proposed rule revisions.

Nevertheless, one commenter argued that because the proposed revisions would alter how major modifications are determined under the NSR program, they would result in fewer modifications being subject to major NSR and, therefore, the environmental justice impacts of the rule must be considered accordingly. The commenter added that it is clear that the intention of this rulemaking is to reduce the number of projects that are considered major modifications

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under NSR and this will reduce public health and welfare protection. According to the commenter, this is because fewer facilities will be required to ensure that the changes they are making are protective of ambient air quality and fewer facilities will be required to install pollution controls on new or modified units because their changes will not trigger NSR. Moreover, the commenter stated that environmental justice initiatives stem from the fact that facilities with the worst environmental impact are more likely to be located in areas with higher poverty rates, communities of color, or tribal lands.

We continue to believe that these rule revisions will not impact environmental justice communities in a manner that is different than any impact this rule might have in any other area of the country. As we explained in the proposal preamble, and as stated elsewhere in this preamble, we interpret our regulations to already allow for project emissions accounting even in the absence of this rule. This rulemaking will only serve to provide greater clarity with respect to the major NSR applicability procedures and, thus, will incentivize states to implement project emissions accounting at their discretion. This improved clarity itself confers potential benefits to environmental justice communities by removing a disincentive to the implementation of energy efficiency improvements and other environmentally beneficial projects at industrial sources for sources that might have forgone these projects due to the complexity of the Step 2 contemporaneous netting analysis.

However, to aid stakeholders in their assessment of the potential impacts of this action and to be responsive to the comments received, we did perform a qualitative analysis of a few examples of actual projects that may reduce air emissions due to the availability of project emissions accounting at Step 1 of the NSR major modification applicability test. These examples

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are based on the comments received during the public comment period for this final action, are included as part of the Response to Comments document for this final action and are also summarized in the next few paragraphs of this section of the preamble. This analysis, however, does not provide a qualitative estimate of the potential environmental impacts of accounting for emissions decreases at Step 1 of the NSR major modification applicability test since the commenters did not provide information of any potential emissions increases or decreases that would have occurred in these examples based on the availability of project emissions accounting at Step 1.[110]

Examples of replacement projects: A source may forgo, the installation of an end-of-life replacement to avoid NSR permitting since the emissions would appear as an emissions increase in Step 1 of the applicability determination even when the replacement would have reduced the potential emissions. While the new unit in general may be larger in capacity, their design and material changes generally entail increased efficiency and lower emissions. Newer units may also generally contain inherent emissions controls (e.g., heaters equipped with low NOx burners) that also lower the source's overall emissions. If the source can count emissions decreases from this project under project emissions accounting, then the source may be more likely to undertake the project, or the source owner might expedite it. However, the project may be foregone if the

[110] In its preamble to the proposal, the EPA also highlighted an example of a source that could have saved four additional months of the overall permitting process timeline and $80,000 had it had the opportunity to use project emissions accounting, but there were no emissions implications tied to this example. Thus, it is conceivable that the permitted source was not beholden to BACT/LAER emissions reductions or that the source, had it been able to institute the project earlier, could have instituted emissions reductions to offset any emissions reductions that may have been attributed to the resulting BACT/LAER requirements (assuming such requirements were imposed on the source), while reducing the permitting time burden and avoiding triggering the major NSR permitting requirements.

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emission decreases could only be considered as part of a more complex Step 2 contemporaneous netting analysis.

Examples of projects involving the installation of emissions control equipment: Proposing a project (e.g. expansion that results in increased tank throughput and cooling capacity) may also include the installation of emissions control equipment such as installing a geodesic dome to an external floating roof tank to control volatile organic content (VOC) emissions, retrofitting a cooling water tower with drift eliminators to reduce particulate matter emissions; and/or installing dual-seal pumps to reduce fugitive VOC emissions. If the consideration of emissions decreases as part of project emissions accounting at Step 1 were not available, a project that also involves the installation of emissions control equipment that reduces overall emissions could be foregone due to the complexities of Step 2 contemporaneous netting.

Examples of projects involving fuel changes: Project emissions accounting may also expedite the environmental benefits associated with converting a unit to a lesser-emitting fuel source. For example, when emissions decreases are considered at Step 1, a source owner or operator proposing a project that replaces existing oil-fired boilers with lesser-emitting natural gas boilers might not trigger permitting at Step 1, but it would reduce its overall emissions. If project emissions accounting were not available, the source would likely trigger Step 1 and also undergo the Step 2 analysis to determine if it needs a major modification permit for its proposed project. Under Step 2, the source owner or operator would be required to consider all other contemporaneous emissions increases and decreases from the project, usually within a five-year time period, even though the project itself would have already resulted in a decrease in the actual emissions from the facility. Therefore, a source may decide to forgo transitioning to a lesser-

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emitting fuel to avoid going through some of the complexities of Step 2 contemporaneous netting or potentially having to receive a major NSR permit for a project that decreases emissions.

While this rule may allow projects that produce an overall *de minimis* increase in emissions to forgo the major NSR permitting process, the EPA believes that it is equally conceivable that the rule will create an incentive for sources to adopt emissions-reducing processes and technology (that may represent control beyond what would be required for BACT or LAER) that they would not have otherwise adopted if project emissions accounting were not available. At the very least, the final rule may expedite efficiency-enhancing projects that would have otherwise require a more complex and potentially burdensome Step 2 analysis to determine that the efficiency-enhancing projects would have "netted out" or not be subject to major NSR permitting. These efficiency improvements may have collateral benefits.

The EPA also notes that projects at existing major stationary sources that are determined not to trigger major NSR permitting requirements, will, in many or most cases, be subject to minor NSR permitting requirements, regardless of the accounting procedures used in determining major NSR applicability. Minor NSR permit actions require the opportunity for public comment,[111] which provides an opportunity for stakeholders to raise potential environmental justice concerns based on the characteristics of the project and the location of the project relative to any environmental justice communities within the vicinity of the source. Furthermore, while the EPA shares the commenter's concerns regarding the potential impacts of air pollution on environmental justice communities, the EPA notes that the NSR program is but one of many programs that address air pollution under the Clean Air Act.

[111] 40 CFR 51.161.

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In addition, and as noted elsewhere in this preamble and in the Response to Comments document for this final action, the EPA views project emissions accounting as being fully consistent with the Act and the 2002 NSR Reform Rule. Allowing for project emissions accounting will ensure that a project that itself results in a *de minimis* increase in emissions, or even a decrease in emissions, will not be subject to major NSR. As stated previously, the NSR program was designed to ensure environmental protection while allowing for economic growth by managing increases in emissions from economic development. The EPA believes that project emissions accounting properly balances those interests. In addition, as noted elsewhere, reviewing authorities have the discretion to not allow project emissions accounting and to create or maintain requirements under their SIPs that are at least as stringent as the requirements specified in the EPA's regulations.

Finally, current analytical tools and methods do not allow for a more quantitative analysis of environmental and economic costs associated with the NSR applicability test at this time. However, the EPA will consider whether any newly developed analytical tools or methods would allow for such a quantitative analysis in connection with some future NSR regulatory action.

V. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is a significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review since it raises policy issues arising from the President's priorities. Any changes made in response to OMB recommendations have been documented in the docket as required by section 6(a)(3)(E) of Executive Order 12866.

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B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs

This action is considered an Executive Order 13771 deregulatory action. Before completing this rule, the EPA interpreted its NSR regulations to allow for project emissions accounting. To the extent the clarifications included in this rule influence the actions of sources and reviewing authorities to increase the use of project emissions accounting, this final rule will provide burden reduction.

C. Paperwork Reduction Act (PRA)

This action does not impose any new information collection burden under the PRA. OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control numbers 2060-0003 for the PSD and NNSR permit programs. The burden associated with obtaining an NSR permit for a major stationary source undergoing a major modification is already accounted for under the approved information collection requests.

D. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. Before this rule was finalized, the EPA interpreted its NSR regulations to allow for project emissions accounting and, as such, no increased or decreased burden is expected for sources or reviewing authorities after the finalization of the clarifications included in this rule. Furthermore, the EPA is not making the regulatory changes in this final rule mandatory for adoption and, as such, only major stationary sources located in areas where reviewing authorities decide to newly implement project emissions accounting might see a burden reduction if the

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consideration of emissions increases and decreases in Step 1 does not trigger further permitting requirements that may have otherwise required these major stationary sources to obtain a major NSR permit.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded federal mandate as described in UMRA, 2 U.S.C. 1531-1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local or tribal governments or the private sector.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

G. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. The EPA's NSR major modification applicability regulations in place after the 2002 NSR Reform Rule allow for the consideration of emissions increases and decreases in Step 1 of the NSR major modification applicability test and, as such, the clarifying revisions being proposed in this rule will not have exclusive tribal implications. Furthermore, the EPA is currently the reviewing authority for PSD and NNSR permits issued in tribal lands and, as such, the clarifying revisions

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being proposed will not impose direct burdens on tribal authorities. Thus, Executive Order 13175 does not apply to this action.

H. Executive Order 13045: Protection of Children from Environmental Health and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of "covered regulatory action" in section 2-202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

I. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a "significant energy action" because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. In addition, and before this rule was finalized, the EPA interpreted its NSR regulations to allow for project emissions accounting and, as such, no increased burden is expected for sources or reviewing authorities after the finalization of the clarifications included in this rule. Furthermore, the EPA is not making the regulatory changes in this final rule mandatory for adoption and, as such, only major stationary sources located in areas where state and local reviewing authorities decide to newly implement project emissions accounting might see a burden reduction if the consideration of emissions increases and decreases in Step 1 does not trigger further permitting requirements that may have otherwise required these major stationary sources to obtain a major NSR permit.

J. National Technology Transfer and Advancement Act

This rulemaking does not involve technical standards.

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K. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). Before this rule was finalized, the EPA interpreted its NSR regulations to allow for project emissions accounting and this action only finalized clarifying revisions to the NSR major modification applicability regulations. Further information on the Environmental Justice considerations are included in Section IV of this final action's preamble.

L. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a "major rule" as defined by 5 U.S.C. 804(2).

M. Judicial Review

Under CAA section 307(b)(1), petitions for judicial review of any nationally applicable regulation, or any action the Administrator ''finds and publishes'' as based on a determination of nationwide scope or effect must be filed in the United States Court of Appeals for the District of Columbia Circuit within 60 days of the date the promulgation, approval, or action appears in the *Federal Register*.[112] This action is nationally applicable, as it clarifies the applicability provisions that apply to Step 1 of the NSR major modification applicability test in 40 CFR parts 51.165, 51.166, 52 and Appendix S to Part 51. As a result, petitions for review of this final action

[112] 42 USC 7607(b)(1).

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must be filed in the United States Court of Appeals for the District of Columbia Circuit by **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. Filing a petition for reconsideration by the Administrator of this final action does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review must be filed and shall not postpone the effectiveness of this action.[113]

VI. Statutory Authority

The statutory authority for this action is provided by 42 U.S.C. 7401, *et seq*.

[113] 42 USC 7607(d)(7)(B).

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List of Subjects

40 CFR Part 51

Environmental protection, Air pollution control.

40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference.

.....
Dated:

.....
Andrew Wheeler,
Administrator.

This document is a prepublication version, signed by EPA Administrator, Andrew R. Wheeler on 10/22/2020. We have taken steps to ensure the accuracy of this version, but it is not the official version.

For the reasons stated in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 51–REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

1. The authority citation for part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7401-7671q.

Subpart I—Review of New Sources and Modifications

2. Section 51.165 is amended by revising paragraph (a)(2)(ii)(F) and adding paragraph (G) to read as follows:

§51.165 Permit requirements.

(a) * * *

(2) * * *

(ii) * * *

(F) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference for all emissions units, using the method specified in paragraphs (a)(2)(ii)(C) through (D) of this section as applicable with respect to each emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (a)(1)(x) of this section).

(G) The "sum of the difference" as used in subparagraphs (C), (D) and (F) of this section shall include both increases and decreases in emissions calculated in accordance with those subparagraphs.

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* * * * *

3. Section 51.166 is amended by revising paragraph (a)(7)(iv)(*f*) and adding paragraph (g) to read as follows:

§51.166 Prevention of significant deterioration of air quality.

(a) * * *

(7) * * *

(iv) * * *

(*f*) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference for all emissions units, using the method specified in paragraphs (a)(7)(iv)(*c*) through (*d*) of this section as applicable with respect to each emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(g) The "sum of the difference" as used in subparagraphs (*c*), (*d*) and (*f*) shall include both increases and decreases in emissions calculated in accordance with those subparagraphs.

* * * * *

Subpart CC—Provisions for Implementation of the 2015 Ozone National Ambient Air Quality Standards

4. Appendix S to part 51 is amended by revising section IV.I.1.(v) and adding paragraph (vi) to read as follows:

APPENDIX S TO PART 51—EMISSION OFFSET INTERPRETATIVE RULING

* * * * *

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IV. Sources That Would Locate in a Designated Nonattainment Area

* * * * *

I. *Applicability procedures.*

1. * * *

(v) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference for all emissions units, using the method specified in paragraphs IV.I.1(iii) through (iv) of this Ruling as applicable with respect to each emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph II.A.10 of this Ruling).

(vi) The "sum of the difference" as used in subparagraphs (iii), (iv) and (v) shall include both increases and decreases in emissions calculated in accordance with those subparagraphs.

* * * * *

PART 52–APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

5. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A–General Provisions

6. Section 52.21 is amended by revising paragraph (a)(2)(iv)(*f*) and adding paragraph (g) to read as follows:

§52.21 Prevention of significant deterioration of air quality.

(a) * * *

(2) * * *

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(iv) * * *

(*f*) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference for all emissions units, using the method specified in paragraphs (a)(2)(iv)(*c*) through (*d*) of this section as applicable with respect to each emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(g) The "sum of the difference" as used in subparagraphs (*c*), (*d*) and (*f*) shall include both increases and decreases in emissions calculated in accordance with those subparagraphs.

* * * * *

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C. Petitions for Judicial Review

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by January 25, 2021. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action.

This action, approving the negative declarations submitted by the City of Philadelphia and the District of Columbia, certifying that there are no existing municipal solid waste landfills in the City of Philadelphia or the District of Columbia that are subject to the requirements of 40 CFR part 60 subpart Cf, may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

List of Subjects in 40 CFR Part 62

Environmental protection, Air pollution control, Intergovernmental relations, Reporting andrecordkeeping requirements.

Dated: November 2, 2020.

Cosmo Servidio,

Regional Administrator, Region III.

For the reasons stated in the preamble, the EPA amends 40 CFR part 62 as follows:

PART 62—APPROVAL AND PROMULGATION OF STATE PLANS FOR DESIGNATED FACILITIES AND POLLUTANTS

■ 1. The authority citation for part 62 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart J—District of Columbia

■ 2. Revise § 62.2140 to read as follows:

§ 62.2140 Identification of plan—negative declaration.

Letter from the District of Columbia, Department of Energy and Environment, submitted November 15, 2019, certifying that there are no existing municipal solid waste landfills in the District of Columbia that are subject to 40 CFR part 60, subpart Cf.

Subpart NN—Pennsylvania

■ 3. Revise § 62.9633 to read as follows:

§ 62.9633 Identification of plan—negative declaration.

Letter from the City of Philadelphia, Department of Public Health, submitted March 15, 2018 and amended by email on May 1, 2020, certifying that there are no existing municipal solid waste landfills in the City of Philadelphia that are subject to 40 CFR part 60, subpart Cf.

[FR Doc. 2020–24690 Filed 11–23–20; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 52

[EPA–HQ–OAR–2018–0048; FRL–10016–21–OAR]

RIN 2060–AT89

Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is promulgating revisions to its major New Source Review (NSR) applicability regulations to clarify when the requirement to obtain a major NSR permit applies to a source proposing to undertake a physical change or a change in the method of operation (*i.e.*, a project) under the major NSR preconstruction permitting programs. Under these programs, an existing major stationary source proposing to undertake a project must determine whether that project will constitute a major modification subject to the major NSR preconstruction permitting requirements by following a two-step applicability test. The first step is to determine if the proposed project would result in a ''significant emissions increase'' of a regulated NSR pollutant (Step 1). If the proposed project is determined to result in such an increase, the second step is to determine if the project would also result in a ''significant net emissions increase'' of that pollutant from the source (Step 2). In this action, we are promulgating revisions to our major NSR applicability regulations to clarify that both increases and decreases in emissions resulting from a proposed project can be considered in Step 1 of the major NSR major modification applicability test. We refer to the consideration of emissions increases and decreases in Step 1 as project emissions accounting.

DATES: This final rule is effective on December 24, 2020.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2018–0048. All documents in the docket are listed in the *https://www.regulations.gov* website. Although listed in the index, some information may not be publicly available, *e.g.*, Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy. Publicly available docket materials are available electronically through *https://www.regulations.gov*.

In addition, the EPA has a website for NSR rulemakings at: *https://www.epa.gov/nsr*. The website includes the EPA's proposed and final NSR regulations, as well as guidance documents and technical information related to preconstruction permitting.

FOR FURTHER INFORMATION CONTACT: For further information concerning this action, please contact Jessica Montañez, U.S. EPA, Office of Air Quality Planning and Standards, Air Quality Policy Division, Mail Code C504–03, 109 T.W. Alexander Drive, Research Triangle Park, NC 27709; by telephone at (919) 541–3407 or by email at *montanez.jessica@epa.gov*.

SUPPLEMENTARY INFORMATION: Throughout this document, wherever ''we,'' ''us,'' or ''our'' is used, we mean the EPA and wherever ''reviewing authorities,'' or ''air agencies'' is used, we mean air pollution control agencies.

I. General Information

A. Does this action apply to me?

Entities potentially affected directly by this action include sources in all industry categories. Entities potentially affected directly by this action also include state, local and tribal air pollution control agencies responsible for permitting sources pursuant to the major NSR programs requirements.

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this **Federal Register** document will be posted at *https://www.epa.gov/nsr*.

C. How is this document organized?

The information presented in this document is organized as follows:

I. General Information
A. Does this action apply to me?
B. Where can I get a copy of this document and other related information?
C. How is this document organized?
II. Background
A. The New Source Review Program

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B. Major Modifications Under the NSR Program
C. Project Emissions Accounting
D. Legal Analysis and Policy Rationale
III. Final Action
A. Summary of Final Action
B. Comments Received and Basis for Final Action
1. General Comments on the Proposal
2. Revisions to Step 1 of the NSR Major Modification Applicability Test
3. Legal Rationale
4. Defining the Scope of a Project
5. Monitoring, Recordkeeping and Reporting of Emissions Decreases in Step 1 of the NSR Major Modification Applicability Test
6. Considering Emissions Decreases in Step 1 for Delegated and SIP-Approved Programs
7. Environmental and Economic Impact Considerations of Project Emissions Accounting
IV. Environmental Justice Considerations
V. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs
C. Paperwork Reduction Act (PRA)
D. Regulatory Flexibility Act (RFA)
E. Unfunded Mandates Reform Act (UMRA)
F. Executive Order 13132: Federalism
G. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
H. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks
I. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution or Use
J. National Technology Transfer and Advancement Act (NTTAA)
K. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations
L. Congressional Review Act (CRA)
M. Judicial Review
VI. Statutory Authority

II. Background

On August 9, 2019, the EPA proposed [1] to revise its major NSR applicability regulations to clarify when the requirement to obtain a permit applies to an existing major stationary source proposing to undertake a physical change or change in the method of operation (*i.e.*, project) under the major NSR preconstruction permitting programs. More specifically, the EPA proposed to revise its NSR applicability regulations to make it clear that both emissions increases and decreases that result from a given proposed project are to be considered in Step 1 of the NSR major modification applicability test in a process known as project emissions accounting.

In the subsections that follow, the EPA introduces the NSR program and summarizes information from the proposal, including: (1) What constitutes a major modification under the major NSR programs, (2) the project emissions accounting process and its place in the major modification applicability test, and (3) the legal rationale for the regulatory revisions that were proposed. The history of the EPA's treatment of emissions increases and decreases in Step 1 of the major modification applicability test, including the March 2018 Memorandum titled ''Project Emissions Accounting Under the New Source Review Preconstruction Permitting Program,'' [2] was provided in the notice of proposed rulemaking and will not be restated here. The public comment period for this proposed rule ended on October 8, 2019.

A. The New Source Review Program

As established under the Clean Air Act (CAA), the NSR program is a preconstruction permitting program that requires certain stationary sources of air pollution to obtain permits prior to beginning construction. The NSR permitting program applies to both new construction and to modifications of existing sources, regardless of whether the source is in an area where the national ambient air quality standards (NAAQS) have been exceeded (nonattainment area) or if the source is in an area where the NAAQS have not been exceeded (attainment or unclassifiable area). New construction and modifications that emit ''regulated NSR pollutants'' [3] over certain thresholds are subject to major NSR requirements, while smaller emitting sources and modifications may be subject to minor NSR requirements or be excluded from NSR altogether.

Major NSR permits for sources that are located in attainment or unclassifiable areas are referred to as Prevention of Significant Deterioration (PSD) permits. These permits can also cover pollutants for which there are no NAAQS. Major NSR permits for sources located in nonattainment areas and that emit pollutants above the specified thresholds for which the area is in nonattainment are referred to as nonattainment NSR (NNSR) permits. The pollutant(s) at issue and the air quality designation of the area where the facility is located or proposed to be built determine the specific permitting requirements. The CAA requires sources subject to PSD to meet emission limits based on Best Available Control Technology (BACT) as specified by CAA section 165(a)(4), and sources subject to NNSR to meet Lowest Achievable Emissions Rate (LAER) pursuant to CAA section 173(a)(2). Other requirements to obtain a major NSR permit vary depending on whether it is a PSD or NNSR permit.

A new stationary source is subject to major NSR requirements if its potential to emit (PTE) a regulated NSR pollutant exceeds statutory emission thresholds.[4] If it exceeds the applicable threshold, the NSR regulations define it as a ''major stationary source.'' [5]

An existing major stationary source triggers major NSR permitting requirements when it undergoes a ''major modification.'' The EPA's implementing regulations for NSR establish a two-step process for determining major NSR applicability for projects at stationary sources. To be subject to major NSR requirements, the project must result in both (1) a significant emissions increase from the project (the determination of which is

[1] 84 FR 39244 (August 9, 2019).

[2] Letter from E. Scott Pruitt, to Regional Administrators, ''Project Emissions Accounting Under the New Source Review Preconstruction Permitting Program,'' March 13, 2018 (''March 2018 Memorandum'') available at: *https://www.epa.gov/sites/production/files/2018-03/documents/nsr_memo_03-13-2018.pdf.* As indicated in the proposal, the March 2018 Memorandum explained that ''the EPA interpreted the current NSR regulations as providing that emissions decreases as well as increases are to be considered in Step 1 of the NSR applicability process, where those decreases and increases are part of a single project.'' More specifically, in the March 2018 Memorandum the EPA interpreted the current major NSR regulations to mean that emissions increases and decreases could be considered in Step 1 for projects that involve multiple types of emissions units in the same manner as they are considered for projects that only involve new or only involve existing emissions units.

[3] 40 CFR 52.21(b)(50). The regulations at 40 CFR 52.21 apply to the federal PSD program. The EPA has other NSR regulations including 40 CFR 51.165, 51.166, and Appendix S of part 51, that contain analogous provisions. This final rule also applies to those analogous provisions as well. However, there are certain modification provisions under Title I, Subpart D of the CAA and the EPA nonattainment NSR regulations that apply to certain nonattainment area classifications. For example, CAA section 182(e)(2) and 40 CFR part 51, Appendix S II.A.5.(c). This final rule does not cover those provisions. We cite to 40 CFR 52.21 for convenience, but the regulatory revisions we are finalizing apply to other regulations as specified in the regulatory text section of this final rule.

[4] For PSD, the statute uses the term ''major emitting facility'' which is defined as a stationary source that emits, or has a PTE, at least 100 tons per year (tpy) if the source is in one of 28 listed source categories—or at least 250 tpy if the source is not—of ''any air pollutant.'' CAA section 169(1). For NNSR, the emissions threshold for a major stationary source is 100 tpy, although lower thresholds may apply depending on the degree of the nonattainment problem and the pollutant.

[5] 40 CFR 52.21(b)(1)(i).

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called "Step 1" of the NSR applicability analysis) and (2) a significant net emissions increase at the stationary source, taking account of emission increases and emission decreases attributable to other projects undertaken at the stationary source within a specific time frame (called "Step 2" of the NSR applicability analysis, or "contemporaneous netting"). For this two-step process, the NSR regulations define what emissions rate constitutes "significant" for each NSR pollutant.[6]

In many cases, these requirements of the major NSR program (or equivalent requirements) are formally adopted by a state or local air agency, and the agency submits a revised state implementation plan (SIP) to the EPA for approval. The EPA's regulations provide for the minimum requirements of these programs. Upon the EPA approving the SIP, the air agency becomes the "reviewing authority" for major NSR permits for sources within its boundaries. When a state or local air agency is not the permitting authority, either the EPA issues the major NSR permits or a state or local air agency issues the major NSR permits on behalf of the EPA by way of a delegation agreement. For sources located in Indian country, the EPA is currently the only permitting authority for major NSR. Currently, state and local air agencies issue the vast majority of major NSR permits each year.

New sources and modifications that do not require a major NSR permit may instead require a minor NSR permit prior to construction. Minor NSR permits are almost exclusively issued by state and local air agencies, although the EPA issues minor NSR permits in some areas of Indian country. Minor NSR requirements are approved into a SIP in order to achieve and maintain the NAAQS.[7] The CAA and the EPA's regulations are less prescriptive regarding minimum requirements for minor NSR, thus, air agencies generally have more flexibility in designing their minor NSR programs.

B. Major Modifications Under the NSR Program

In the proposal, the EPA explained that our NSR regulations define a major modification[8] as any physical change or change in the method of operation of an existing major stationary source that would result in a significant emissions increase of a regulated NSR pollutant[9] (as determined in Step 1 of the NSR major modification applicability test) and a significant net emissions increase of that pollutant (as determined in Step 2 of the major modification applicability test)[10] from the major stationary source. This two-step applicability test, which has been an element of the NSR programs since the 1980's, was codified by the 2002 NSR Reform Rule[11] to explicitly include the prior EPA practice of looking first at whether any emissions increase that would result from a project[12] by itself is significant before evaluating whether there would be a significant "net emission increase"[13] from the major stationary source. In other words, Step 1 considers the effect of the project alone and Step 2 considers the effect of the project and any *other* emissions changes at the major stationary source that are contemporaneous to the project (*i.e.*, generally within a 5-year period) and creditable.

An emissions increase of a regulated NSR pollutant is considered significant if the emissions increase in Step 1 or 2, would be equal to or greater than any of the pollutant-specific Significant Emissions Rates (SERs) listed under the definition of "significant" in the applicable PSD or NNSR regulations.[14] The SERs in the existing NSR regulations are based on an EPA determination that increases in emissions below these levels are *de minimis* and thus need not be subject to major NSR permitting. For those regulated NSR pollutants not specifically listed, *any* increase in emissions is significant.[15] In addition, the procedure for calculating whether a proposed project would result in a significant emissions increase depends upon the type of emissions unit(s)[16] that would be included in the proposed project. The emissions units involved in a project can be new, existing, or a combination of new and existing units (*i.e.*, multiple types of emissions units).[17] For new units,[18] the NSR regulations require the difference in pre- and post-project emissions to be calculated based on the difference between a unit's baseline actual emissions (as applicable to new emissions units)[19] and its potential to emit[20] after the project. For existing units,[21] the NSR regulations require that the difference in pre- and post-project emissions be calculated based on the difference between a unit's baseline actual emissions (as applicable to existing emissions units)[22] and its projected actual emissions[23] after the project. Baseline actual emissions for new units are based on the units' potential to emit before the project.[24] Potential to emit represents a unit's maximum capacity to emit a pollutant under its physical and operational design. Baseline actual emissions for existing units are determined based on the rate of actual emissions (in tons per year) a unit has emitted in the past. Projected actual emissions for existing units are determined based on the maximum rate of actual emissions (in tons per year) a unit is projected to emit in the future.

Once a source determines that a significant emissions increase would occur in Step 1, then the source may deem the project to be a major

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[6] 40 CFR 52.21(b)(23).

[7] CAA section 110(a)(2)(C).

[8] 40 CFR 52.21(b)(2).

[9] "Regulated NSR pollutant" is defined at 40 CFR 52.21(b)(50). A "regulated NSR pollutant" includes any pollutant for which a NAAQS has been promulgated and other pollutants such as sulfuric acid mist and hydrogen sulfide, among others.

[10] The NSR major modification applicability test is described in 40 CFR 52.21(a)(2)(iv)(a).

[11] In 2002, the EPA issued a final rule that revised the regulations governing the major NSR program. The agency refers generally to this rule as the "NSR Reform Rule." As part of this 2002 rule, the EPA revised the NSR applicability requirements for modifications to allow sources more flexibility to respond to rapidly changing markets and plan for future investments in pollution control and prevention technologies. 67 FR 80185 (December 31, 2002).

[12] 40 CFR 52.21(b)(52). We use the term "project" to mean the physical change or change in method of operation under review, though this can encompass one or more activities at an existing major source. A subsequent section of this rule's preamble discusses how multiple activities should be evaluated to determine whether these activities constitute one project.

[13] 40 CFR 52.21(b)(3).

[14] 40 CFR 52.21(b)(23) defines when emissions of listed pollutants are considered *significant* under the federal PSD program. These pollutants include, but are not limited to, the following: Pollutants for which a NAAQS has been promulgated, fluorides, and sulfuric acid mist.

[15] 40 CFR 52.21(b)(23)(ii). Per 40 CFR 52.21(b)(23)(ii), *significant* also means any emissions rate or any net emissions increase associated with a major stationary source or major modification, which would construct within 10 kilometers of a Class I area, and have an impact on such area equal to or greater than 1 μg/m^3, (24-hour average).

[16] 40 CFR 52.21(b)(7). There are two types of emissions units, new and existing. A "replacement unit" as defined in the NSR regulations is an existing emissions unit.

[17] 40 CFR 52.21(a)(2)(iv).

[18] 40 CFR 52.21(b)(7)(i). The NSR regulations define a "new emissions unit" as "any emissions unit that is (or will be) newly constructed and that has existed for less than two years from the date such emission unit first operated."

[19] 40 CFR 52.21(b)(48)(iii).

[20] 40 CFR 52.21(b)(4).

[21] 40 CFR 52.21(b)(7)(ii).

[22] 40 CFR 52.21(b)(48)(i) and (ii).

[23] 40 CFR 52.21(b)(41). A source may elect to use the potential to emit for the emissions unit in lieu of projected actual emissions as provided by 40 CFR 52.21(b)(41)(ii)(*d*).

[24] The "baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit's potential to emit." 40 CFR 52.21(b)(48)(iii)

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modification or perform the Step 2 contemporaneous netting analysis to determine if there would be a significant net emissions increase at the major source and thus be subject to major NSR permitting.[25] A net emissions increase means, with respect to any regulated NSR pollutant emitted at a major stationary source, the amount by which the sum of the following exceeds zero: (a) [t]he increase in emissions from a particular physical change or change in the method of operation at a stationary source as calculated pursuant to [40 CFR 52.21](a)(2)(iv); and (b) [a]ny other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable.[26] The Step 2 contemporaneous netting analysis is conducted by adding the emissions increase[27] from the project as determined in Step 1 to all *other* increases and decreases in actual emissions at the major stationary source that are contemporaneous with the project and otherwise creditable.

Emissions increases and decreases are contemporaneous if they occur between ''[t]he date 5 years before construction on the particular change commences; and [t]he date that the increase from a particular change occurs.'' [28] An increase or decrease in actual emissions in Step 2 is creditable only if the EPA Administrator or other reviewing authority has not relied on it in issuing a PSD or NNSR permit for the source and the permit is still in effect at the time the major modification occurs.[29] Furthermore, emissions increases in Step 2 are only creditable if the new level of actual emissions exceeds the old level of actual emissions.[30] Emissions decreases in Step 2, on the other hand, are creditable only to the extent that the old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions and the decrease in actual emissions is enforceable as a practical matter at and after the time that actual construction of the particular change begins.[31] In nonattainment areas, emissions reductions are also only creditable if they have not been relied upon for demonstrating attainment or reasonable further progress.[32]

A project that results in a significant emissions increase in Step 1 and a significant net emissions increase in Step 2 of the NSR major modification applicability test is a major modification that requires a major NSR permit.

C. Project Emissions Accounting

As we stated in the March 2018 Memorandum, in 2017 the EPA ''identified certain elements of the NSR regulations and associated EPA policies that have been sources of confusion and uncertainty'' for both permitting authorities and stakeholders alike.[33] One such element was ''whether emissions decreases from a proposed project at an existing major stationary source may be taken into account under Step 1 of the major modification applicability process in the EPA NSR regulations.'' [34] Thus, in the Memorandum, we communicated that after review of past regulatory interpretations and the existing regulations as whole, we interpret our ''current NSR regulations [to] provide that emissions decreases as well as increases are to be considered at Step 1 of the NSR applicability process, provided they are part of a single project'' [35] in the process known as ''project emissions accounting.''

A project can involve new, existing, or a combination of new and existing units. Before the March 2018 Memorandum, there was uncertainty and confusion on whether both increases and decreases could be considered at Step 1 for all types of emissions units because of a slight variation in the regulatory text used for the NSR major modification applicability test that applies to projects that involve a combination of new and existing units (*i.e.*, hybrid test) as compared to the major modification applicability tests that apply to only new or only existing units. As we explained further in the March 2018 Memorandum and in this rule's proposal, the regulatory text for new units and existing units use the phrase ''sum of the difference,'' while the hybrid test used the phrase ''sum of the increases.'' In the March 2018 Memorandum, the EPA determined, after a review of past regulatory interpretations and the existing regulations as whole, that the best reading of our regulations is that both increases and decreases in emissions could be accounted for at Step 1 for all three types of emissions units under their respective NSR major modification applicability tests. However, recognizing the uncertainty described previously the proposal included revised regulatory text to clarify the regulations that define the major modification applicability test as it applies to projects involving multiple types of emissions units.[36] The proposed regulatory text made clear that emissions increases and decreases for projects that involve multiple types of emissions units can be considered in the same manner as emissions increases and decreases for projects that only involve new units or only involve existing units in Step 1 of the NSR major modification applicability test. The regulatory text that governed this hybrid test prior to the finalization of this rule said that ''a significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the method specified in [40 CFR 52.21](a)(2)(iv)(c)[37] through (*d*)[38] . . . as applicable with respect to each emission unit, for each type of emissions unit equals or exceeds the significant amount

[25] Step 2, which is also known as contemporaneous netting, is voluntary and can add complexity to the NSR major modification applicability process in that it requires the additional accounting of all other increases and decreases in actual emissions that are contemporaneous to the project and creditable. This includes accounting of all creditable increases and decreases in emissions over the five-year period prior to the commence construction date for the project, regardless of whether those increases and decreases were associated with air permitting actions for which records would be readily available. It also requires that the source anticipate and include in the netting analysis any creditable increases or decreases in emissions that may occur after the commence construction date for the project and prior to the date the increase from the project is expected to occur, which can range from months to years. 40 CFR 52.21(b)(3)(ii)(*b*). In aggregate, this accounting can span well over five years and involve many emissions units at large, complex sources. Additionally, to be creditable, emissions decreases accounted for in Step 2 must, among other things, be enforceable as a practical matter at and after the time actual construction on the project being evaluated in Step 1 begins, which may require one or more additional permitting actions to establish such enforceable emission limits. 40 CFR 52.21(b)(3)(iv)(*b*). If a project results in a significant emissions increase in Step 1, a source may choose to forego the potentially complex and cumbersome process of conducting a contemporaneous netting analysis and subject itself to major NSR permitting requirements after conducting the Step 1 analysis.

[26] 40 CFR 52.21(b)(3).

[27] This emissions increase is the aggregate increase in emissions from the project and, thus, it includes any emissions increases and decreases from the individual emissions units that are part of the project.

[28] 40 CFR 52.21(b)(3)(i). The contemporaneous period could be different from a 5-year time period for states with approved State Implementation Plans.

[29] 40 CFR 52.21(b)(3)(ii)(a).

[30] 40 CFR 52.21(b)(3)(iv).

[31] 40 CFR 52.21(b)(3)(vi).

[32] 40 CFR 51.165(a)(1)(v)(C)(*4*).

[33] March 2018 Memorandum at 1.

[34] *Id.*

[35] *Id.*

[36] 40 CFR 52.21(a)(2)(v)(*f*).

[37] Actual-to-projected-actual applicability test for projects that only involve existing emissions units.

[38] Actual-to-potential test for projects that only involve construction of a new emissions unit(s).

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of that pollutant." [39] Thus, in the proposal, we proposed to revise the term "sum of the emissions increases" to "sum of the difference" to mirror the text in 40 CFR 52.21(a)(2)(iv)(*c*) through (*d*) to help clarify that projects that involve multiple types of emissions units should treat the calculation of the change in emissions from the project in Step 1 of the NSR major modification applicability test in the same way as the calculations for projects that only involve new units or only involve existing units (*i.e.*, considering both emissions increases and decreases from the proposed project in Step 1). We also proposed to clarify that the revised term "sum of the difference" would apply to "all emissions units" instead of "for each emissions unit" to make clear that for projects that involve multiple types of emissions units, the source owner or operator will first calculate the "sum of the difference" for each existing unit and "sum of the difference" for each new unit according to 40 CFR 52.21(a)(2)(iv)(*c*) and (*d*) respectively, and then, the owner or operator would proceed to add the "sum of the difference" from (c) and (d) according to 40 CFR 52.21(a)(2)(iv)(*f*), the hybrid test. In the proposal, we also added regulatory text to clarify that the term "sum of the difference" as used in the referenced subparagraphs shall include both increases and decreases in emissions as calculated in accordance with those subparagraphs.

D. Legal Analysis and Policy Rationale

In the March 2018 Memorandum, we explained that "the CAA contains no statutory definition of the term "major modification." The CAA does, however, define the term "modification" as "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." [40] The major NSR applicability regulations discussed previously reflect an interpretation of the statutory phrase "increases the amount of any air pollutant emitted" that is contained in this definition of "modification" in section 111 of the CAA [41] and as cross referenced in both Part C (PSD) and Part D (NNSR) of Title I of the CAA.[42] The United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) has recognized that the CAA "is silent on how to calculate such 'increases' in emissions." [43] Thus, the question of how to determine whether a physical change or change in the method of operation "increases" emissions is ambiguous.[44] Accordingly, because the statutory text does not itself dictate how to determine whether a physical change or change in the method of operation "increases" emissions, under principles established by the Supreme Court,[45] the "EPA has the authority to choose an interpretation" of the term "increases" in "administering the NSR program and filling in the gaps left by Congress." [46] And in choosing an interpretation of the term "increases" in relation to the administration of the NSR program, "[t]here can be no doubt that the EPA is entitled to balance environmental concerns with economic and administrative concerns, at least to a point." [47]

The EPA believes that allowing for consideration of both emissions increases and decreases from a project is consistent with congressional intent for the PSD and NNSR preconstruction permitting programs to cover existing sources only when they undertake projects which result in a non-*de minimis* increase in emissions.[48] If the full scope of emissions changes from a project were *not* considered in Step 1, the regulations could subject a project to major NSR when the *actual* effect of that project would be to reduce emissions or result in a *de minimis* increase in emissions, which would be contrary to congressional intent for this program.[49] The EPA sees little policy support for such an outcome. Allowing the consideration of both increases and decreases in emissions in Step 1 allows sources to undertake projects that may be environmentally beneficial overall and that may be forgone if emissions decreases cannot be considered in Step 1. Therefore, the EPA continues to believe a two-step process—first determining the full scope of emissions changes, both increases and decreases, from the project under consideration and second, considering any increases or decreases from other projects at the source that are contemporaneous and creditable—is a reasonable and allowable interpretation of the phrase "increases the amount of any air pollutant emitted" within the definition of "modification."

Furthermore, the EPA continues to believe this approach represents sound policy to the extent it encourages sources to undertake projects that may result in emissions decreases that might not otherwise occur or could be delayed. As stated in the proposal preamble, various sources have indicated to the EPA that they have either significantly delayed or abandoned altogether projects that could have resulted in overall emissions decreases [50] given the complexities that Step 2 contemporaneous netting can

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[39] 40 CFR 52.21(a)(2)(iv)(*f*) (2019).

[40] March 2018 Memorandum at 3; 42 U.S.C. 7411(a)(4); CAA section 111(a)(4). This definition of "modification," originally enacted by Congress in 1970 as part of the New Source Performance Standards (NSPS) program, was incorporated by reference for purposes of the newly enacted PSD and nonattainment programs by the Clean Air Act Amendments of 1977. 42 U.S.C. 7479; CAA section 169(1)(C) ("The term 'construction' when used in connection with any source or facility includes the modification (as defined in section 7411(a) of this title) of any source or facility."); 42 U.S.C. 7501(4); CAA section 171(4) ("The terms 'modifications' and 'modified' mean the same as the term 'modification' is used in section 7411(a)(4) of this title.").

[41] 42 U.S.C. 7411(a)(4).

[42] 42 U.S.C. 7479(2)(C); 42 U.S.C. 7501(4).

[43] *New York* v. *EPA*, 413 F.3d 3, 22 (D.C. Cir. 2005) (*New York I*).

[44] *New York* v. *EPA*, 443 F.3d 880, 888–89 (D.C. Cir. 2006) (*New York II*) ("Congress's use of the word 'increases' necessitated further definition regarding rate and measurement for the term to have any contextual meaning.").

[45] *Chevron U.S.A.* v. *Natural Resources Defense Council*, 467 U.S. 837, 843 (1984) (Where the "statute is silent or ambiguous with respect to the specific issue, the question for the court is whether the agency's answer is based on a permissible construction of the statute.")

[46] *New York I* v. *EPA*, 413 F.3d at 23, 24.

[47] *Id.* at 23.

[48] *Alabama Power* v. *Costle*, 636 F.2d 323, 401 (D.C. Cir. 1979) ("Congress wished to apply the permit process, then, only where industrial changes might increase pollution in an area, not where an existing plant changed its operations in ways that produced no pollution increase."); *Id.* at 360 ("Categorical exemptions may also be permissible as an exercise of agency power, inherent in most statutory schemes, to overlook circumstances that in context may fairly be considered *de minimis*. It is commonplace, of course, that the law does not concern itself with trifling matters, and this principle has often found application in the administrative context.").

[49] Emissions decreases may also be accounted for in Step 2; however, the text in the NSR regulations reads that such decreases are ones "other" than those associated with the project being evaluated in Step 1. 40 CFR 52.21(b)(3)(i)(*b*). Emissions decreases may also be accounted for in Step 2. However, if the source has had other creditable emissions increases that are contemporaneous with the project and must be accounted for at Step 2, the effect of these creditable emissions increases may be larger than the emissions decreases from the project. In this way, without project emissions accounting, a project that by itself results in a *de minimis* increase or even an overall emissions decrease could be subject to major NSR when emissions increases from other projects are considered in Step 2.

[50] For example, National Mining Association Response to Request for Comments on Regulations Appropriate for Repeal, Replacement, or Modification Pursuant to Executive Order 13777, 82 FR 17793, April 13, 2017, at 3–4, EPA–HQ–2017–0190–37770; Testimony of Paul Noe for American Forest & Paper Association (AF&PA) and American Wood Council (AWC), House Energy & Commerce Committee, Subcommittee on Environment, and Climate Change, Oversight Hearing on "New Source Review Permitting Challenges for Manufacturing and Infrastructure," at 2, 5, 7–8, February 14, 2018; AF&PA and AWC April 25, 2018, Executive Order 12866 meeting materials (EPA–HQ–OAR–2018–0048).

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entail, and given past EPA statements [51] that emissions decreases could not be accounted for in Step 1. Several commenters on the proposal also provided descriptions of actual projects that produced both increases and decreases in emissions to illustrate the types of projects that may result in overall emissions decreases in Step 1 of the NSR major modification applicability test.[52]

III. Final Action

A. Summary of Final Action

In this action, we are finalizing the proposed clarifications to the Step 1 provisions of the major modification applicability test at 40 CFR 52.21(a)(2)(iv).[53] More specifically, we are finalizing minor revisions to the regulations that apply to projects that involve multiple types of emissions units [54] to state that both emissions increases and decreases can be considered in Step 1 of the NSR major modification applicability test in the same manner as they are considered for projects that only involve existing emissions units [55] or only involve new emissions units.[56] These minor revisions include, but are not limited to, changing the term ''sum of the emissions increase'' to ''sum of the difference'' in the context of the hybrid test that applies to multiple types of emissions units and adding a provision that specifies that the term ''sum of the difference'' as used for all types of units (new, existing and the combination of new and existing units) shall include both increases and decreases in emissions as calculated in accordance with those subparagraphs.

The EPA is also concluding that it is appropriate to apply its ''project aggregation'' interpretation and policy, set forth in the 2018 final action that completed reconsideration of a 2009 action on this topic (''the 2018 final action on project aggregation''),[57] to Step 1 of the NSR major modification applicability test for projects that involve both increases and decreases in emissions. Application of this policy may assist sources that are responsible for determining the scope of a project to make that determination and avoid the over aggregation or under aggregation of activities that could subsequently be considered an effort to circumvent the NSR program. As discussed in the 2018 final action on project aggregation, the ''substantially related'' test in the project aggregation interpretation and policy calls for sources to aggregate emissions from nominally separate activities when there is an apparent technical or economical interconnection between those activities. This 2018 final action on project aggregation also includes a rebuttable presumption that activities that occur outside a 3-year period are not related and should not be grouped into one project.

Furthermore, the EPA is concluding that the provisions at 40 CFR 52.21(r)(6) are adequate to ensure sufficient monitoring, recordkeeping and reporting of emissions for projects determined not to trigger major NSR, after considering both emissions increases and decreases from the project in Step 1 of the NSR major modification applicability test. These requirements apply when there is a ''reasonable possibility'' that the project could still result in a significant emissions increase. Lastly, the EPA is not making the regulatory changes in this final rule mandatory for adoption by state and local air agencies with approved major NSR programs. Thus, state and local air agencies can adopt these changes at their discretion.

B. Comments Received and Basis for Final Action

1. General Comments on the Proposal

The EPA received approximately 36 detailed comments [58] on the project emissions accounting proposal, which included comments from industry and industry associations, state and local air agencies, other governmental agencies, environmental advocacy groups, and a policy advocacy group. The EPA also received several comments from individuals and more than 600 comments on the proposed rule from a mass mailer campaign.

The EPA's responses to these comments are provided in a separate Response to Comments (RTC) document included in the docket for this final action. This final rule preamble addresses the most significant comments received.

2. Revisions to Step 1 of the NSR Major Modification Applicability Test

As we explained in Section II.C. of this final rule preamble, the EPA proposed to revise a portion of the major NSR major modification applicability regulations to provide needed clarity over whether project emissions accounting is allowed for all project categories, including projects that involve multiple types of emissions units. Specifically, the EPA proposed to revise the text ''sum of the emissions increase'' in 40 CFR 52.21(a)(2)(iv)(*f*) to ''sum of the difference,'' as reflected in subparagraphs 40 CFR 52.21(a)(2)(iv)(*c*)–(*d*), the applicability test that applies to only existing units or only new units respectively, to clarify that both emissions increases and decreases in emissions resulting from a proposed project can be considered in Step 1 of the NSR major modification applicability test.

We also proposed to clarify that the revised term ''sum of the difference'' would apply to ''all emissions units'' instead of ''for each emissions unit'' to make clear that for projects that involve multiple types of emissions units, the source owner or operator will first calculate the ''sum of the difference'' for each existing unit and ''sum of the difference'' for each new unit according to 40 CFR 52.21(a)(2)(iv)(*c*) and (*d*) respectively, and then, the owner or operator would proceed to add the ''sum of the difference'' from (*c*) and (*d*) according to 40 CFR 52.21(a)(2)(iv)(*f*), the hybrid test.

In addition, the EPA proposed to add to the regulation a provision that specifies that the term ''sum of the difference,'' as used in the referenced subparagraphs, shall include both increases and decreases in emissions as calculated in accordance with those subparagraphs. With these proposed revisions, we believe the regulations make clear that accounting for emissions decreases in Step 1 of the major modification applicability test is allowed for all projects, including projects that involve multiple types of emissions units.

Several commenters supported the proposal's premise of revising the regulatory text to provide clarity that both emissions increases and decreases can be considered in Step 1 of the NSR major modification applicability test for projects that involve multiple types of emissions units. A few of these commenters also supported the specific regulatory text revisions proposed. The commenters stated that the proposal, if

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[51] 84 FR 39244, at 39247–39248 (August 9, 2019). The proposal preamble includes a full description of these past statements.

[52] For example, see comments in the regulatory docket for this action at EPA–HQ–OAR–2018–0048–0056, EPA–HQ–OAR–2018–0048–0072 and EPA–HQ–OAR–2018–0048–0077.

[53] *Supra* n.03.

[54] 40 CFR 52.21(a)(2)(iv)(*f*).

[55] 40 CFR 52.21(a)(2)(iv)(*c*).

[56] 40 CFR 52.21(a)(2)(iv)(*d*).

[57] 83 FR 57324 (November 15, 2018). The EPA notes, however, that state and local air agencies with approved SIPs are and were not required to amend their plans to adopt the interpretation that projects should be aggregated when ''substantially related.''

[58] A few of the comments received include comments from separate entities that joined efforts to provide comments on the proposal for this final action and thus more than 36 associations, government agencies, groups or industry representatives commented on the proposal.

finalized, would improve and streamline the permitting process, provide for the timely issuance of permits, and spark economic growth, while still protecting the environment because sources would be more likely to undertake projects that would reduce emissions if those projects were not subject to the NSR major modification requirements.

The EPA agrees with the commenters who believe that the revisions being finalized in this rule will add clarity to Step 1 of the NSR major modification applicability test and provide a more accurate accounting of a project's actual emissions impact. This clarity and accuracy could potentially incentivize energy efficiency and/or other environmentally beneficial projects, thereby furthering the Congressional purpose of the NSR program which is to ensure environmental protection while allowing for economic growth.[59] We also agree with the commenters who supported the specific regulatory text revisions we proposed that were mentioned previously.

On the other hand, several commenters argued that, by allowing sources to take credit for emissions decreases from a project in Step 1, facilities may be able to avoid major NSR permitting requirements including the installation of controls based upon BACT or LAER determinations, leading to an increase in emissions. The commenters stated that the proposed rule, if adopted, would potentially reverse air quality gains that have been accomplished over the last few decades, thereby increasing the likelihood of adverse impacts to human health and the environment. These commenters urged the EPA to withdraw the proposed rule and one commenter also urged the EPA to withdraw the March 13, 2018 Memorandum on the same subject.

These comments were echoed by the mass mailer campaign commenters who added that the proposed rule would have the effect of allowing sources to increase emissions without control requirements, thereby enabling coal-fired power plants to operate longer and emit more pollution, reversing the progress that has been achieved in reducing acid rain in the Adirondacks.

The EPA respectfully disagrees with these commenters, including the mass mailer campaign commenters. First, this rule does not directly pertain to or impact acid rain production in the Adirondacks. Second, we do not have a reason to believe that the clarifications to the NSR regulations reflected in this rule will lead to significant and overall emissions increases as a result of construction at stationary sources. Projects that cause emissions increases are already not subject to major NSR requirements if the increases in emissions are below the SERs, with or without considering the associated emissions decreases in Step 1 of the NSR major modification applicability test. Nothing in this rule alters those requirements. For many projects, when considering both emission increases and decreases in Step 1, the project will likely not result in a significant emissions increase and should be treated as *de minimis*. This rule is only a clarification of our existing regulations regarding how to conduct projections of project emissions changes by including emissions increases and decreases in this projection as part of Step 1 of the NSR major modification applicability test for projects that involve multiple types of emissions units to make those requirements consistent with the applicability test for projects that only involve new units or only involve existing units. Those clarifications are based on a logical reading of the statute and consistent with the congressional intent for the NSR program, which is to ensure environmental protection while allowing for economic growth. Finally, even though certain projects may not be subject to the NSR major modification requirements, they may still be subject to the applicable minor NSR program permitting requirements.

These commenters did not provide information that demonstrates that it would always be more environmentally beneficial for each project potentially affected by this rule to proceed through the major NSR permitting process and thereby become subject to the applicable NSR permitting requirements, including the installation of BACT or LAER air pollution control technology. There may be environmental benefits from allowing a source to consider decreases in Step 1 and, therefore, not trigger major NSR based on a more accurate accounting of the emissions from the project. By clarifying that decreases may be considered in Step 1, the rule provides an incentive for sources to design their projects to include emissions decreases and pollution controls.[60] In addition, projects that avoid major NSR because they include emission decreases in their calculation of the proposed project's emissions in Step 1 would not necessarily otherwise trigger major NSR because they may not result in a significant net emissions increase in Step 2. Furthermore, the EPA has been told by stakeholders that some projects may not even move forward if the applicant cannot include emissions decreases in its calculation of the proposed' project emissions in Step 1.

However, quantifying the environmental impacts of this rule, as with any NSR rule, is difficult because NSR permitting actions are case-by-case determinations that vary based on the characteristics of the source of emissions (e.g., location, magnitude of emissions and stack heights), the attainment status of the area, and many other characteristics, including business decisions on whether to proceed with a particular project at a certain point in time. The EPA does not have sufficient permitting data to make this quantification and even if the EPA were to request that information through an Information Collection Request for the entire United States or a subset of states, the permit application data do not include information on many important considerations including, for example, the records of any business decisions on whether to proceed with a particular project. We also do not have access to, nor do we require, reporting of any information regarding decisions made for projects that were not pursued.

Thus, to address this information gap, the EPA requested in its August 2019 proposal any examples of the emissions and cost impacts of considering both emissions increases and decreases in Step 1 of the NSR major modification applicability test. Several commenters answered that information request by providing descriptions of projects that produced both increases and decreases in emissions to illustrate the types of projects that may result in overall emissions decreases in Step 1 of the NSR major modification applicability test.[61] Two other commenters provided examples highlighting how finalizing this action would achieve emissions reductions while also reducing the NSR regulatory burden in the electric utility sector.[62] Others provided various comments that suggest that this rule

[59] *Wisconsin Elec. Power Co.* v. *Reilly*, 893 F.2d 901, 909–10 (7th Cir. 1990). ("[The] PSD program "represented a balance between 'the economic interests in permitting capital improvements to continue and the environmental interest in improving air quality.' (quoting *Chevron*, 467 U.S. at 851)).

[60] By allowing decreases in Step 1, we are incentivizing sources to design their projects to include emissions decreases and controls that may be as stringent or more stringent than the BACT or LAER requirements.

[61] These comments can be found in Section 4.0 of the Response to Comments document for this action.

[62] These comments can be found in Section 5.0 of the Response to Comments document for this action.

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may promote emissions reductions by encouraging industry to seek emissions reduction opportunities in their planning processes that they might otherwise forego if they were subject to the major NSR program. However, the information provided did not fill all the data gaps (as explained previously, these include emissions characteristics, cost impacts, business decisions on whether to proceed with a particular project, etc.), and it also did not show that consideration of emissions decreases in Step 1 would necessarily result in more emissions than would be allowed if major NSR requirements are triggered based on emissions increases alone.

In the face of this uncertainty over whether the clarification reflected in this rule will increase emissions from construction at stationary source of air pollution, we have placed greater importance on ensuring that the NSR regulations are clear, logical, and consistent with Congressional intent. As explained in greater detail in Section III.B.3. of this final rule's preamble and in the Response to Comments document for this action, the EPA views allowing for project emissions accounting to be more consistent with the requirement in the Act that a physical change or change in the method of operation at an existing major stationary source is subject to major NSR if it results in a significant increase in emissions. If project emissions accounting were not allowed, a project that does not result in an overall significant increase in emissions or that actually decreases emissions into the ambient air could be subject to NSR. The EPA believes that allowing for the consideration of the full effect of a project, including any associated decreases, is consistent with the 2002 NSR Reform Rule and more faithfully implements the intent of Congress for the NSR programs, which is to ensure environmental protection while allowing for economic growth. That is because projects that, in total, would result in insignificant emissions increases or overall emissions reductions might be delayed or foregone due to the potential complexities of undergoing a Step 2 major modification applicability process or requiring a major NSR permit.

3. Legal Rationale

As noted in Background Section II.D. of this rule's preamble, the major NSR applicability regulations reflect an interpretation of the statutory phrase "increases the amount of any air pollutant emitted" contained in the definition of "modification."[63] This definition is cross referenced in both Part C (PSD) and Part D (NNSR) of Title I of the CAA.[64] The D.C. Circuit has recognized that the CAA "is silent on how to calculate such 'increases' in emissions."[65] Thus, the question of how to determine whether a physical change or change in method of operation "increases" emissions is ambiguous.[66] Accordingly, because the statutory text does not itself dictate how to determine whether a physical change or change in the method of operation "increases" emissions, under principles established by the Supreme Court,[67] the "EPA has the authority to choose an interpretation" of the term "increases" in "administering the NSR program and filling in the gaps left by Congress."[68] And in choosing an interpretation of the term "increases" in relation to the administration of the NSR program,". "[t]here can be no doubt that [the] EPA is entitled to balance environmental concerns with economic and administrative concerns, at least to a point."[69]

After reviewing comments received on the proposal, the EPA continues to believe that when determining whether a physical change or change in the method of operation "increases" emissions, allowing for project emissions accounting at Step 1 of the NSR major modification applicability test is more consistent with the Clean Air Act, the 2002 NSR Reform Rule, and the statutory purpose of the NSR program. Not allowing for project emissions accounting could lead to a project that actually results in a decrease in emissions being subject to the major NSR permitting requirements. The EPA believes this would undermine the congressional intent of the NSR program of ensuring environmental protection while allowing for economic growth because projects that, in total, would result in insignificant emissions increases or overall emissions reductions might be delayed or foregone due to the potential complexities of undergoing a Step 2 contemporaneous netting process or the time and expense of major NSR permitting. The EPA explains this conclusion in more detail in the Response to Comments document for this final action.

Several commenters objected to the proposal, however, claiming that project emissions accounting would create an exemption from NSR such that not every physical change or change in method of operation would be considered in the NSR major modification applicability determination. These commenters cited to a D.C. Circuit decision[70] to argue that "any" in the statutory phrase "increases the amount of any air pollutant emitted" contained in the definition of "modification means "any" and the EPA was creating a "project exemption," similar to the equipment replacement rule deemed unlawful in that D.C. Circuit decision, by allowing the source to include unrelated decreases in Step 1 to ensure a project did not result in a significant emissions increase.[71]

The EPA does not agree that the proposal was intended to create a "project exemption" because, unlike the equipment replacement rule found to be unlawful in that decision, this rule merely clarifies pre-existing applicability requirements and does not provide an exemption from major NSR. This rule simply conforms the regulatory text for projects that involve multiple types of emissions units with the regulatory text that applies to projects that only involve new units or that only involve existing units, and also expressly articulates a meaning of the term "sum of the difference" that is inherent in the phrase. The EPA has already applied a similar approach following the March 2018 Memorandum, and this final rule merely clarifies the regulations.

The EPA also disagrees with commenters that argue that this rule precludes consideration of "any" physical change or change in method of operation under the NSR major modification applicability test. Although we proposed that taking account of emissions decreases at Step 1 did not present any reasonable concerns regarding NSR circumvention[72] under the EPA's

[63] *Supra* n.41.
[64] *Supra* n.42.
[65] *Supra* n.43.
[66] *Supra* n.44.
[67] *Supra* n.45.
[68] *Supra* n.46.
[69] *Supra* n.47.

[70] *New York v. EPA*, 443 F.3d 880 (D.C. Cir. 2006) (*New York II*).

[71] *New York II*, 443 F.3d at 887–8 (by using the word expansive word "any" in describing the emissions-increasing changes that qualify as a "modification" under Clean Air Act section 111(a)(4), Congress precluded the EPA from excluding some such changes from NSR).

[72] 84 FR 39244, at 39251 (August 9, 2019). ("We do not believe it is necessary to adopt the same criteria that apply for separation of activities (*i.e.*, under aggregation) to the grouping of activities, by considering such grouping to potentially constitute "over aggregation" that, in turn, may constitute NSR circumvention. The circumvention policy speaks to the situation where a source carves up what is plainly a single project into multiple projects, where each of those separate projects may

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project aggregation policy,[73] the EPA recognizes that certain aspects of the proposal could have led to the conclusion that the proposed rule change would allow sources to attempt to avoid NSR by allowing sources to include unrelated emissions decreases as part of the project under consideration. Thus, in response to the concerns raised by these and other commenters, the EPA has determined it is appropriate to limit the scope of emissions decreases that can be considered at Step 1 to only the project under review and to not allow sources to attempt to avoid NSR by expanding the scope of decreases to those that are not truly part of the project. As discussed in more detail in Section III.B.4 of this preamble, the EPA has concluded that it is appropriate to apply its project aggregation policy to both emissions increases and decreases to determine the scope of the project in Step 1 of the NSR applicability analysis. Many of the commenters' concerns regarding the review of ''any'' physical change or change in method of operation can be addressed by rationally defining the scope of a project, consistent with this policy. The application of the ''substantially-related'' test of the 2018 final action on project aggregation should be sufficient to prevent sources from arbitrarily grouping activities for the sole purpose of avoiding the NSR major modification requirements through project emissions accounting. That is because when applying the ''substantially related'' test to determine the scope of a project, sources should only aggregate emissions changes when there is an apparent technical or economical interconnection between the physical and operational changes. In addition, sources should include in a common project in Step 1 all activities (and only those activities) that meet this ''substantially related'' test.

Commenters also argued that the EPA had unlawfully not required that emissions decreases be contemporaneous or enforceable in Step 1 of the NSR major modification applicability test. However, the EPA believes that any emission decreases considered in Step 1 are and will need to be contemporaneous because, the ''substantially related'' test has a temporal component and, as discussed more in Section III.B.4 of this preamble and in the Response to Comments document for this final action, the decreases must be part of the same project.

Regarding the comments that emissions decreases are required to be enforceable,[74] the commenters correctly pointed to the requirement regarding the enforceability of Step 2 contemporaneous emissions decreases and the EPA is not changing those requirements as part of the rule. However, Step 2 contemporaneous netting is a distinct idea from project emissions accounting and parallel requirements are not necessarily warranted when the context is considered. Where a source is using emissions reductions from another project within a 5-year contemporaneous period to ''net out'' of major NSR permitting, it is important that decreases in emissions from another project that are used for this purpose be enforceable to ensure that the reduction is real and permanent. This is because a project that would result in a significant emissions increase is avoiding major NSR due to unrelated changes made at the facility. Project emissions accounting does not allow emissions reductions from another project to be used to avoid major NSR in this way. Rather, project emissions accounting is part of the process for projecting the actual emissions change at a facility resulting from a single project. In this distinct context, the EPA decided in 2002 against requiring that such a projection be enforceable. Instead, the EPA established recordkeeping and reporting requirements to help enforcement authorities hold sources accountable for their projections when there is a reasonable possibility the project could trigger major NSR. In addition, the NSR regulations provide that ''[r]egardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.'' [75] Therefore, while the EPA is not requiring *projections* to be enforceable at Step 1 regardless of whether the source owner or operator projected increases or decreases in emissions, the NSR regulations do provide for an overall enforceable limitation on actual emission increases. If any emissions decreases are overstated, or any increases understated, the source may be subject to liability if its actual emissions due to the project exceed *de minimis* thresholds. Moreover, the EPA anticipates that even if, in accounting for the full impact of a project at Step 1, a source would not be required to obtain a major NSR permit, the vast majority of those projects would still be required to obtain a minor NSR permit under the state minor NSR permit program and the EPA anticipates that the emissions decrease(s) from the project would be documented in the permit record.

The EPA does not believe the policy rationale that the commenters provided for wanting the EPA to require that decreases in Step 1 be enforceable outweighs the EPA's policy rationale for not requiring projected actual emissions increases from a project to be enforceable and for treating emission decreases and increases in the same manner when calculating the proposed project emissions in Step 1.[76] As such, the EPA is not finalizing, as part of this action, a requirement that emissions increases or decreases be enforceable in Step 1 unless required by the applicable regulations.[77] As the EPA explained in the proposal, the EPA intends to treat projected actual emissions used in calculating emissions decreases from a project in the same manner as it does emissions increases since they are both part of the same project. Emission decreases should be considered simply part of the projected emissions for the

result in emissions increases below the significance threshold but which, if considered collectively as one project, would result in an emissions increase above the threshold. Separate activities that, when considered together, either decrease emissions or result in an increase that is not significant are not in view in the EPA's circumvention policy.''}

[73] 84 FR 39244, at 39250 (August 9, 2019). As explained in more detail in the proposal preamble for this action, the 2018 final action on project aggregation describes the procedure (*i.e.*, the ''substantially related'' test or ''circumvention policy'') ''for determining the circumstances under which nominally separate activities should reasonably be considered to be a single project.'' More specifically, the policy calls ''for sources and reviewing authorities to aggregate emissions from nominally-separate activities when they are ''substantially related.'' For a project to be substantially related, the ''interrelationship and interdependence of the activities [is expected], such that substantially related activities are likely to be jointly planned (*i.e.*, part of the same capital improvement project or engineering study), and occur close in time and at components that are functionally interconnected.'' In addition, the final ''project aggregation'' action adds that in general ''[to] be 'substantially related,' there should be an apparent interconnection—either technically or economically—between the physical and/or operational changes, or a complementary relationship whereby a change at a plant may exist and operate independently, however its benefit is significantly reduced without the other activity.''

[74] In this context, the term enforceable is intended to mean that the projections of a decrease in actual emissions for an existing emissions unit need to be enforceable as a practical matter (e.g., accompanied by an emission limit).

[75] 40 CFR 52.21(a)(2)(iv)(*b*)

[76] 84 FR 39244, at 39251 (August 9, 2019). (''[T]he EPA currently believes that 'the same reasoning that underpinned the 2002 NSR Reform Rule's treatment of projected actual increases applies equally to projected emissions decreases at Step 1.'').

[77] For new emissions units (including any units that have been in operation for less than two years), any emissions increases and decreases would be enforceable because the applicability test for new units is the actual-to-potential test. 40 CFR 52.21(a)(2)(iv)(*b*); *id.* 52.21(b)(4); *id.* 52.21(b)(7)

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project, not some discrete change from the project subject to different or additional requirements. A lower projected emission increase at an existing emissions unit involved in a project can have the same numerical effect on the result of the Step 1 applicability calculation by itself as a projected increase combined with a projected emissions decrease at another unit that is involved in the project. Therefore, we see no reason why enforceability of projected actual emissions should be required in one instance and not the other. Thus, the reasoning the EPA applied when declining to require that projected actual emissions be made enforceable as part of the 2002 NSR Reform rule continues to apply to projected actual emissions that are derived by combining increases and decreases from the same project in accordance with the clarification reflected in this rule.[78] As we explain in more detail in Section III.B.4 of this preamble, requiring that projected actual emissions decreases be enforceable in Step 1 could effectively replace the actual-to-projected-actual [79] applicability test for existing units with an actual-to-potential test,[80] or, more accurately, an actual-to-allowable test,[81] which would directly conflict with the EPA's reasoning for adopting the actual-to-projected-actual applicability test in 2002. Among other reasons, limiting projected actual emissions to allowable emissions (even if only for emissions decreases) could confiscate unused capacity of the source [82] and in some cases result in the source later retroactively becoming subject to major NSR requirements.[83] The EPA believes such an outcome would be unacceptable.

Another commenter added that the inclusion of emissions decreases in Step 1 in the NSR major modification applicability calculation must be enforceable, otherwise it would render Step 2 of the analysis meaningless. The commenter asserted that this rule would produce an absurd result by eviscerating Step 2's prohibition against crediting unenforceable emissions decreases for the purposes of netting out of NSR requirements.

The EPA disagrees that allowing for the consideration of emission decreases as part of the projected actual emissions from the project in Step 1 would render the contemporaneous netting provisions of the regulations superfluous or lead to absurd results. Allowing emissions decreases from the project under review to be considered in Step 1 does not mean that Step 2 is superfluous. Step 1 is limited to emissions increases and decreases from the *same* project. The source could still only account for emissions decreases from *another* project within the contemporaneous period in Step 2, subject to the other limitations of contemporaneous netting. In addition, the "substantially related" test mentioned previously, and further explained in Section III.B.4. of this preamble, applies to prevent aggregating into a single project those activities that do not represent such project, so decreases from activities that do not meet this test should not be considered in Step 1. Therefore, Step 2 is not superfluous because it clearly still serves a purpose of considering emissions increases and decreases from other projects that are contemporaneous with the proposed project and otherwise creditable. As discussed previously, if decreases from the project could not be considered in Step 1, that could potentially subject a project that decreases emissions overall to the major NSR permitting requirements. In addition, as noted previously, while the EPA is not requiring projections of decreases at Step 1 to be enforceable, the major NSR regulations contain a provision that "[r]egardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase." [84] Therefore, there is an inherent enforceable limitation on increases of actual emissions.

Finally, an additional commenter asserted that the agency's proposal foregoes statutorily specified benefits—avoidance of air quality violations, improved pollution-control technologies, offsetting emission reductions—in a fashion that is incompatible with any lawful exercise of *de minimis* discretion. This contention is countered by other commenters, however, who stated that this final rule is not an exemption from NSR applicability and is instead a clarification of pre-existing regulatory text specifying how NSR applicability is to be determined for projects that involve multiple types of emissions units.

We agree with the latter commenters. The clarification reflected in this rule is not based on inherent *de minimis* exemption authority and does not alter the EPA's determination of the level of emissions that is significant for any pollutant. As stated previously, each physical change or change in method of operation must still be compared to the significance levels to determine whether or not the change results in an emissions increase that is *de minimis*. All this rule does is clarify that, in projecting whether a project will result in a non-*de minimis* increase in actual emissions, the source can quantify such an increase based on the full scope of the project, including any portions of the project that are projected to decrease actual emissions. The EPA believes that allowing a source to conduct projections of actual emissions in Step 1 for the full scope of the project, including any decreases in emissions caused by the project, is the best reading of CAA section 111(a)(4) because it will ensure that projects that overall decrease emissions or result in a *de minimis* increase in emissions will not be subject to the major NSR program.

4. Defining the Scope of a Project

In the proposal, we said that defining the scope of the project was within the discretion of the source. We also indicated that when a source is defining the scope of the project: (1) Separating activities into smaller projects (*i.e.*, under aggregation) to circumvent the NSR major modifications permitting requirements could be prevented by applying the interpretation and policy

[78] 67 FR 80185, at 80204 (December 31, 2002). In the 2002 NSR Reform rule, the EPA expressly declined to adopt a requirement under which a source's projected actual emissions would have become an enforceable emission limitation because: (1) "we are concerned that such a requirement may place an unmanageable resource burden on reviewing authorities," and (2) "we also believe that it is not necessary to make . . . future projections enforceable in order to adequately enforce the major NSR requirements. The Act provides ample authority to enforce the major NSR requirements if . . . [a] physical or operational change results in a significant net emissions increase at . . . [a] major stationary source."

[79] The actual-to-projected-actual applicability test for projects that only involve existing emissions units is the test defined in 40 CFR 52.21(a)(2)(iv)(*c*).

[80] The actual-to-potential test for projects that only involve new emission units is the test defined in 40 CFR 52.21(a)(2)(iv)(*d*).

[81] This is because under the approach requiring enforceability of emissions decreases, the projected actual emissions for an emissions unit would become the allowable emissions for that unit. The definition of allowable emissions can be found at 40 CFR 52.21(b)(16).

[82] For example, if a source was required to establish an enforceable emission limit to consider a decrease that is the result of the project, the source may not be able to later increase production or hours of operation, which would otherwise not even be considered a physical change or change in method of operation subject to NSR applicability. 40 CFR 52.21(b)(2)(iii)(*f*).

[83] This is the opposite of the confiscation of unused capacity, if such an allowable emissions limitation was required and is subsequently relaxed to accommodate an unrelated increase in production rate or hours of operation, and that relaxation resulted in the modification becoming major, the source could become subject to major NSR requirements as if construction had not yet commenced. 40 CFR 52.21(r)(4).

[84] 40 CFR 52.21(a)(2)(iv)(*b*).

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set forth in the 2018 final action on project aggregation and (2) adding multiple activities into bigger projects (*i.e.*, over aggregation) was not precluded by any prior interpretation or policy.[85] On this latter point, we added that separate activities which, when considered together, either decrease emissions or result in an increase that is not significant were not previously considered as part of the EPA's circumvention policy. However, we requested comment on whether we should instead apply the "substantially related" criteria to prevent over-aggregation in Step 1 and asked what the impact of applying such a standard would be.[86]

Multiple commenters expressed support for the proposed concept that the scope of a project be at the discretion of the source and that the absence of a provision defining the scope of a project does not create an incentive to over-aggregate.[87] Commenters supported this proposed concept on the grounds that this discretion would allow sources to undertake activities that would reduce overall emissions in cases where a project is comprised of multiple emissions units.

Several commenters, however, expressed concerns that the scope of a project to which project emissions accounting is applied should be defined.[88] Otherwise, any ambiguity in defining the scope of the project would constrain a reviewing authority's ability to verify whether the source has reasonably exercised its discretion in applying project emissions accounting to a project. Other commenters added that the lack of criteria for determining the scope of a project would allow sources to circumvent NSR requirements by selectively considering emissions decreases with unrelated and non-contemporaneous increases. To this point, commenters expressed concern that, under the proposed rule, sources would be able to circumvent NSR requirements by finding contemporaneous emission reductions within the facility and considering them to be part of the project, while not incorporating similar contemporaneous emission increases in the scope of the project.

The EPA does not concur with the commenters who stated that circumvention of the NSR permitting requirements is a likely outcome of the proposed rule because, while not previously contemplated by our project aggregation policy, the EPA has concluded after review of the comments received on the proposal for this action that the "substantially related" test from our 2018 final action on project aggregation interpretation and policy provides the appropriate basis for sources to determine the scope of a project in Step 1 of the NSR applicability analysis. We believe that applying the 2018 final action on project aggregation interpretation and policy in this context alleviates concerns about potential NSR circumvention in Step 1 of the NSR major modification applicability test. The "substantially related" test, which is reflected in the 2018 final action on project aggregation, calls for sources to aggregate emissions from nominally separate activities when there is an apparent technical or economical interconnection between the physical and operational changes. This 2018 final action on project aggregation also includes a policy of applying a rebuttable presumption that project activities that occur outside a 3-year period are not related and should not be grouped into one project. The EPA has observed that "[w]hen activities are undertaken three or more years apart, there is less of a basis that they have a substantial technical or economic relationship because the activities are typically part of entirely different planning and capital funding cycles." [89]

Under this 2018 final action on project aggregation interpretation and policy, sources continue to have discretion in defining the scope of the project based on their business needs, but at the same time should not arbitrarily group project activities for the purpose of avoiding the NSR major modification requirements. Rather, in accordance with the 2018 final action on project aggregation, sources should define a project to include all activities, and only those activities, that meet the "substantially related" test.

Other commenters asserted that the EPA failed to address the possibility that facilities could circumvent NSR by proffering in Step 1 an emissions decrease that turns out to be nothing but a temporary reduction, thus avoiding the need to even modify equipment or install a pollution control device. A commenter added that some courts have imposed a statute of limitations that runs 5 years from the date of the modification and that the proposal, in conjunction with those rulings, invited a source to claim unenforceable decreases to avoid NSR, then simply avoid following through once the limitations period has passed.

We disagree with these commenters. The decrease in emissions in Step 1 will be calculated in most cases using the actual-to-projected-actual applicability test, and the projected actual emissions calculation in that test must be based on consideration of all relevant information.[90] If there is a "reasonable possibility" that the project may result in a significant emissions increase, as defined in the regulations at 40 CFR 52.21(r)(6), the source must meet applicable pre- and post-project recordkeeping, monitoring, and reporting requirements that apply for 5 or 10 years following the resumption of regular operation after the project, depending on the nature of the project. As such, the "reasonable possibility" provisions would provide the records necessary for reviewing authorities to ensure that the emissions reductions are not temporary and provide for enforcement of the major NSR program requirements, as necessary. The EPA also believes that the regulatory text at 40 CFR 52.21(a)(2)(iv)(*b*) that states, "[r]egardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase" provides a safeguard that will ensure that the emissions reductions are not temporary or illusory. If a source, upon resuming regular operation after a project, fails to realize a reduction in emissions that was projected from a particular unit, or if that reduction is less than was projected, such that the overall emissions increase from the project exceeds the applicable significant emissions rates, then the source could be subject to NSR at that time and potentially an enforcement action. While a commenter expressed concern that some sources may claim unenforceable decreases to avoid NSR and then simply avoid following through with those decreases once the statute of limitations period has passed, the EPA views this possibility as remote because of the safeguard at 40 CFR

[85] As stated previously, the term "project" is defined in our regulations at 40 CFR 52.21(b)(52). In general, we use the term "project" to mean the physical change or change in method of operation under review, though this can encompass one or more activities at an existing major source. On the other hand, the term "project aggregation" used in the agency's 2018 project aggregation interpretation and policy discusses how multiple activities should be evaluated to determine whether these activities constitute one project.

[86] 84 FR 39244 at 39251 (August 9, 2019).

[87] These comments can be found in Section 5.0 of the Response to Comments document for this action.

[88] These comments can be found in Section 5.0 of the Response to Comments document for this action.

[89] 74 FR 2376, at 2380 (January 15, 2009).

[90] 40 CFR 52.21(b)(41)(ii)(*a*).

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52.21(a)(2)(iv)(*b*) and the potential for civil, or even criminal, enforcement.[91]

Finally, several commenters questioned the EPA's decision to forgo a requirement that emissions reductions be enforceable and creditable in order to be used in project emissions accounting. These commenters stated that allowing sources to include uncreditable and unenforceable projected project emission decreases with the knowledge that the EPA will not second-guess those projections, referring to the Actual-to-Projected-Actual Applicability Test Memorandum issued by the EPA in December 2017,[92] readily invited NSR circumvention and increased air pollution with no ability for third-party enforcement.

The EPA disagrees with these commenters. First, as explained in the August 2019 proposal and in the legal rationale section of this final action (Section III.B.3), the EPA intends to treat the calculation of emissions decreases from a proposed project in the same manner as it does emissions increases from the same proposed project (*i.e.*, including emissions increases and decreases in Step 1 because both are necessary to determine the emissions resulting from the project). Second, requiring that projected actual emissions be made enforceable at the time of the project could effectively replace the actual-to-projected-actual applicability test with an actual-to-potential test, or, more accurately, an actual-to-allowable test, which would directly conflict with the EPA's reasoning for adopting the actual-to-projected-actual applicability test in 2002 and with what the EPA believes is the best reading of CAA section 111(a)(4). Third, the EPA believes that a requirement that projected actual emissions be made enforceable at the time of the project would effectively confiscate any unused capacity at the affected emissions unit and potentially require that any future project(s) that might increase emissions from that unit trigger major NSR retroactively.[93] In responding to comments on the actual-to-potential methodology in 2002, the EPA noted that the establishment of an enforceable permit limit ''may restrict the ability of a source to increase its emissions in association with an increase in production or hours of operation, which when done alone are not normally considered as physical or operational changes.'' [94] The EPA also stated ''[w]e generally agree with commenters who have argued that existing emissions units in general (including replacement and reconstructed units) have ample track record such that the projection of the proposed project emissions alone is sufficiently reliable and enforceable and thus the burdens of up-front permit caps on emissions are unnecessary'' and ''[w]e disagree with the commenters who thought that the 'actual-to-potential' test should be retained because, among other things, the recordkeeping requirements associated with the 'actual-to-projected-actual' test would be burdensome . . . for most sources, the burden of recordkeeping [associated with use of the actual-to-projected-actual applicability test] is substantially less than the present burden of obtaining a permit containing an up-front cap on actual emissions.'' [95] Thus, consistent with our reasoning in 2002, the EPA does not believe that these outcomes and making emissions reductions enforceable in Step 1 are necessary in order for sources evaluating projects that involve existing emissions units to reasonably determine whether such projects would result in a significant increase in *actual* emissions just because the project includes a calculated decrease in emissions at one or more emissions units.

In any event, the regulations provide that ''[r]egardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.'' [96] Therefore, the EPA believes the NSR regulations do provide a mechanism for enforcement if a project is erroneously projected not to result in a significant emissions increase. In addition, many, if not most, of emissions decreases that result from a project will be due to the installation of controls or the removal of an emissions unit. The EPA still believes, as it did in 2002, that even if, in accounting for the full impact of a project in Step 1, a source would not be required to obtain a major NSR permit, the large majority of these projects would still be required, as noted earlier, to obtain a minor NSR permit under the state or local air agency minor NSR permitting program and, therefore, the project activities and any emissions decrease(s) accounted for would be documented in those permit records.[97] The EPA-approved implementation plans will also still need to include enforceable emission limits and other control measures intended to protect air quality and a program for ''regulation of the modification and construction of any stationary source within the areas covered by the plan as necessary to assure that national ambient air quality standards are achieved, including a permit program as required in parts C and D of this subchapter.'' [98] Nothing in this final rule conflicts with or diminishes these SIP requirements.

Finally, the December 2017 ATPA Memorandum is not within the scope of this rulemaking, nor does it have any bearing on this final rule. The December 2017 ATPA Memorandum communicated how the EPA intends to apply and exercise its enforcement discretion related to certain aspects of the applicability provisions of the NSR regulations. The policy contained in that Memorandum does not constitute a rule, regulation, or other legally binding requirement and it does not change or substitute for any law, rule or regulation, or other legally binding requirement. We, therefore, do not agree that this final rule or the December 2017 APTA Memorandum will place any limitations on third-party enforcement of the major NSR program. Nothing in this final rule changes the enforcement provisions available under the CAA to enforce the major NSR permitting requirements nor the ability of third parties to bring potential enforcement actions to the EPA's attention if they suspect that a source has avoided the major NSR permitting requirements.

5. Monitoring, Recordkeeping and Reporting of Emissions Decreases in Step 1 of the NSR Major Modification Applicability Test

The provisions of 40 CFR 52.21(r)(6) apply to projects involving existing emissions units at a major stationary source in circumstances where the

[91] If an activity that was included in an initial projection of actual emissions no longer falls within the scope of the project, the source should reevaluate the projected emissions change of the project without that activity. Therefore, contrary to the commenters concerns, if a source initially includes an activity that decreases emissions in its projection but subsequently decides that that activity is not within the scope of the project, it must redo the project's projected emissions without that emission decreasing activity.

[92] Letter from E. Scott Pruitt, to Regional Administrators, ''New Source Review Preconstruction Permitting Requirements: Enforceability and Use of the Actual-to-Projected-Actual Applicability Test in Determining Major Modification Applicability,'' December 7, 2017 (''December 2017 ATPA Memorandum''), available at: *https://www.epa.gov/sites/production/files/2017-12/documents/nsr_policy_memo.12.7.17.pdf.*

[93] 40 CFR 52.21(r)(4).

[94] 2002 NSR Reform Rule Technical Support Document at I–4–7.

[95] *Id.* at I–4–7, 8.

[96] 40 CFR 52.21(a)(2)(iv)(*b*).

[97] The EPA expects that as part of the minor NSR permitting process, the emissions increases and decreases occurring from the project will be documented either in the permit application, demonstrating the non-applicability of major NSR, or as requirements in the minor NSR permit itself.

[98] 42 U.S.C. 7410(a)(2)(C).

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owner or operator elects to use the actual-to-projected-actual applicability test for calculating projected actual emissions and there is a reasonable possibility (as defined in subparagraph (r)(6)(vi)) that a project that is not part of a major modification may result in a significant emissions increase. When the reasonable possibility criteria in subparagraph (r)(6)(vi) are triggered, specific pre- and post-project recordkeeping, monitoring and reporting requirements in paragraph (r)(6) must be met, depending on the circumstances. Those include the requirement that before beginning actual construction on the project, the owner or operator document and maintain a record including a description of the project, identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project, and a description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant (including certain specified information).

The requirements of 40 CFR 52.21(r)(6) also include pre-project reporting (for electric utility steam generating units) and post-project monitoring and reporting of emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by *any emissions unit identified* in the pre-project record whose emissions could be ''affected'' by the project. Under these monitoring provisions, sources must calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5- or 10-years following resumption of regular operations after the change, depending on the type of change at the unit(s). Post-project reporting is required for electric utility steam generating units and is triggered when certain specific criteria that are applicable to all other categories of emissions units are met. In accordance with 40 CFR 52.21(r)(7), the information required to be documented and maintained pursuant to paragraph (r)(6) shall be available for review upon a request for inspection by the reviewing authority or the general public. As described in the proposal preamble, the requirements of 40 CFR 52.21(r)(6) apply equally to units with projected increases and projected decreases in emissions, as long as there is a reasonable possibility that the project could result in a significant emissions increase and those units are part of the project (*i.e.*, their emissions ''could be affected'' by the project).

Various commenters expressed that considering emissions increases and decreases in Step 1 of the NSR major modification applicability test would not necessitate any additional monitoring, recordkeeping, or reporting requirements to promote NSR compliance because the current requirements under 40 CFR 52.21(r)(6) are adequate for this purpose. A couple of these commenters came to this determination because, in the existing rules, the EPA has already determined that sources should not be required to track small projected increases that are well below the relevant significant emissions rates, and there is even less reason to track projected decreases, since the ''possibility'' of a significant increase is even more remote. Some of these commenters noted that existing monitoring, recordkeeping, and reporting provisions in state and federal laws that cover all NSR-affected ''major sources,'' and particularly the requirements for ''. . . semiannual reporting, compliance reporting and certifications, and periodic emissions inventory reporting under Title V permits, are stringent and adequate to assure that NSR violations will not occur as a result'' of considering emissions increases and decreases in Step 1. Another commenter added that minor source permitting requirements will often apply to projects that are not subject to major NSR permitting and that the reviewing authority will verify a source's rationale for determining that a project is minor.

Other commenters, however, felt that the ''reasonable possibility'' provisions of 40 CFR 52.21(r)(6) are insufficient to guard against potential circumvention of NSR requirements. Commenters in this group stated that sources would be able to forgo the reasonable possibility requirements by projecting that an emissions increase will be less than 50 percent of the significant emission increase level. A few commenters added that reliance on the provisions of 40 CFR 52.21(r)(6) would complicate enforcement actions because the calculations sources conduct to comply with these provisions often do not include all emissions units associated with a project, especially affected units that are not modified or constructed under a project. These commenters emphasized that while sources can explain if annual emissions from a project exceed the baseline emissions by an amount greater than the significant emission rate, assessing the validity of such explanations places an undue burden upon the reviewing authority.

Several commenters suggested that the problems related to the lack of monitoring, recordkeeping, and reporting requirements for sources whose emissions do not meet the ''reasonable possibility'' threshold is compounded by the EPA's decision to not require that emissions decreases considered in Step 1 be enforceable. According to these commenters, sources considering emissions increases and decreases in Step 1 of the NSR major modification applicability test would be able to pair an unenforceable emission decrease with an otherwise significant emission increase to avoid NSR, and can then avoid tracking the actual emission increase as a result of the changes by ''projecting'' that the Step 1 net emissions change would be less than 50 percent of the significant emissions increase level. These commenters asserted that the Administrator's directive that the EPA not question a source's NSR calculations (except in cases of ''clear error''), referring to the December 2017 APTA Memorandum, means there is little chance that facilities' calculations will be audited and even less chance that the EPA will be able to check the actual emission increases resulting from changes.

The EPA agrees with the commenters that concluded that the regulations at 40 CFR 52.21(r)(6) are sufficient and appropriate to ensure that adequate records are maintained in circumstances where there is a reasonable possibility, as defined in the regulations, that a project determined not to constitute a major modification could result in a significant emissions increase. Those provisions apply equally to projects that trigger the reasonable possibility criteria, regardless of whether those projects include only increases, or increases and decreases in emissions, consistent with the clarifications in this final rule. We also agree that other records required to be maintained and reported under CAA programs will support compliance with the NSR applicability regulations and enforcement of those regulations as necessary. In imposing reasonable possibility recordkeeping requirements, the EPA ''strove for a balance between ease of enforcement and avoidance of requirements that would be unnecessary or unduly burdensome on reviewing authorities or the regulated community.'' [99] Beyond alleging potential NSR circumvention, the commenters who oppose the use of the reasonable possibility provisions did not provide any persuasive rationale for

[99] 72 FR 72607, at 72610 (December 21, 2007). The ''reasonable possibility'' provisions of the existing regulations are currently in litigation. *State of New Jersey* v. *EPA*, No. 08–1065 (D.C. Cir.).

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treating emissions increases and decreases differently for purposes of tracking emissions under those requirements. Since projected actual emissions must be based on all relevant information, sources may not arbitrarily project emissions below the applicability levels for these recordkeeping, monitoring, and reporting requirements.

We agree that in many or most cases, projects that involve both increases and decreases in emissions in Step 1 that do not trigger the reasonable possibility provisions will be subject to minor NSR permitting requirements. As such, records of the project activities, the emissions increases and any emissions decreases associated with those activities, the applicability test and the corresponding emissions calculations should be available or made available for review as part of the permit application and permit records for the project, which include the permit terms.

The EPA, however, disagrees that the ''reasonable possibility'' provisions at 40 CFR 52.21(r)(6) are insufficient to guard against NSR circumvention as a result of considering emissions increases and decreases in Step 1 and that reliance on those provisions would complicate enforcement and/or place undue burden on reviewing authorities for the reasons cited. First, as explained in Section III.B.4 of this final rule preamble, applying the EPA's 2018 final action on project aggregation interpretation and policy makes clear that any decreases from activities that are accounted for in Step 1 should be ''substantially related'' to any increases from activities that are part of the same project, meaning that those decreases in fact result from the project. Second, manipulating NSR major modification applicability calculations to circumvent NSR and/or avoid the ''reasonable possibility'' requirements in the regulations could subject a source to the NSR requirements, substantial civil penalties, and/or criminal liability. The regulations provide that ''[r]egardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.'' [100] Thus, if any emissions decreases are overstated, and/or any increases understated, such that the emissions projection at the time shows a source is not subject to NSR or the reasonable possibility requirements, the source will be subject to NSR if and when the project actually results in a major modification. Finally, and as stated previously, we do not agree that the December 2017 APTA Memorandum will have any effect on third-party enforcement of the major NSR program. Nothing in this final rule changes the enforcement provisions available under the CAA to enforce the major NSR permitting requirements nor the ability of third parties to alert the EPA if they suspect that a source has improperly avoided the major NSR permitting requirements.

Other commenters challenged the EPA's reference to the reasonable possibility standard in the proposal on procedural grounds. These commenters stated that the reasonable possibility provisions are not only insufficient, but that they are ''arbitrary and capricious'' because the EPA failed in the proposal of this rule to specify how the provisions of 40 CFR 52.21(r)(6) are applicable to the consideration of emissions increases and decreases in Step 1 project emissions accounting. One commenter added that ''at the outset, depending on how 'the project' is defined by the source operator, the plain text of [40 CFR 52.21(r)(6)], on its face, does not apply to emissions decreases.''

The EPA disagrees with these commenters. The requirements of 40 CFR 52.21(r)(6) apply when there is a reasonable possibility that the project could result in a significant emissions increase and that those units are part of the project (*i.e.*, their emissions ''could be affected'' by the project). While practically-speaking this would only apply to a project resulting in an overall increase in emissions because an overall decrease would clearly not have a reasonable possibility of triggering NSR, this does not mean that decreases cannot be considered when determining whether a project would result in an overall increase sufficient to trigger these requirements. When the reasonable possibility criteria in subparagraph (r)(6)(vi) are triggered by an overall increase, specific pre- and post-project recordkeeping, monitoring and reporting requirements in paragraph (r)(6) must be met, as described previously.

Based on the regulations themselves and the comments received, the EPA is concluding that the provisions of 40 CFR 52.21(r)(6) are sufficient for purposes of enforcing the NSR major modification applicability requirements including the clarifying revisions to those applicability requirements in this final rule.

6. Considering Emissions Decreases in Step 1 for Delegated and SIP-Approved Programs

In the proposal, we indicated that if this rule was finalized, any revisions to the regulations at 40 CFR 52.21 would apply to the EPA and reviewing authorities that have been delegated federal authority by the EPA to issue PSD permits on behalf of the EPA (via a delegation agreement with an EPA Regional Office).[101] The EPA also indicated that for state and local air agencies that implement the NSR program through EPA-approved SIPs,[102] the EPA also proposed to revise the regulations for approval of such programs (40 CFR 51.165 and 40 CFR 51.166) to be consistent with the proposed revisions to 40 CFR 52.21(a)(2)(iv).[103] For these SIP-approved programs, the EPA also indicated that if the EPA were to finalize the clarifications being proposed, reviewing authorities may not need to revise their state regulations and submit SIP revisions if the current NSR major modification applicability provisions in those regulations can be interpreted to allow for project emissions accounting or if those state and local air agencies incorporate the federal NSR regulations by reference without a date restriction. Lastly, the EPA mentioned that it was currently aware of a few states and local programs where the applicable SIP-approved regulations expressly preclude project emissions accounting. Thus, we requested comment on whether the EPA should determine that the proposed revisions to 40 CFR 51.165(a)(2)(ii)(F) and (G) and 40 CFR 51.166(a)(7)(iv)(*f*) and (g) constitute minimum program elements that must be included in order for state and local agency programs implementing part C or part D to be approvable under the SIP.[104]

Commenters expressed various positions regarding whether the proposed revisions should constitute minimum program elements that must be included for state and local programs implementing parts C or D of Title I of

[100] 40 CFR 52.21(a)(2)(iv)(*f*).

[101] There are currently 7 states that have full or partial delegation of authority to issue PSD permits on behalf of the EPA.

[102] The applicable regulations for state and local air agencies that implement the NSR program through EPA-approved SIPs include 40 CFR 51.165(2)(ii)(F) and (G); to 40 CFR 51.166(a)(7)(iv)(*f*) and (g). Any references to SIP-approved plans also refer to the plans submitted by local air agencies to the EPA for approval.

[103] *Supra* n. 03. As indicated in footnote n. 03, the revisions being finalized in this action also apply to Appendix S of part 51.

[104] Such a determination was made with respect to the NSR regulatory revisions the EPA made in 2002. 67 FR 80185, at 80240 (December 31, 2002).

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the CAA to be approvable under a SIP.[105] A few commenters stated that this final rule should constitute minimum program elements that must be included in an EPA-approved SIP on the basis that the changes in this final rule are clarifications of the regulations adopted by the 2002 NSR Reform Rule. Another one of these commenters stated that requiring the proposed rule revisions to be minimum program elements for programs implementing part C or part D to be approvable under a SIP would ensure national consistency.

Various commenters, however, opposed the concept of making project emissions accounting a minimum program element for programs implementing part C or part D to be approvable under a SIP. Some of these commenters noted that under section 116 of the CAA, states can adopt SIP provisions that are more stringent than those required by the EPA's regulations. A couple of commenters added that requiring the implementation of project emissions accounting would run afoul of the sovereign authority of state governments.

After reviewing the comments received on this matter, the EPA has determined that the revisions to the regulations at 40 CFR 52.21 adopted in this final rule apply to the EPA and reviewing authorities that have been delegated federal authority from the EPA to issue major NSR permits on behalf of the EPA.[106] For state and local air agencies that implement the NSR program through EPA-approved SIPs, the EPA agrees with those commenters who argued that section 116 of the CAA allows these states and local air agencies to adopt more stringent SIP emission control requirements than required by the EPA's regulations.[107] Thus, the EPA is concluding that reviewing authorities that do not allow for project emissions accounting have applicability requirements that are at least as stringent as those required by the Act or the EPA's implementing regulations and, therefore, are not required to submit SIP revisions or stringency determinations to the EPA as a result of this action. This is because sources that are not allowed to use project emissions accounting may be subject to major NSR even where a more-complete accounting of their emissions (*i.e.*, accounting of both emissions increases and decreases in Step 1 of the NSR major modification applicability test) would reveal that the project produced either an emissions decrease or a *de minimis* increase in emissions.

For SIPs approved under 40 CFR 51.166, the EPA has determined that conforming state/local plan revisions will not be subject to the deadline by which a reviewing authority is typically required to revise its implementation plan in response to amendments to the federal regulations.[108] Similarly, because the EPA views not allowing project emissions accounting to be at least as stringent as the requirements under 40 CFR 51.165, plans already approved under the current version of that section of the CFR will continue to be at least as stringent as the revised regulations and states and local air agencies will not need to submit revisions to already approved plans.[109]

7. Environmental and Economic Impact Considerations of Project Emissions Accounting

Two commenters asserted that the EPA was required to evaluate the environmental impacts of the proposed rule. One of these commenters argued that the EPA's lack of permitting data does not excuse the agency from conducting an analysis of the environmental impacts of the rule and that the EPA must use data from its own records and/or request data from state and local reviewing authorities to conduct such an analysis.

In the proposal preamble we indicated that we are unable at this time to estimate any potential environmental or economic impacts or changes in emissions associated with project emissions accounting because most NSR permits are issued by state and local air agencies and the EPA generally lacks information on the economic and environmental impacts of NSR permits. NSR permitting is a case-by-case process and sources make permitting decisions based on many factors. Furthermore, neither the EPA nor state and local reviewing authorities have access to any records of decisions made by sources which would indicate whether a project was or was not undertaken in view of the unavailability of project emissions accounting. We do not, for example, require the reporting of any information concerning projects that are not pursued. Thus, in the proposal, we asked that commenters provide information on particular examples that could assist the EPA in providing some level of qualitative impacts analysis when finalizing this action.

In response to this solicitation, a few commenters noted that project emissions accounting is consistent with the CAA and with the congressional intent that the PSD and NNSR preconstruction permitting programs only apply when an existing source undertakes a project resulting in a significant increase in emissions. Several commenters, however, indicated that this final rule would result in negative environmental impacts by allowing sources to forgo major NSR permitting and the associated BACT or LAER requirement. Commenters stated that the emissions increases that would result from this final rule would contravene the purpose of the NSR program to require permits where changes at industrial facilities might increase air pollution. Other commenters noted that this final rule may have the potential of reducing overall emissions by removing a disincentive for sources seeking to undertake projects that would improve the energy efficiency of their operations.

After consideration of the comments received on this matter, we would like to reiterate that this final rule will not allow projects that themselves result in a significant emissions increase (*i.e.*, an increase greater than *de minimis* levels) and a significant net emissions increase to proceed without obtaining a major NSR permit. Rather, the final rule merely clarifies the NSR major modification applicability test to allow for a more accurate accounting of a project's impacts on air quality to the surrounding area by allowing a source to consider all changes in emissions—both increase and decreases—that result from a project in its calculation of the proposed project emissions. This is consistent, rather than contrary, to the congressional intent for the NSR program. Additionally, despite a commenter's assertion that this rule will allow sources to emit more by circumventing the BACT or LAER requirements, there is no evidence to suggest that the final rule will result in greater overall emissions increases than would otherwise be allowed from projects affected by the rule. For example, as the EPA noted in the proposed rule and as indicated by some commenters, it is equally conceivable that accounting for emissions decreases in Step 1 of the NSR major modification

[105] A SIP refers to an implementation plan submitted by a State to the EPA for approval. In this preamble, this term also refers to implementation plans submitted by local agencies.

[106] PSD program provisions have been delegated to reviewing authorities. Reviewing authorities in Indian country can request delegation of the major NA NSR provisions, but to date, none have done so.

[107] *Union Electric* v. *EPA*, 427 U.S. 246,263–264 (1976).

[108] 40 CFR 51.166(a)(6). The EPA's view is that no state is ''required to revise its implementation plan by reason of'' the amendment to 51.166 reflected in this final rule.

[109] 40 CFR 51.165(a)(1), (a)(2)(i), and (a)(6) (allowing deviations only when at least as stringent)

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applicability test will incentivize sources to undertake energy efficiency and/or other environmentally beneficial projects that they might otherwise have forgone. In addition, just because a project might result in a significant increase in emissions in Step 1 without the accounting for emissions decreases from the project, does not mean that the project would be subject to the BACT or LAER requirements. Such a project could still result in a net emissions decrease, or a net emissions increase that is not significant and does not trigger the major NSR permitting requirements. It is therefore improper to compare the use of project emissions accounting to the application of BACT or LAER. These outcomes are not an either-or proposition for a project that would not result in a significant emissions increase when accounting for decreases but would result in a significant emissions increase when decreases from the project are not considered in Step 1.

Several commenters submitted examples of actual projects that involved emissions decreases that would be more likely to proceed with the availability of project emissions accounting. These examples included replacement projects, projects involving the installation of control equipment, and fuel changes—projects that may result in a reduction of overall emissions but may be forgone if decreases associated with the projects are not considered. For example commenters mentioned that, a source may forgo, the installation of an end-of-life replacement to avoid NSR permitting since the emissions would appear as an emissions increase in Step 1 of the applicability determination even when the replacement would have reduced the potential emissions. While the new unit in general may be larger in capacity, their design and material changes generally entail increased efficiency and lower emissions. Newer units may also generally contain inherent emissions controls (*e.g.*, heaters equipped with low NO_X burners) that also lower the source's overall emissions. If the source can count emissions decreases from this project under project emissions accounting, then the source may be more likely to undertake the project, or the source owner might expedite it. However, the project may be foregone if the emission decreases could only be considered as part of a more complex Step 2 contemporaneous netting analysis. Furthermore, commenters noted that proposing a project (*e.g.* expansion that results in increased tank throughput and cooling capacity) may also include the installation of emissions control equipment such as installing a geodesic dome to an external floating roof tank to control volatile organic content (VOC) emissions, retrofitting a cooling water tower with drift eliminators to reduce particulate matter emissions; and/or installing dual-seal pumps to reduce fugitive VOC emissions. If the consideration of emissions decreases as part of project emissions accounting at Step 1 were not available, a project that also involves the installation of emissions control equipment that reduces overall emissions could be foregone due to the complexities of Step 2 contemporaneous netting. Project emissions accounting may also expedite the environmental benefits associated with converting a unit to a lesser-emitting fuel source. For example, when emissions decreases are considered at Step 1, a source owner or operator proposing a project that replaces existing oil-fired boilers with lesser-emitting natural gas boilers might not trigger permitting at Step 1, but it would reduce its overall emissions. If project emissions accounting were not available, the source would likely trigger Step 1 and also undergo the Step 2 analysis to determine if it needs a major modification permit for its proposed project. Under Step 2, the source owner or operator would be required to consider all other contemporaneous emissions increases and decreases from the project, usually within a five-year time period, even though the project itself would have already resulted in a decrease in the actual emissions from the facility. Therefore, a source may decide to forgo transitioning to a lesser-emitting fuel to avoid going through some of the complexities of Step 2 contemporaneous netting or potentially having to receive a major NSR permit for a project that decreases emissions. The Response to Comments document for this final action contains more details about these projects.[110]

Based on the information and examples provided, the EPA believes that considering the full scope of the impact of a project ensures that congressional intent for the NSR program, to ensure environmental protection while allowing for economic growth, is met. That is to say, this rule provides more clarity to sources and reviewing authorities applying the NSR applicability test and potentially reduces the permitting burden for sources undertaking economically-beneficial projects that do not produce a greater than *de minimis* increase in emissions. The EPA has provided a more complete discussion of the potential environmental impacts of the rule as well as the difficulties of accurately projecting such impacts in the Environmental Justice Considerations Section of this preamble and the same analysis is provided in the Response to Comments document for this final action.

[110] These comments can be found in Section 4.0 and 5.0 of the Response to Comments document for this action.

IV. Environmental Justice Considerations

In the proposal, the EPA stated that we did not believe that the proposed revisions to the NSR major modification applicability regulations would have any effect on environmental justice communities because the EPA's NSR regulations in place since the 2002 NSR Reform Rule was finalized to allow project emissions accounting. As such, the EPA expected no increase in the permitting burden for sources, reviewing authorities or environmental justice communities after finalization of the proposed rule revisions.

Nevertheless, one commenter argued that because the proposed revisions would alter how major modifications are determined under the NSR program, they would result in fewer modifications being subject to major NSR and, therefore, the environmental justice impacts of the rule must be considered accordingly. The commenter added that it is clear that the intention of this rulemaking is to reduce the number of projects that are considered major modifications under NSR and this will reduce public health and welfare protection. According to the commenter, this is because fewer facilities will be required to ensure that the changes they are making are protective of ambient air quality and fewer facilities will be required to install pollution controls on new or modified units because their changes will not trigger NSR. Moreover, the commenter stated that environmental justice initiatives stem from the fact that facilities with the worst environmental impact are more likely to be located in areas with higher poverty rates, communities of color, or tribal lands.

We continue to believe that these rule revisions will not impact environmental justice communities in a manner that is different than any impact this rule might have in any other area of the country. As we explained in the proposal preamble, and as stated elsewhere in this preamble, we interpret our regulations to already allow for

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project emissions accounting even in the absence of this rule. This rulemaking will only serve to provide greater clarity with respect to the major NSR applicability procedures and, thus, will incentivize states to implement project emissions accounting at their discretion. This improved clarity itself confers potential benefits to environmental justice communities by removing a disincentive to the implementation of energy efficiency improvements and other environmentally beneficial projects at industrial sources for sources that might have forgone those projects due to the complexity of the Step 2 contemporaneous netting analysis.

However, to aid stakeholders in their assessment of the potential impacts of this action and to be responsive to the comments received, we did perform a qualitative analysis of a few examples of actual projects that may reduce air emissions due to the availability of project emissions accounting at Step 1 of the NSR major modification applicability test. These examples are based on the comments received during the public comment period for this final action, are included as part of the Response to Comments document for this final action and are also summarized in the next few paragraphs of this section of the preamble. This analysis, however, does not provide a qualitative estimate of the potential environmental impacts of accounting for emissions decreases at Step 1 of the NSR major modification applicability test since the commenters did not provide information of any potential emissions increases or decreases that would have occurred in these examples based on the availability of project emissions accounting at Step 1.[111]

Examples of replacement projects: A source may forgo, the installation of an end-of-life replacement to avoid NSR permitting since the emissions would appear as an emissions increase in Step 1 of the applicability determination even when the replacement would have reduced the potential emissions. While the new unit in general may be larger in capacity, their design and material changes generally entail increased efficiency and lower emissions. Newer units may also generally contain inherent emissions controls (*e.g.*, heaters equipped with low NO_X burners) that also lower the source's overall emissions. If the source can count emissions decreases from this project under project emissions accounting, then the source may be more likely to undertake the project, or the source owner might expedite it. However, the project may be foregone if the emission decreases could only be considered as part of a more complex Step 2 contemporaneous netting analysis.

Examples of projects involving the installation of emissions control equipment: Proposing a project (*e.g.* expansion that results in increased tank throughput and cooling capacity) may also include the installation of emissions control equipment such as installing a geodesic dome to an external floating roof tank to control volatile organic content (VOC) emissions, retrofitting a cooling water tower with drift eliminators to reduce particulate matter emissions; and/or installing dual-seal pumps to reduce fugitive VOC emissions. If the consideration of emissions decreases as part of project emissions accounting at Step 1 were not available, a project that also involves the installation of emissions control equipment that reduces overall emissions could be foregone due to the complexities of Step 2 contemporaneous netting.

Examples of projects involving fuel changes: Project emissions accounting may also expedite the environmental benefits associated with converting a unit to a lesser-emitting fuel source. For example, when emissions decreases are considered at Step 1, a source owner or operator proposing a project that replaces existing oil-fired boilers with lesser-emitting natural gas boilers might not trigger permitting at Step 1, but it would reduce its overall emissions. If project emissions accounting were not available, the source would likely trigger Step 1 and also undergo the Step 2 analysis to determine if it needs a major modification permit for its proposed project. Under Step 2, the source owner or operator would be required to consider all other contemporaneous emissions increases and decreases from the project, usually within a five-year time period, even though the project itself would have already resulted in a decrease in the actual emissions from the facility. Therefore, a source may decide to forgo transitioning to a lesser-emitting fuel to avoid going through some of the complexities of Step 2 contemporaneous netting or potentially having to receive a major NSR permit for a project that decreases emissions.

While this rule may allow projects that produce an overall *de minimis* increase in emissions to forgo the major NSR permitting process, the EPA believes that it is equally conceivable that the rule will create an incentive for sources to adopt emissions-reducing processes and technology (that may represent control beyond what would be required for BACT or LAER) that they would not have otherwise adopted if project emissions accounting were not available. At the very least, the final rule may expedite efficiency-enhancing projects that would have otherwise require a more complex and potentially burdensome Step 2 analysis to determine that the efficiency-enhancing projects would have "netted out" or not be subject to major NSR permitting. These efficiency improvements may have collateral benefits.

The EPA also notes that projects at existing major stationary sources that are determined not to trigger major NSR permitting requirements, will, in many or most cases, be subject to minor NSR permitting requirements, regardless of the accounting procedures used in determining major NSR applicability. Minor NSR permit actions require the opportunity for public comment,[112] which provides an opportunity for stakeholders to raise potential environmental justice concerns based on the characteristics of the project and the location of the project relative to any environmental justice communities within the vicinity of the source.

Furthermore, while the EPA shares the commenter's concerns regarding the potential impacts of air pollution on environmental justice communities, the EPA notes that the NSR program is but one of many programs that address air pollution under the Clean Air Act.

In addition, and as noted elsewhere in this preamble and in the Response to Comments document for this final action, the EPA views project emissions accounting as being fully consistent with the Act and the 2002 NSR Reform Rule. Allowing for project emissions accounting will ensure that a project that itself results in a *de minimis* increase in emissions, or even a decrease in emissions, will not be subject to major NSR. As stated previously, the NSR program was designed to ensure environmental protection while allowing for economic

[111] In its preamble to the proposal, the EPA also highlighted an example of a source that could have saved four additional months of the overall permitting process timeline and $80,000 had it had the opportunity to use project emissions accounting, but there were no emissions implications tied to this example. Thus, it is conceivable that the permitted source was not beholden to BACT/LAER emissions reductions or that the source, had it been able to institute the project earlier, could have instituted emissions reductions to offset any emissions reductions that may have been attributed to the resulting BACT/LAER requirements (assuming such requirements were imposed on the source), while reducing the permitting time burden and avoiding triggering the major NSR permitting requirements.

[112] 40 CFR 51.161.

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growth by managing increases in emissions from economic development. The EPA believes that project emissions accounting properly balances those interests. In addition, as noted elsewhere, reviewing authorities have the discretion to not allow project emissions accounting and to create or maintain requirements under their SIPs that are at least as stringent as the requirements specified in the EPA's regulations.

Finally, current analytical tools and methods do not allow for a more quantitative analysis of environmental and economic costs associated with the NSR applicability test at this time. However, the EPA will consider whether any newly developed analytical tools or methods would allow for such a quantitative analysis in connection with some future NSR regulatory action.

V. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is a significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review since it raises policy issues arising from the President's priorities. Any changes made in response to OMB recommendations have been documented in the docket as required by section 6(a)(3)(E) of Executive Order 12866.

B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs

This action is considered an Executive Order 13771 deregulatory action. Before completing this rule, the EPA interpreted its NSR regulations to allow for project emissions accounting. To the extent the clarifications included in this rule influence the actions of sources and reviewing authorities to increase the use of project emissions accounting, this final rule will provide burden reduction.

C. Paperwork Reduction Act (PRA)

This action does not impose any new information collection burden under the PRA. OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control numbers 2060–0003 for the PSD and NNSR permit programs. The burden associated with obtaining an NSR permit for a major stationary source undergoing a major modification is already accounted for under the approved information collection requests.

D. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. Before this rule was finalized, the EPA interpreted its NSR regulations to allow for project emissions accounting and, as such, no increased or decreased burden is expected for sources or reviewing authorities after the finalization of the clarifications included in this rule. Furthermore, the EPA is not making the regulatory changes in this final rule mandatory for adoption and, as such, only major stationary sources located in areas where reviewing authorities decide to newly implement project emissions accounting might see a burden reduction if the consideration of emissions increases and decreases in Step 1 does not trigger further permitting requirements that may have otherwise required these major stationary sources to obtain a major NSR permit.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded federal mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local or tribal governments or the private sector.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

G. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. The EPA's NSR major modification applicability regulations in place after the 2002 NSR Reform Rule allow for the consideration of emissions increases and decreases in Step 1 of the NSR major modification applicability test and, as such, the clarifying revisions being proposed in this rule will not have exclusive tribal implications. Furthermore, the EPA is currently the reviewing authority for PSD and NNSR permits issued in tribal lands and, as such, the clarifying revisions being proposed will not impose direct burdens on tribal authorities. Thus, Executive Order 13175 does not apply to this action.

H. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

I. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. In addition, and before this rule was finalized, the EPA interpreted its NSR regulations to allow for project emissions accounting and, as such, no increased burden is expected for sources or reviewing authorities after the finalization of the clarifications included in this rule. Furthermore, the EPA is not making the regulatory changes in this final rule mandatory for adoption and, as such, only major stationary sources located in areas where state and local reviewing authorities decide to newly implement project emissions accounting might see a burden reduction if the consideration of emissions increases and decreases in Step 1 does not trigger further permitting requirements that may have otherwise required these major stationary sources to obtain a major NSR permit.

J. National Technology Transfer and Advancement Act

This rulemaking does not involve technical standards.

K. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994).

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Before this rule was finalized, the EPA interpreted its NSR regulations to allow for project emissions accounting and this action only finalized clarifying revisions to the NSR major modification applicability regulations. Further information on the Environmental Justice considerations are included in Section IV of this final action's preamble.

L. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

M. Judicial Review

Under CAA section 307(b)(1), petitions for judicial review of any nationally applicable regulation, or any action the Administrator ''finds and publishes'' as based on a determination of nationwide scope or effect must be filed in the United States Court of Appeals for the District of Columbia Circuit within 60 days of the date the promulgation, approval, or action appears in the **Federal Register**.[113] This action is nationally applicable, as it clarifies the applicability provisions that apply to Step 1 of the NSR major modification applicability test in 40 CFR 51.165, 51.166, 52, and appendix S to part 51. As a result, petitions for review of this final action must be filed in the United States Court of Appeals for the District of Columbia Circuit by January 25, 2021. Filing a petition for reconsideration by the Administrator of this final action does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review must be filed and shall not postpone the effectiveness of this action.[114]

VI. Statutory Authority

The statutory authority for this action is provided by 42 U.S.C. 7401, *et seq.*

List of Subjects

40 CFR Part 51

Environmental protection, Air pollution control.

40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference.

Andrew Wheeler,

Administrator.

For the reasons stated in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 51—REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

Subpart I—Review of New Sources and Modifications

■ 2. Section 51.165 is amended by revising paragraph (a)(2)(ii)(F) and adding paragraph (G) to read as follows:

§ 51.165 Permit requirements.

(a) * * *

(2) * * *

(ii) * * *

(F) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference for all emissions units, using the method specified in paragraphs (a)(2)(ii)(C) through (D) of this section as applicable with respect to each emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (a)(1)(x) of this section).

(G) The ''sum of the difference'' as used in paragraphs (C), (D) and (F) of this section shall include both increases and decreases in emissions calculated in accordance with those paragraphs.

* * * * *

■ 3. Section 51.166 is amended by revising paragraph (a)(7)(iv)(*f*) and adding paragraph (*g*) to read as follows:

§ 51.166 Prevention of significant deterioration of air quality.

(a) * * *

(7) * * *

(iv) * * *

(*f*) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference for all emissions units, using the method specified in paragraphs (a)(7)(iv)(*c*) through (*d*) of this section as applicable with respect to each emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(*g*) The ''sum of the difference'' as used in paragraphs (*c*), (*d*) and (*f*) of this section shall include both increases and decreases in emissions calculated in accordance with those paragraphs.

* * * * *

Subpart CC—Provisions for Implementation of the 2015 Ozone National Ambient Air Quality Standards

■ 4. Appendix S to part 51 is amended by revising section IV.I.1.(v) and adding paragraph (vi) to read as follows:

Appendix S to Part 51—Emission Offset Interpretative Ruling

* * * * *

IV. Sources That Would Locate in a Designated Nonattainment Area

* * * * *

I. *Applicability procedures.*

1. * * *

(v) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference for all emissions units, using the method specified in paragraphs IV.I.1(iii) through (iv) of this Ruling as applicable with respect to each emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph II.A.10 of this Ruling).

(vi) The ''sum of the difference'' as used in paragraphs (iii), (iv) and (v) of this section shall include both increases and decreases in emissions calculated in accordance with those paragraphs.

* * * * *

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 5. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 6. Section 52.21 is amended by revising paragraph (a)(2)(iv)(*f*) and adding paragraph (*g*) to read as follows:

§ 52.21 Prevention of significant deterioration of air quality.

(a) * * *

(2) * * *

(iv) * * *

(*f*) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference for all emissions units, using the method specified in paragraphs (a)(2)(iv)(*c*)

[113] 42 U.S.C. 7607(b)(1).

[114] 42 U.S.C. 7607(d)(7)(B).

through (*d*) of this section as applicable with respect to each emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(*g*) The ''sum of the difference'' as used in paragraphs (*c*), (*d*) and (*f*) of this section shall include both increases and decreases in emissions calculated in accordance with those paragraphs.

* * * * *

[FR Doc. 2020–25784 Filed 11–23–20; 8:45 am]

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DEPARTMENT OF TRANSPORTATION

Federal Motor Carrier Safety Administration

49 CFR Part 395

[Docket No. FMCSA–2018–0348]

RIN 2126–AC24

Hours of Service of Drivers; Definition of Agricultural Commodity

AGENCY: Federal Motor Carrier Safety Administration (FMCSA), DOT.

ACTION: Interim final rule with request for comment.

SUMMARY: FMCSA clarifies the definition of the terms ''any agricultural commodity,'' ''livestock,'' and ''non-processed food,'' as the terms are used in the definition of ''agricultural commodity'' for the purposes of the Agency's ''Hours of Service (HOS) of Drivers'' regulations. Under current regulations, drivers transporting agricultural commodities, including livestock, from the source of the commodities to a location within 150 air miles of the source, during harvest and planting seasons as defined by each State, are exempt from the HOS requirements. Furthermore, the HOS requirement for a 30-minute rest break does not apply to drivers transporting livestock in interstate commerce while the livestock are on the commercial motor vehicle. This interim final rule (IFR) clarifies the meaning of these existing definitional terms to ensure that the HOS exemptions are utilized as Congress intended.

DATES: This IFR is effective December 9, 2020. You must submit comments on or before December 24, 2020.

Petitions for Reconsideration of this IFR must be submitted to the FMCSA Administrator no later than December 24, 2020.

ADDRESSES: You may submit comments identified by docket number FMCSA–2018–0348 using any one of the following methods:

* *Federal eRulemaking Portal:* Go to *http://www.regulations.gov/#!docketDetail;D=FMCSA-2018-0348*. Follow the online instructions for submitting comments.

* Fax: (202) 493–2251.

* *Mail:* Dockets Operations, U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590–0001.

* *Hand delivery:* Same as mail address above, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: Mr. Richard Clemente, Driver and Carrier Operations Division, FMCSA, 1200 New Jersey Avenue SE, Washington, DC 20590–0001, (202) 366–4325, *MCPSD@dot.gov*. If you have questions on viewing or submitting material to the docket, contact Dockets Operations, (202) 366–9826.

SUPPLEMENTARY INFORMATION: This IFR is organized as follows:

I. Public Participation and Request for Comments
- A. Submitting Comments
- B. Viewing Comments and Documents
- C. Privacy Act

II. Executive Summary
III. Legal Basis for the Rulemaking
IV. Background
V. Discussion of Interim Final Rule
VI. Questions
VII. International Impacts
VIII. Section-by-Section Analysis
IX. Regulatory Analyses
- A. E.O. 12866 (Regulatory Planning and Review), E.O. 13563 (Improving Regulation and Regulatory Review), and DOT Regulations
- B. E.O.13771 (Reducing Regulation and Controlling Regulatory Costs)
- C. Congressional Review Act
- D. Regulatory Flexibility Act (Small Entities)
- E. Assistance for Small Entities
- F. Unfunded Mandates Reform Act of 1995
- G. Paperwork Reduction Act
- H. E.O. 13132 (Federalism)
- I. Privacy
- J. E.O. 13175 (Indian Tribal Governments)
- K. Environment

I. Public Participation and Request for Comments

A. Submitting Comments

If you submit a comment, please include the docket number for this IFR (FMCSA–2018–0348), indicate the specific section of this document to which your comment applies, and provide a reason for each suggestion or recommendation. You may submit your comments and material online or by fax, mail, or hand delivery, but please use only one of these means. FMCSA recommends that you include your name and a mailing address, an email address, or a phone number in the body of your document so that FMCSA can contact you if there are questions regarding your submission.

To submit your comment online, go to: *http://www.regulations.gov/#!docketDetail;D=FMCSA-2018-0348*, click on the ''Comment Now!'' button, and type your comment into the text box on the following screen. Choose whether you are submitting your comment as an individual or on behalf of a third party and then submit.

If you submit your comments by mail or hand delivery, submit them in an unbound format, no larger than 8½ by 11 inches, suitable for copying and electronic filing. If you submit comments by mail and would like to know that they have reached the facility, please enclose a stamped, self-addressed postcard or envelope.

FMCSA will consider all comments and material received during the comment period and may change this IFR based on your comments. FMCSA may issue a final rule at any time after the close of the comment period.

Confidential Business Information

Confidential Business Information (CBI) is commercial or financial information that is both customarily and actually treated as private by its owner. Under the Freedom of Information Act (FOIA, 5 U.S.C. 552), CBI is exempt from public disclosure. If your comments responsive to this IFR contain commercial or financial information that is customarily treated as private, that you actually treat as private, and that is relevant or responsive to this IFR, it is important that you clearly designate the submitted comments as CBI. Please mark each page of your submission that constitutes CBI as ''PROPIN'' to indicate it contains proprietary information. FMCSA will treat such marked submissions as confidential under the FOIA, and they will not be placed in the public docket of this IFR. Submissions containing CBI should be sent to Mr. Brian Dahlin, Chief, Regulatory Analysis Division, Federal Motor Carrier Safety Administration, 1200 New Jersey Avenue SE, Washington DC 20590. Any comments that FMCSA receives which are not specifically designated as CBI will be placed in the public docket for this rulemaking.

B. Viewing Comments and Documents

To view comments, as well as any documents mentioned in this preamble as being available in the docket, go to *http://www.regulations.gov/#!docketDetail;D=FMCSA-2018-0348*

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E. SCOTT PRUITT
ADMINISTRATOR

March 13, 2018

MEMORANDUM

SUBJECT: Project Emissions Accounting Under the New Source Review Preconstruction Permitting Program

FROM: E. Scott Pruitt

TO: Regional Administrators

In accordance with presidential priorities for streamlining regulatory permitting requirements for manufacturing, and in line with my prior recognition that "opportunities exist to simplify" the New Source Review process and thereby "achieve meaningful NSR reform,"[1] thee U.S. Environmental Protection Agency has been undertaking an assessment of the agency's implementation of the preconstruction permitting requirements under the NSR provisions of the Clean Air Act. As part of this assessment, the EPA has identified certain elements of the NSR regulations and associated EPA policies that have been sources of confusion and uncertainty.[2]

One such element that has given rise to uncertainty among both permitting authorities and stakeholders alike is whether emissions decreases from a proposed project at an existing major stationary source may be taken into account under Step 1 of the major modification applicability process in the EPA NSR regulations. The purpose of this memorandum is to communicate the EPA's interpretation that its current NSR regulations provide that emissions decreases as well as increases are to be considered at Step 1 of the NSR applicability process, provided they are part of a single project. The EPA has at times indicated that the relevant provisions of the NSR regulations preclude the consideration of emissions decreases at Step 1, but for the reasons discussed below, the agency will no longer apply any such interpretation reflected in prior statements on this issue.[3]

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[1] *See* Final Report on Review of Agency Actions that Potentially Burden the Safe, Efficient Development of Domestic Energy Resources Under Executive Order 13783 (Oct. 25, 2017) at 3.

[2] *See, e.g.* "New Source Review Preconstruction Permitting Requirements: Enforceability and Use of the Actual-to-Projected-Actual Applicability Test in Determining Major Modification Applicability" (Dec. 7, 2017).

[3] Thus, for example, the EPA no longer subscribes to the reading of the NSR regulations that is reflected in the Letter from Barbara A. Finazzo, U.S. EPA Region 2 to Kathleen Antoine, HOVENSA, LLC, "Re: HOVENSA Gas Turbine

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Background

Under EPA regulations, the process for determining whether a project at an existing major stationary source triggers the requirement to obtain an NSR permit is a two-step process. Step 1 requires a determination of whether the proposed project, by itself, is projected to result in a significant emissions increase. If such an increase is projected to occur, the process moves to Step 2. Under Step 2, an evaluation is made as to whether the project will result in a significant *net* emissions increase, considering any other increases and decreases in actual emissions at the source that are contemporaneous with the particular project and are otherwise creditable. The EPA has generally referred to Step 2 as "netting" or "contemporaneous netting."

In the past, the EPA has sometimes described the consideration of both increases and decreases in emissions under Step 1 of the NSR applicability process as "project netting." The EPA now recognizes that using the term "project netting" at Step 1 has resulted in confusion among stakeholders, permitting authorities and within the EPA itself. A more appropriate term to characterize the consideration of a proposed project's emissions increases and decreases at Step 1 is "project emissions accounting." In the context of Step 1, the term "netting" is misplaced, insofar as "netting" more properly describes looking at those *other* projects that may have been or will be undertaken at a given facility over the contemporaneous period – i.e. an evaluation that takes place under Step 2. In contrast, "project emissions accounting" more accurately captures what Step 1 of the NSR applicability process is really all about – i.e. taking account of the true emissions impacts of the project itself.

The EPA believes that those prior agency statements that interpreted the NSR regulations as precluding project emissions accounting have had the practical effect of preventing certain projects from going forward and significantly delaying others, even though those projects would not have resulted in a significant emissions increase.[4] The EPA recognizes that because of the inherent complexities associated with doing multi-year contemporaneous netting under Step 2 at a large facility,[5] some companies may have been dissuaded from undertaking some projects. As a consequence, the EPA's lack of clarity in this matter likely foreclosed projects with the potential to make production more efficient across a wide variety of industrial sectors. Such efficiencies can result in reduced emissions, even while production is maintained or expanded. The interpretation provided here is consistent with the language of the NSR regulations and should result in sounder regulatory outcomes.

Nitrogen Oxides (GT NOx) Prevention of Significant Deterioration (PSD) Permit Application- Emission Calculation Clarification" (March 30, 2010) (March 30 HOVENSA Letter).

[4] *See, e.g.* National Mining Association Response to Request for Comments on Regulations Appropriate for Repeal, Replacement, or Modification Pursuant to Executive Order 13777, 82 FR 17,793 (Apr. 13, 2017), at 3-4, EPA-HQ-2017-0190-37770; Testimony of Paul Noe for Am. Forest & Paper Ass'n and Am. Wood Council, House Comm. on Energy & Commerce, Subcomm. on Env't, Oversight Hearing on "New Source Review Permitting Challenges for Manufacturing and Infrastructure," at 2, 5, 7-8 (Feb. 14, 2018) ("Noe Testimony").

[5] *See, e.g.* Noe Testimony at 7-8.

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Relevant CAA and Regulatory Provisions

The NSR provisions of the CAA and the EPA's implementing regulations require that a preconstruction permit be obtained prior to beginning (1) the construction of a new major stationary source or (2) a "major modification" to an existing major stationary source. In general, preconstruction permits for sources emitting pollutants for which the area is designated attainment or unclassifiable and for other pollutants regulated under the major source program are called prevention of significant deterioration (PSD) permits. Permits for major sources emitting nonattainment pollutants and located in nonattainment areas are referred to as nonattainment NSR (NNSR) permits. The preconstruction permitting program, including the PSD and the NNSR permitting programs, is known as the NSR program.

The CAA contains no statutory definition of the term "major modification." The CAA does, however, define the term "modification" – i.e. "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." 42 U.S.C. § 7411(a)(4); CAA § 111(a)(4).[6] Reflecting the fact that the preconstruction review provisions of the CAA's PSD and nonattainment area permitting programs are phrased in terms of the construction or modification of a "major emitting facility" (under the PSD program) and of a "major stationary source" (under the nonattainment program),[7] The EPA's implementing regulations have from their earliest days been framed in terms of how one goes about determining whether a particular activity at an existing "major stationary source" will be deemed to be a "major modification."[8] The EPA regulations specify that one determines whether a modification is "major" based on whether the modification results in an increase of emissions above specified rates defining whether the increase is "significant" (or greater than a *de minimis* amount).[9]

A project[10] constitutes a major modification for a regulated NSR pollutant if (and only if) it would result in two types of emissions increases – i.e. a significant emissions increase

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[6] This definition of "modification," originally enacted by Congress in 1970 as part of the New Source Performance Standards (NSPS) program, was incorporated by reference for purposes of the newly enacted PSD and nonattainment programs by the Clean Air Act Amendments of 1977. *See* 42 U.S.C. § 7479; CAA § 169(C) ("The term 'construction' when used in connection with any source or facility, includes the modification (as defined in section 7411(a) of this title) of any source or facility."); 42 U.S.C. 7501 (4); CAA § 171 (4) ("The terms 'modifications' and 'modified' mean the same as the term 'modification' as used in section 7411(a)(4) of this title.")

[7] 42 FR 57479, 57480 (Nov. 3, 1977).

[8] *See*, e.g. 40 CFR § 52.21(a)(2) (1978).

[9] *See*, e.g. 40 CFR § 52.21(a)(2) (2017). The EPA adopted this current approach after a court rejected the EPA's initial attempt to determine whether a modification was "major" based on the thresholds of 100 and 250 tons per year from the statutory definition of "major emitting facility." *Alabama Power v. Costle*, 636 F.2d 323, 399-400 (D.C. Cir. 2012); 44 FR 51924, 51937 (Sept. 9, 1979); 45 FR 52676, 52705 (Aug. 7, 1980).

[10] A "project" is defined as "a physical change in, or change in the method of operation of, an existing major stationary source." 40 CFR § 52.21(b)(52).

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(determined at Step 1), and a significant net emissions increase (determined at Step 2).[11] *See*, e.g. 40 CFR § 52.21(a)(2)(iv)(*a*).[12] These NSR applicability procedures, adopted as part of the 2002 NSR Reform rule,[13] codified a prior EPA practice of looking first at whether any emissions increase that may result from the project itself would be significant before evaluating whether there would be a significant "net emissions increase" from the major stationary source as a whole.

> The regulations further specify that the particular procedure for calculating whether a proposed project would by itself result in a significant emissions increase depends upon the type of emissions units that would be included in the proposed project.[14] *See* 40 CFR § 52.21(a)(2)(iv)(b). These different procedures are required because, under the NSR regulations, the specific requirements for determining both the "baseline actual emissions" and the post-change "projected actual emissions" for existing emissions units are different than the requirements for determining the "baseline actual emissions" and the post-change "potential to emit" for new emissions units.
>
> As relevant here, the NSR regulations currently provide as follows:
>
> § 52.21 Prevention of significant deterioration of air quality.
>
> (a)(1) * * * *
>
> (2) *Applicability procedures.* (i) The requirements of this section apply to the construction of any new major stationary source (as defined in paragraph (b)(1) of this section) or any project at an existing major stationary source in an area

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[11] The net emissions increase is calculated as the sum of the emissions increase attributable to the particular project, calculated pursuant to 40 CFR § 52.21(a)(2)(iv), and any other increases and decreases in actual emissions at the major stationary source that are contemporaneous and otherwise creditable. *See* 40 CFR § 52.21(b)(3). Notwithstanding the interpretation of Step 1 communicated in this memorandum, source-wide netting (i.e. Step 2) will continue to have an important role in the NSR applicability process. For example, source-wide netting always will be needed, as appropriate, to allow for consideration of emissions associated with past projects within the contemporaneous period.

[12] This memorandum cites certain provisions in the federal PSD regulations at 40 CFR § 52.21(a)(2). The other NSR regulations, including 40 CFR § 51.166(a)(7), 40 CFR § 51.165(a)(2), and Appendix S of Part 51 (Part IV, Subpart I), contain analogous definitions and requirements, and the interpretation set forth in this memorandum also applies to those analogous provisions. However, there are certain modification provisions under the Title I, Subpart D of the CAA and the EPA nonattainment NSR regulations that apply to certain nonattainment area classifications (*see*, e.g. CAA § 182(e)(2); 40 CFR Part 51, Appendix S II.A.5.(v)). This memorandum does not address those specific modification provisions in the Act or the EPA regulations for nonattainment areas, and, thus, does not communicate any EPA view regarding interpretation of those provisions.

[13] In 2002, the EPA issued a final rule that revised the regulations governing the major NSR program. 67 FR 80186 (Dec. 31, 2002). The agency refers generally to these rule provisions as the "NSR Reform rule."

[14] "Emissions unit" is defined, in relevant part, as "any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit as defined in paragraph (b)(31) of this section." 40 CFR § 52.21(b)(7). An "emissions unit" can be either a "new" unit or an "existing" unit, with a "new" unit being further defined as "any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated." *Id.* at § 52.21(b)(7)(*i*). An "existing emissions unit" is any unit that is not a "new emissions unit." *Id.* at § 52.21(b)(7)(*ii*).

designated as attainment or unclassifiable under sections 107(d)(1)(A)(ii) or (iii) of the Act.

* * * *

(iv)eThe requirements of the program will be applied in accordance with thee principles set out in paragraphs (a)(2)(iv)(*a*) through (*f*) of this section.e

* * * *

(b) The procedure for calculating (before beginning actual construction) whether a significant emissions increase (i.e. the first step of the process) will occur depends upon the type of emissions units being modified, according to paragraphs (a)(2)(iv)(*c*) through (f)of this section. The procedure for calculating (before beginning actual construction) whether a significant net emissions increase will occur at the major stationary source (i.e. the second step of the process) is contained in the definition in paragraph (b)(3) of this section. Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.

(c) *Actual-to-projected-actual applicability test for projects that only involve existing emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions (as defined in paragraph (b)(41) of this section) and the baseline actual emissions (as defined in paragraphs (b)(48)(i) and (ii) of this section), for each existing emissions unit, equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(d) *Actual-to-potential test for projects that only involve construction of a new emissions unit(s).* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit (as defined in paragraph (b)(4) of this section) from each new emissions unit following completion of the project and the baseline actual emissions (as defined in paragraph (b)(48)(iii) of this section) of these units before the project equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

(e) [Reserved][15]

[15] While now designated as "reserved," what had been clause (*e*) of 40 CFR § 52.21(a)(2)(iv) was promulgated as part of the 2002 NSR Reform rule. As originally promulgated, clause (*e*) read as follows:

> (*e*) *Emissions test for projects that involve Clean Units.* For a project that will be constructed and operated at a Clean Unit without causing the emissions unit to lose its Clean Unit designation, no emissions increase is deemed to occur.

See 67 FR 80275. The Clean Unit provision of the 2002 NSR Reform rule was subsequently held to be unlawful and vacated by the U.S. Court of Appeals for the D.C. Circuit in *State of New York v. EPA*, 413 F.3d 3, 38-40 (D.C. Cir.

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> (*f*) *Hybrid test for projects that involve multiple types of emissions units.* A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the method specified in paragraphs (a)(2)(iv)(*c*) through (*d*) of this section as applicable with respect to each emissions unit, for each type of emissions unit equals or exceeds the significant amount for that pollutant (as defined in paragraph (b)(23) of this section).

40 CFR § 52.21(a)(2)(iv)(b)-(f).

The EPA's Interpretation of the NSR Applicability Provisions

Based on the reconsideration of some previous conclusions and an examination of the regulations as a whole, the EPA now interprets the provisions set forth in 40 CFR § 52.21(a)(2)(iv)(*c*) through (iv)(*f*) as providing that any emissions *decreases* that may result from a given proposed project are to be considered when calculating at Step 1 whether the proposed project will result in a significant emissions increase. This interpretation is grounded in the principle that the "plain language of the CAA indicates that Congress intended to apply NSR to *changes that increase actual emissions*." *State of New York v. EPA*, 413 F.3d at 40 (emphasis added). Central to the CAA's definition of "modification" is that there must be a causal link between the physical or operational change at issue – i.e. the "project" – and any change in emissions that may ensue. In other words, it is necessary to account for the full and direct effect of the proposed change itself. Accordingly, at the very outset of the process for determining whether NSR may be triggered, the EPA should give attention to not only whether emissions may increase from those units that are part of the project but also whether emissions may at the same time decrease at other units that are also part of the project.

The use of the phrase "sum of the difference" in clauses (*c*) and (*d*) of 40 CFR § 52.21(a)(2)(iv) makes this clear. The "difference" between a unit's projected actual emissions or potential to emit (following the completion of the project) and its baseline actual emissions (prior to the project) may be either a positive number (representing a projected increase) or a negative number (representing a projected decrease). In either case, the values that result from "summing" the "difference" are to be taken into consideration at Step 1 in determining the emissions impact of the project.

Some have argued that, in the case of projects involving only new units, the "sum of the difference" could never include a decrease in emissions, because the applicable test compares the potential to emit following the project to pre-project baseline actual emissions, which are equal to

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2005). Thereafter, all of the regulatory language related to the Clean Unit provision, including clause (*e*) of 40 CFR § 52.21(a)(2)(iv), was stricken from the NSR Reform rule. *See* 72 FR 32526, 32528 (June 13, 2007). Also affected by the D.C. Circuit's vacatur was certain language of clause (*f*) of 40 CFR § 52.21(a)(2)(iv) as it had originally been promulgated in 2002. Struck from clause (*f*) was a final sentence that provided: "For example, if a project involves both an existing unit and a Clean Unit, the projected increase is determined by summing the values determined using the method specified in paragraph (a)(2)(iv)(*c*) of this section for the existing unit and using the method specified in paragraph (a)(2)(iv)(*e*) of this section for the Clean Unit." *See* 67 FR 80275; 72 FR 32529.

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zero.[16] What this argument overlooks is that the NSR regulations define a "new unit" as "any emissions unit that is (or will be) newly constructed and that has existed *for less than 2 years* from the date such emission unit first operated" 40 CFR § 52.21(b)(7)(i) (emphasis added), and for a new unit "the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero," and "thereafter, for all other purposes, shall equal the unit's potential to emit." 40 CFR § 52.21(b)(48)(iii). Therefore, following initial construction or permitting, a "new unit" (i.e. one that has existed for less than two years since it first operated) could, as the result of a particular project, experience a decrease in potential emissions – that is, the "sum of the difference" could be a negative number – if that project involved, for instance, the installation of controls on the unit, resulting in a decreasee in the unit's potential to emit.[17e]

The phrase "sum of the difference" does not appear in clause (*f*) of 40 CFR § 52.21(a)(2)(iv). This omission, and the fact that clause (*f*) speaks of the "sum of the emissions increases," led the EPA to say in a September 2006 notice of proposed rulemaking that this "challenges whether an emissions increase at an individual emissions unit can be a negative number." *See* 71 FR 54249 (Sept. 14, 2006). While the EPA went on to say that it was "reasonable to conclude that a source can perform project netting for hybrid [projects] as well," the agency also indicated that the "current rule . . . would not allow a source to include reductions from units that are part of the project until Step 2 of the calculation." *Id.* It was on that basis that the EPA proposed new regulatory language that was directed at making it explicit that emissions decreases as well as increases would be accounted for at Step 1 for projects involving both existing and new units. *Id.* at 54252.

Based on a more thorough consideration of the surrounding context in the regulations, the EPA finds that the negative inference which the agency drew in 2006 from the fact that the phrase "sum of the difference" is absent from clause (*f*) was unwarranted.[18] Other language in clause (*f*)

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[16] It was on this basis that the EPA previously said that, because the "sum of the difference" for a project that only involves new emissions units must entail summing only emissions increases, this result should also inform the reading of the "sum of the difference" as the phrase is applied to projects involving only existing units, leading to the conclusion that taking account of emissions decreases at Step 1 is not permitted at all. *See* March 30 HOVENSA Letter at 5. As was previously noted, the EPA no longer subscribes to the reading of the NSR regulations reflected in the March 30 HOVENSA Letter.

[17] In its March 30 HOVENSA Letter, the EPA also stated that "EPA would not have needed to provide a special provision and unique rationale for the replacement unit rule if EPA had intended to allow project netting under the 2002 NSR Reform Rule." March 30 HOVENSA Letter at 4. But this does not follow. Absent the provision, a replacement unit would be deemed a new emissions unit to which the actual-to-potential test would apply instead of the actual-to-projected-actual test applicable to existing units (including replacement units). This difference between the two applicability tests remains regardless of whether emissions decreases are accounted for at Step 1.

[18] This negative inference previously led the EPA to adopt the view that this provision did not allow "project netting," 71 FR at 54249, and thus that it was necessary to propose an amendment to 40 CFR § 52.21(a)(2)(iv)(*f*) to allow project emission accounting for hybrid projects. 71 FR at 54251. Since the EPA no longer considers the negative inference to be warranted, the agency also does not believe it is necessary to finalize the proposed 2006 revision before project emissions accounting can be conducted in Step 1 of the NSR applicability analysis for hybrid projects. However, the EPA is not taking action at this time to withdraw the project netting elements of the 2006 notice of proposed rulemaking. The EPA is still evaluating whether a revision of the text of 40 CFR § 52.21(a)(2)(iv)(*f*) is desirable to provide additional clarity on this issue.

indicates that emissions decreases are also to be accounted for. Clause (*f*) specifically provides that the "sum of the emissions increases for each emissions unit" is to be calculated *after* the specific impact of the proposed project has been ascertained with respect to each type of unit involved, "using the method specified in paragraphs (a)(2)(iv)(*c*) through (*d*) of this section *as applicable with respect to each emission unit*." (emphasis added). That is, for a project involving both existing and new units, this accounting is to be done on a unit type-by-unit type basis, in which both emissions decreases (if any) and emissions increases (if any) are to be taken into consideration.

Moreover, the history of this provision in the regulations indicates that the EPA originally intended that project emissions accounting be allowed at Step 1 for projects involving different types of units. The concluding "For example . . ." sentence that had originally been part of clause (*f*) but which had been stricken (for unrelated reasons) when the Clean Unit provision was vacated, *see* note 15 above, illustrates the agency's intention. That sentence provided that, where a proposed project involves different types of units, the determination whether there is a projected increase is to be made by "summing the *values determined using* the method specified in paragraph (a)(2)(iv)(*c*) of this section for the existing unit and using the method specified in paragraph (a)(2)(iv)(*e*) of this section for the Clean Unit." (emphasis added). If one were to substitute "new unit" for "Clean Unit" and "paragraph (a)(2)(iv)(*d*)" for "paragraph (a)(2)(iv)(*e*)," by way of providing a different "example," the point remains. Since the "values" derived from calculating the "sum of the difference" with respect to both existing units and new units could be a negative number, the language used in clause (*f*) – "sum of the emissions increases" – presents no "challenge" to the use of project emissions accounting, i.e. taking account of emissions decreases as well as emissions increases, under the current regulatory language pertaining to projects that involve both existing and new units.

The EPA does not interpret the existing regulations as requiring that a decrease be creditable or enforceable as a practical matter in order to be considered at Step 1. The issue of whether an emissions decrease is creditable and enforceable is relevant to Step 2, but not to Step 1. Regarding this, in the 2002 NSR Reform rule, the EPA expressly declined to adopt a requirement under which a source's post-project projected actual emissions would have become an enforceable emission limitation. Such an approach had previously been suggested by the EPA, but the agency ultimately rejected it. *See* 67 FR 80193, 80197. The same reasoning that underpinned the 2002 NSR Reform rule's treatment of projected actual increases applies equally to projected emissions decreases at Step 1. One exception to this is where an emissions decrease is calculated using the potential to emit of a unit after the project. In such a case, the requirements of 40 CFR § 52.21(b)(4) would continue to apply.

The EPA also promulgated, as part of its adoption of provisions addressing the use of the "projected actual emissions" methodology, provisions pertaining to the tracking, documenting, and, under certain circumstances, the reporting of post-project emissions increases. *See*, e.g. 40 CFR §§ 52.21(b)(41), 52.21(r)(6). Those provisions would impose on sources the same obligations with respect to emissions decreases taken account of at Step 1. Given this, the EPA should not treat projected increases and projected decreases differently at Step 1, by requiring that decreases

US EPA ARCHIVE DOCUMENT

be "creditable" and "enforceable," as would be the case with contemporaneous decreases accounted for at Step 2.[19]

Finally, it is important to point out that project emissions accounting, as described above, is a calculation that is done in conjunction with ascertaining, prior to beginning actual construction, the applicability of NSR to a particular project at a source that the owner/operator is itself *proposing* to undertake. In this regard, the EPA recognizes that as a general matter, the source itself is responsible for defining the scope of its own "project," subject to the understanding that the source cannot seek to circumvent NSR by characterizing the proposed project in a way that would separate into multiple projects those activities that, by any reasonable standard, constitute a single project. Subject to the equivalent understanding that it might be possible to circumvent NSR through some wholly artificial grouping of activities, the EPA does not interpret its NSR regulations as directing the agency to preclude a source from reasonably defining its proposed project broadly, to reflect multiple activities. The EPA will speak more to this issue in planned upcoming action on "project aggregation."

* * * *

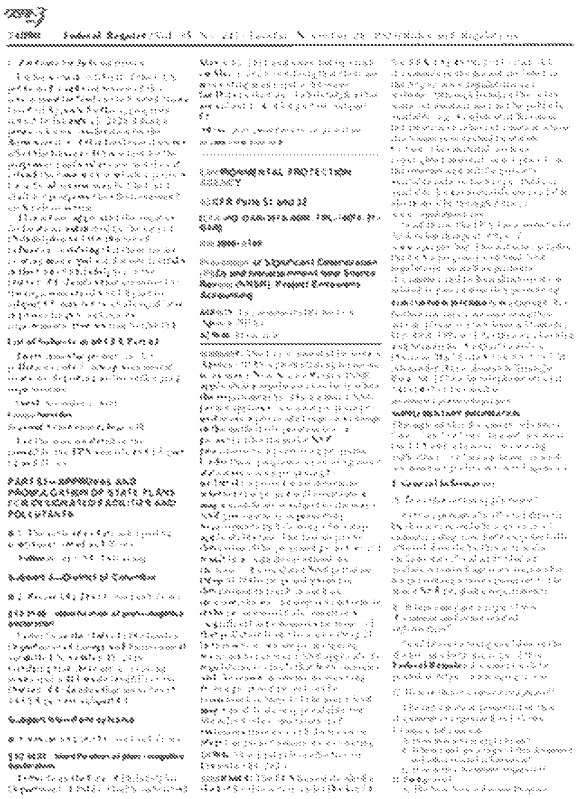
The EPA Regional Offices should send this memorandum to states within their jurisdiction. For any questions concerning this memorandum, please contact Anna Marie Wood in the Office of Air Quality Planning and Standards at (919) 541-3604 or *wood.anna@epa.gov*.

[19] In the September 2006 notice of proposed rulemaking, the EPA had proposed to adopt regulatory language that specified, for the purposes of what was then termed "project netting," that emissions decreases must be creditable or otherwise enforceable as a practicable matter. *See* 71 FR 54252. At that time, the EPA provided no explanation why it considered such a requirement to be either necessary or warranted, and the agency now recognizes that other provisions in existing regulations serve to alleviate concerns that projected emissions decreases would escape the same tracking, documentation and reporting requirement applicable to projected emissions increases. As discussed in footnote 18, the EPA is not withdrawing the September 2006 proposal at this time, pending further consideration of whether a revision of the regulatory text is desirable to provide further clarity.

US EPA ARCHIVE DOCUMENT

EPA Issues "Project Emissions Accounting" Rule

On October 22, 2020, Andrew Wheeler, EPA Administrator, signed the final rule adopting the "project emissions accounting" approach to Step1 of the Prevention of Significant Deterioration (PSD) and major nonattainment area new source review (NNSR) programs. The final rule provides that both increases and decreases resulting from a proposed project can be considered in Step 1 of the major NSR modification applicability test, provided that all changes are part of the same "project" as EPA had defined that term in the 2018 reconsideration of "project aggregation."



ANALYSIS

The EPA states that the 2002 NSR Reform Rule codified the prior practice of treating "major modification" applicability as a two step process: looking first at whether any emissions increase that would result from the project itself is "significant" before evaluating whether there would be significant "net emissions increase" from the major stationary source. An increase is significant under either step if it would exceed any of the pollutant-specific "significant emission rates" (SERs) listed in the applicable PSD or NNSR regulation. For other unlisted regulated NSR pollutants, "any" increase is significant.

For Step 1, the EPA stated that for "new" units, one looks at the difference between pre- and post-project emissions on a potential to emit basis, while for "existing" units one can compare the post-project "projected actual emissions" or potential to emit to the pre-project "baseline actual emissions" to determine whether it is significant. Based on this comparison, the source determines whether the change in the project is "significant." If the project is not significant, it is not subject to PSD or NNSR.

If the project increase is significant, then the source proceeds to Step 2, in which the source considers all "contemporaneous" emissions increases and decreases which includes (i) the increase from the project; (ii) any other increases and decreases at the major stationary source that are both contemporaneous and otherwise creditable. Under the EPA rule (and most states), contemporaneous means five years before the date construction on the project commences and the date that the increase from the project occurs. An increase or decrease is creditable only if it has not previously been relied upon by the permitting authority, it represents a "real" increase or decrease in emissions, and, if a decrease, it is enforceable as a practical matter on and after the

date the project emissions increase occurs. In NNSR, the source must also show that the emissions decrease was not relied upon for demonstrating attainment or reasonable further progress.

In March 2018, the EPA issued a memorandum stating that "emissions decreases as well as increases are to be considered at Step 1 of the NSR applicability process, provided that they are part of a single project." In its memorandum, the EPA acknowledged that the rule language for "hybrid" projects was not as clear on allowing decreases as well as increases as the rule language for "new" and "existing" emission units. Accordingly, in its proposed rule, the EPA proposed to replace "sum of the emissions increase" for hybrid projects with "sum of the difference" and, in the case of hybrid projects, to "sum the difference" of "all emission units" rather than for each emission unit.

In the final preamble, the EPA stated:

The EPA believes that allowing for consideration of both emissions increases and decreases from a project is consistent with congressional intent for the PSD and NNSR preconstruction permitting programs to cover existing sources only when they undertake projects which result in a non-de minimis increase in emissions. If the full scope of emissions changes from a project were not considered in Step 1, the regulations could subject a project to major NSR when the actual effect of that project would be to reduce emissions or result in a de minimis increase in emissions, which would be contrary to congressional intent for this program. The EPA sees little policy support for such an outcome.

Page 17-18, pre-publication draft.

The EPA addressed several challenges by commenters to its rule rationale, including:

- "The EPA is making a 'project exemption" similar to the equipment replacement rule rejected by D.C. Circuit." The EPA rejected this argument, stating that it is merely clarifying the current test, not creating an exemption, noting that it merely applies the same language to "hybrid" projects that previously applied to "new" or "existing" projects.
- "The EPA fails to require that 'any' physical change or change in the method of operations" be addressed because old decreases could be included. The EPA stated that this is not the case because the "substantially related" test for project it adopted as part of the 2018 project aggregation reconsideration requires that all parts of the project be sufficiently "contemporaneous" in time to be "substantially related."
- "The EPA has failed to require enforceable emissions reductions." The EPA disagreed, arguing that separate enforceability is required for Step 2 netting because it is an unrelated project that is being used to avoid PSD or NNSR review, while in Step 1 emissions accounting, it is the same project. The EPA also reiterated that if a project subsequently exceeds the SERs, the source may be liable for NSR circumvention.
- "The EPA's proposal makes Step 2 superfluous." The EPA disagreed, noting that Step 2 is required to count emissions decreases from unrelated projects.
- "The EPA's action gives up benefits under the Clean Air Act and is not justified as an exercise of its *de minimis* authority." EPA stated that it is not exercising *de minimis* authority, merely giving effect to determining when a project is not *de minimis*.

Because of the importance of defining the "project" under the foregoing arguments, the EPA reaffirmed its decision in the 2018 project aggregation reconsideration that only projects that are "substantially related" may be considered for inclusion together in Step 1. This requires a consideration of the technical and economic relationship of the various components of the project.

The EPA next took up concerns that the "reasonable possibility" recordkeeping requirements were not sufficient to prevent circumvention of NSR requirements given the consideration of decreases in Step 1. Commenters stated that sources would just project emissions decreases to come below the 50% threshold and would proffer explanations when the emissions were different that projected that place an "undue burden" on permitting authorities to review. The EPA rejected these comments as not persuasive and little more than commenters' belief that sources would circumvent. The EPA noted that reasonable possibility monitoring is required if the project exceeds 50% and that there is ample recordkeeping under state minor NSR programs and Title V to identify problems.

Finally, the EPA determined, based on comments, that it will require adoption of this rule by permitting authorities that exercise "delegated" program authority, but that SIP-
authorized programs do not need to adopt it.

COMMENTARY

The final rule, which formalizes EPA's "project emissions accounting" approach that allows emissions increases and decreases from a "project" to be considered in Step 1 is an important step in returning the NSR programs to a more common sense approach and eliminating the "traps for the unwary" which have long characterized this program. The new approach allows sources to build in controls as part of the project to keep from triggering NSR requirements. It is understandable by source management and easier to implement in the corporate world where money can be planned for controls to achieve a project, as opposed to the former approach where controls did not count and additional controls, often on equipment not associated with the project, had to be added. In this respect the rule is welcome.

As a practical matter, it is unfortunate that the EPA allowed itself to be drug into the "project" definition morass further by commenters. Many state and local permitting authorities have preferred to aggregate many projects into fewer PSD or NNSR permits to reduce the permitting burden on both them and the source. The effect of this approach has been to require PSD or NNSR permits as more increases were involved. This practice may be in jeopardy. One can easily envision a future where environmental groups comment on applications to try to "redefine" projects so that they can argue that parts of the project should be excluded and hence the project rejected and redefined and resubmitted, leading to delay for source and redundant application of agency resources. Under this line of legal thinking, it may not even matter whether exclusion of part of a project would have changed the permitting decision because it would be a procedural error. One hopes that EPA and authorized states will reject such efforts that lead to no environmental benefit, just delay.

Emission Factor Search

WebFIRE contains the EPA's emissions factors for criteria and hazardous air pollutants (HAP) for industrial and non-industrial processes. To retrieve emissions factors, select one or more search terms from the dropdown menus below then click on the "Submit Search" button at the bottom of the page.

For the Source Classification Code (SCC), Pollutant, and Control Device categories, clicking the category of interest and then clicking the link to "Select options" opens a dropdown menu of the available search terms for that category. You can choose one or more terms of interest by clicking on the check box to the left of the dropdown menu. The "Select options" link also opens a filter box that allows you to limit the items shown in the dropdown menu to only those that contain your filter box entry somewhere in the description of the term. For example:

- Entering "101001" in the SCC filter box reduces the dropdown menu to only those items that contain "101001" in the SCC description (e.g., 10100101-External Combustion Boilers; Electric Generation; Anthracite Coal; Pulverized; Boiler).
- Entering "10" in the Pollutant filter box reduces the dropdown menu to only those items that contain "10" in the pollutant description (e.g., Polonium 210).
- Entering "ammonia" in the Control Device filter box reduces the dropdown menu to only those items that contain "ammonia" in the control device description (e.g., ammonia injection).

Clicking on the "Choose a section from AP-42" link opens the dropdown menu showing the sections of EPA's AP-42 (*Compilation of Air Pollutant Emissions Factors*) available for refining your search. For example, selecting "Bituminous and Subbituminous Coal Combustion" will retrieve only the emissions factors corresponding to AP-42 Chapter 1 (External Combustion Sources), Section 1.1 (Bituminous and Subbituminous Coal Combustion). You can select multiple AP-42 sections by holding down the "Ctrl" button on your keyboard.

Source Classification Code

Select options

Filter: coke oven gas

Pollutant

Control Device

Choose a section from AP-42

Choose to include Revoked Factors

R012566

Expand all Collapse all

Submit Search Reset

Discover.
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without revoked factor

Emission Factor Results

17 factors found.

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT Carbon monoxide NEI CO CAS 630-08-0
Control(s): UNCONTROLLED
Emission Factor -- 1.84E+01 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- U Emissions Factors Applicability

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT Nitrogen oxides (NOx) NEI NOX CAS
Control(s): UNCONTROLLED
Emission Factor -- 8.00E+01 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- U Emissions Factors Applicability

8.00 E +01
= 8 x 10^1
= 8 x 10
= 80

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT PM, condensable NEI PM-CON CAS
Control(s): UNCONTROLLED
Emission Factor -- 5.70E+00 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- E Emissions Factors Applicability

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT PM, filterable NEI PM-FIL CAS
Control(s): UNCONTROLLED
Emission Factor -- 6.20E+00 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- U Emissions Factors Applicability

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT PM10, filterable NEI PM10-FIL CAS
Control(s): UNCONTROLLED

Emission Factor -- 4.35E+00 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- U Emissions Factors Applicability

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT PM10, primary NEI PM10-PRI CAS
Control(s): UNCONTROLLED
Emission Factor -- 1.01E+01 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- U Emissions Factors Applicability

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT PM2.5, filterable NEI PM25-FIL CAS
Control(s): UNCONTROLLED
Emission Factor -- 3.22E+00 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- U Emissions Factors Applicability

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT PM2.5, primary NEI PM25-PRI CAS
Control(s): UNCONTROLLED
Emission Factor -- 8.92E+00 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- U Emissions Factors Applicability

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT Volatile organic compounds (VOC) NEI VOC CAS
Control(s): UNCONTROLLED
Emission Factor -- 1.20E+00 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- U Emissions Factors Applicability

SCC 30300317
Industrial Processes; Primary Metal Production; Metallurgical Coke Manufacturing; By-product Process: Combustion Stack: Coke Oven Gas (COG)
POLLUTANT PM, filterable NEI PM-FIL CAS
Control(s): UNCONTROLLED
Emission Factor -- 4.70E-01 Lb per Ton Coal Charged; Details
Quality -- A Emissions Factors Applicability

SCC 30300317
Industrial Processes; Primary Metal Production; Metallurgical Coke Manufacturing; By-product Process: Combustion Stack: Coke Oven Gas (COG)
POLLUTANT PM, filterable NEI PM-FIL CAS
Control(s): BAGHOUSE
Emission Factor -- 1.10E-01 Lb per Ton Coal Charged; Details
Quality -- D Emissions Factors Applicability

SCC 30300317
Industrial Processes; Primary Metal Production; Metallurgical Coke Manufacturing; By-product Process: Combustion Stack: Coke Oven Gas (COG)
POLLUTANT PM, filterable NEI PM-FIL CAS
Control(s): ELECTROSTATIC PRECIPITATOR - DRY (DESP)
Emission Factor -- 9.10E-02 Lb per Ton Coal Charged; Details
Quality -- D Emissions Factors Applicability

SCC 30300317
Industrial Processes; Primary Metal Production; Metallurgical Coke Manufacturing; By-product Process: Combustion Stack: Coke Oven Gas (COG)
POLLUTANT PM10, filterable NEI PM10-FIL CAS
Control(s): UNCONTROLLED
Emission Factor -- 4.50E-01 Lb per Ton Coal Charged; Details
Quality -- E Emissions Factors Applicability

SCC 30300317
Industrial Processes; Primary Metal Production; Metallurgical Coke Manufacturing; By-product Process: Combustion Stack: Coke Oven Gas (COG)
POLLUTANT PM2.5, filterable NEI PM25-FIL CAS
Control(s): UNCONTROLLED
Emission Factor -- 4.40E-01 Lb per Ton Coal Charged; Details
Quality -- E Emissions Factors Applicability

SCC 30300317
Industrial Processes; Primary Metal Production; Metallurgical Coke Manufacturing; By-product Process: Combustion Stack: Coke Oven Gas (COG)
POLLUTANT Sulfur dioxide NEI SO2 CAS 7446-09-5
Control(s): UNCONTROLLED
Emission Factor -- 2.80E-01 Lb per Ton Coal Charged; Details
Quality -- C Emissions Factors Applicability

WebFIRE contains more than one record that meets your search criteria. See the Note field on the Details page for more information regarding the applicability of the emissions factor.

SCC 30300317
Industrial Processes; Primary Metal Production; Metallurgical Coke Manufacturing; By-product Process: Combustion Stack: Coke Oven Gas (COG)

POLLUTANT Sulfur dioxide NEI SO2 CAS 7446-09-5

Control(s): UNCONTROLLED
Emission Factor -- 4.00E+00 Lb per Ton Coal Charged; Details
Quality -- D Emissions Factors Applicability

WebFIRE contains more than one record that meets your search criteria. See the Note field on the Details page for more information regarding the applicability of the emissions factor.

SCC 39000789
Industrial Processes; In-process Fuel Use; Process Gas; Coke Oven Gas

POLLUTANT PM10, filterable NEI PM10-FIL CAS

Control(s): UNCONTROLLED
Emission Factor -- 4.30E+00 Lb per Million Standard Cubic Feet Coke Oven Gas Burned; Details
Quality -- U Emissions Factors Applicability

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- Flickr
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Including one revoked factor

Emission Factor Results

18 factors found.

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT Carbon monoxide NEI CO CAS 630-08-0
Control(s): UNCONTROLLED
Emission Factor -- 1.84E+01 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- U Emissions Factors Applicability

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT Nitrogen oxides (NOx) NEI NOX CAS
Control(s): UNCONTROLLED
Emission Factor -- 8.00E+01 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- U Emissions Factors Applicability

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT PM, condensable NEI PM-CON CAS
Control(s): UNCONTROLLED
Emission Factor -- 5.70E+00 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- E Emissions Factors Applicability

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT PM, filterable NEI PM-FIL CAS
Control(s): UNCONTROLLED
Emission Factor -- 6.20E+00 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- U Emissions Factors Applicability

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT PM10, filterable NEI PM10-FIL CAS
Control(s): UNCONTROLLED

Emission Factor -- 4.35E+00 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- U Emissions Factors Applicability

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT PM10, primary NEI PM10-PRI CAS
Control(s): UNCONTROLLED
Emission Factor -- 1.01E+01 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- U Emissions Factors Applicability

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT PM2.5, filterable NEI PM25-FIL CAS
Control(s): UNCONTROLLED
Emission Factor -- 3.22E+00 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- U Emissions Factors Applicability

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT PM2.5, primary NEI PM25-PRI CAS
Control(s): UNCONTROLLED
Emission Factor -- 8.92E+00 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- U Emissions Factors Applicability

SCC 10200707
External Combustion; Industrial: Boilers; Process Gas; Coke Oven Gas
POLLUTANT Volatile organic compounds (VOC) NEI VOC CAS
Control(s): UNCONTROLLED
Emission Factor -- 1.20E+00 Lb per Million Standard Cubic Feet Process Gas Burned; Details
Quality -- U Emissions Factors Applicability

This is the factor that was revoked

Total goes down 18 to 17 factor

SCC 30300317
Industrial Processes; Primary Metal Production; Metallurgical Coke Manufacturing; By-product Process: Combustion Stack: Coke Oven Gas (COG)
POLLUTANT PM, filterable NEI PM-FIL CAS
Control(s): UNCONTROLLED
Emission Factor -- 4.70E-01 Lb per Ton Coke Produced; Details

Quality -- A Emissions Factors Applicability

WebFIRE contains more than one record that meets your search criteria. See the Note field on the Details page for more information regarding the applicability of the emissions factor.

Revoked on 09/15/1998

SCC 30300317
Industrial Processes; Primary Metal Production; Metallurgical Coke Manufacturing; By-product Process: Combustion Stack: Coke Oven Gas (COG)
POLLUTANT PM, filterable NEI PM-FIL CAS
Control(s): UNCONTROLLED
Emission Factor -- 4.70E-01 Lb per Ton Coal Charged; Details
Quality -- A Emissions Factors Applicability

SCC 30300317
Industrial Processes; Primary Metal Production; Metallurgical Coke Manufacturing; By-product Process: Combustion Stack: Coke Oven Gas (COG)
POLLUTANT PM, filterable NEI PM-FIL CAS
Control(s): BAGHOUSE
Emission Factor -- 1.10E-01 Lb per Ton Coal Charged; Details
Quality -- D Emissions Factors Applicability

SCC 30300317
Industrial Processes; Primary Metal Production; Metallurgical Coke Manufacturing; By-product Process: Combustion Stack: Coke Oven Gas (COG)
POLLUTANT PM, filterable NEI PM-FIL CAS
Control(s): ELECTROSTATIC PRECIPITATOR - DRY (DESP)
Emission Factor -- 9.10E-02 Lb per Ton Coal Charged; Details
Quality -- D Emissions Factors Applicability

SCC 30300317
Industrial Processes; Primary Metal Production; Metallurgical Coke Manufacturing; By-product Process: Combustion Stack: Coke Oven Gas (COG)
POLLUTANT PM10, filterable NEI PM10-FIL CAS
Control(s): UNCONTROLLED
Emission Factor -- 4.50E-01 Lb per Ton Coal Charged; Details
Quality -- E Emissions Factors Applicability

SCC 30300317
Industrial Processes; Primary Metal Production; Metallurgical Coke Manufacturing; By-product Process: Combustion Stack: Coke Oven Gas (COG)
POLLUTANT PM2.5, filterable NEI PM25-FIL CAS
Control(s): UNCONTROLLED
Emission Factor -- 4.40E-01 Lb per Ton Coal Charged; Details

Quality -- E Emissions Factors Applicability

SCC 30300317
Industrial Processes; Primary Metal Production; Metallurgical Coke Manufacturing; By-product Process: Combustion Stack: Coke Oven Gas (COG)

POLLUTANT Sulfur dioxide NEI SO2 CAS 7446-09-5

Control(s): UNCONTROLLED
Emission Factor -- 2.80E-01 Lb per Ton Coal Charged; Details
Quality -- C Emissions Factors Applicability

WebFIRE contains more than one record that meets your search criteria. See the Note field on the Details page for more information regarding the applicability of the emissions factor.

SCC 30300317
Industrial Processes; Primary Metal Production; Metallurgical Coke Manufacturing; By-product Process: Combustion Stack: Coke Oven Gas (COG)

POLLUTANT Sulfur dioxide NEI SO2 CAS 7446-09-5

Control(s): UNCONTROLLED
Emission Factor -- 4.00E+00 Lb per Ton Coal Charged; Details
Quality -- D Emissions Factors Applicability

WebFIRE contains more than one record that meets your search criteria. See the Note field on the Details page for more information regarding the applicability of the emissions factor.

SCC 39000789
Industrial Processes; In-process Fuel Use; Process Gas; Coke Oven Gas

POLLUTANT PM10, filterable NEI PM10-FIL CAS

Control(s): UNCONTROLLED
Emission Factor -- 4.30E+00 Lb per Million Standard Cubic Feet Coke Oven Gas Burned; Details
Quality -- U Emissions Factors Applicability

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Layoffs expected after U.S. Steel 'indefinitely' idles primary operations at Granite City facility

Layoffs are expected after U.S. Steel announced it would "indefinitely" idle primary operations at its Granite City facility.

By Stephanie Usery
Published: Nov. 28, 2023 at 2:56 PM CST | Updated: Nov. 28, 2023 at 4:03 PM CST

GRANITE CITY, Ill. (KMOV) – Layoffs are expected after U.S. Steel announced it would "indefinitely" idle primary operations at its Granite City facility.

A spokesperson for the company sent the following to First Alert 4 regarding the announcement Tuesday:

"U. S. Steel has indefinitely idled Granite City's primary operations and will meet customer demand by leveraging the Company's active iron and steelmaking facilities. This action was taken in order to help ensure melt capacity is balanced with our order book. Accordingly, the Company has sent the required notices to employees who potentially may be affected. We thank our employees for their contributions and will keep them informed throughout this process."

Congresswoman Nikki Budzinski (IL-13) released the following statement regarding the layoffs:

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"Two months ago, U.S. Steel handed out pink slips to 400 workers as they blamed the United Auto Workers strike for reduced steel demand. Today, with strong steel prices and operations resumed at the Big Three automakers, U.S. Steel is planning to make these layoffs permanent while putting another 600 jobs on the chopping block. It's clear that these layoffs were never about the market and always about targeting organized workers. U.S. Steel must be held

generations. I will continue to closely monitor U.S. Steel's Strategic Alternative Review Process as we maintain hopes that an American-owned company with strong labor relations can step in to better serve our highly-skilled workers and the Granite City community."

According to Budzinski, the layoffs include hundreds of workers who were temporarily suspended in September when Blast Furnace B was idled. At the time, U.S. Steel said it was idling the last operating blast furnace at the Granite City Works plant because of "risk mitigation" after the announcement of the UAW autoworkers strike.

Illinois State Rep. Amy Elik (R-Alton) released the below statement regarding the layoffs:

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"I am disgusted and saddened to hear U.S. Steel's plans to potentially layoff up to 1,000 employees in Madison County. Granite City employees and their families have provided loyal, skilled labor to the steel industry for decades, and U.S. Steel is pulling the rug out from under them. U.S. Steel should be doing everything it can to keep the Granite City steel mill operating at capacity, and I don't see the company making that effort. I am willing to work with anyone to help keep these jobs in Granite City. My heart goes out to all the workers and families impacted, especially during the Holiday season. I join in the sadness and anger of the city of Granite City and the employees who have dedicated their livelihoods to the steel industry."

Elik encouraged employees impacted by the layoff to contact the Southwestern Illinois workNET Center in Wood River to receive job search assistance and potential training opportunities.

In a statement, State Senator Erica Harriss (56th - Glen Carbon) said her office has been in contact with resources to help those impacted. Her full statement is below:

"The news of the closures and layoffs is devastating for our steelworkers, our families, and our entire community. As a granddaughter of a US Steel worker, I understand that these aren't just jobs lost, but these are livelihoods and lives torn apart. The excuses for the closures will offer little comfort to the people who rely on these good-paying jobs to support their families.

"My staff and I are in contact with state, federal, and local resources to ensure we are in the best position to help constituents navigate the uncertain road ahead.

"Our community helped build this company over generations. US Steel is turning its back on our workers, our community, and our state. I stand with the hard-working people of our district and will do everything I can to support our families in the days and months ahead."

In August, U.S. Steel rejected a billion-dollar buyout from rival Cleveland-Cliffs.

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