

Air Permit Application

Major Modification

Sanimax USA, Inc.

SEH No. NACME 123033

May 7, 2013



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May 7, 2013

RE: Major Modification
Air Permit Application
Sanimax USA, Inc.
SEH No. NACME 123033

Fiscal Services – 6th Floor
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

Dear Air Quality Permit Technical Advisor:

Enclosed please find an electronic copy of the application for a major air permit modification for Sanimax USA Inc, of South St. Paul, Minnesota. The original signed certification form, editable emission calculations spreadsheet, and application fee are also enclosed. The facility operates under Air Emission Permit No. 03700070-006.

If you have any questions regarding this permit application, please contact us as noted below, or Troy Bech, Environmental Health & Safety Supervisor at Sanimax (651.451.6858 Ext. 1520 or troy.bech@sanimax.com).

Sincerely Yours,

Katie Hill Brandt, PE
Environmental Engineer
651.490.2032
khillbrandt@sehinc.com

Todd Potas, PE
Project Manager
651.490.2174
tpotas@sehinc.com

KHB/amc

c: Troy Bech, Sanimax USA Inc
Jon Grad, NAC Mechanical & Electrical Services

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Major Modification
Air Permit Application
Sanimax USA, Inc.

SEH No. NACME 123033

May 7, 2013

Short Elliott Hendrickson Inc.
3535 Vadnais Center Drive
Saint Paul, MN 55110-5196

Distribution List

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Vadnais Heights, MN 55110

Executive Summary

Sanimax USA Inc. (Sanimax) submits this major air permit modification application for the installation of a new 37 million British thermal unit per hour (MMBtu/hr) boiler at the facility. Sanimax is an animal, vegetable and food processing waste recycling plant located at 505 Hardman Avenue South, Dakota County, South St. Paul, Minnesota. The facility operates under Air Emission Permit No. 03700070-006.

In addition to the new boiler, Sanimax also requests to discontinue use of No. 6 fuel oil at the facility, remove the facility-wide SO₂ emission limit, change the compliance requirements associated with firing refined animal fats and vegetable oils (RAFVO) as fuel, expand the operating pressure drop ranges for their Venturi scrubbers, and update emission limits for three emission units.

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Air Permit Application

Major Modification

Prepared for Sanimax USA, Inc.

1.0 Introduction

Sanimax USA Inc. (Sanimax) submits this application for a major air quality permit amendment to Air Emission Permit No. 03700070-006. Sanimax is located in South St. Paul, Minnesota and recycles animal, vegetable, and food processing waste materials. The products manufactured from these recycled materials are primarily used by the animal feed manufacturing and chemical industries. The primary products processed at Sanimax's manufacturing facility are: beef, poultry, and pork by-products; animal and vegetable oils; and a variety of other recycled waste materials from food processing, meat processing, and livestock industries. Sanimax is requesting a permit amendment for the installation of a new 37 MMBtu/hr natural gas fired boiler at their facility. The new boiler will have No. 2 diesel fuel and propane as back-up fuels. Emissions increases from the boiler are below moderate permit amendment thresholds; however, the boiler installation constitutes a major permit amendment due to changes to Title I conditions in the existing air permit. As part of this amendment, the also facility proposes to discontinue use of No. 6 fuel oil, remove the facility-wide SO₂ emission limit, change the compliance requirements associated with firing refined animal fats and vegetable oils (RAFVO) as fuel, expand the operating pressure drop ranges for their Venturi scrubbers, and update emission limits for three emission units (EU001, EU002, and EU006).

2.0 Potential to Emit Summary

The facility-wide potential to emit (PTE) for criteria pollutants particulate matter (PM), PM less than 10 microns in diameter (PM₁₀), PM less than 2.5 microns in diameter (PM_{2.5}), sulfur dioxide (SO₂), oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOC); carbon dioxide equivalents (CO₂e); and hazardous air pollutants (HAPs) is provided in Table 1 below.

**Table 1
Facility PTE**

PTE (tpy)	PM	PM₁₀	PM_{2.5}	SO₂	NOx	CO	VOC	CO₂e	HAPs
Current Facility PTE*	57.6	50.2	31.8	240	96.0	26.5	13.1	55,220	0.60
Change in Emissions	(19.5)	(18.8)	(10.7)	(201.4)	(22.3)	13.4	3.0	27,335	0.30
Proposed Facility PTE	38.1	31.3	21.1	38.6	73.8	39.9	16.1	82,556	0.90
* Potential to emit from the existing facility, as presented in the current Total Facility Operating Permit and January 2013 Permit Renewal Application.									

3.0 Requested Permit Amendments

Sanimax requests that the following changes be made to Air Emission Permit No. 03700070-006. Additional information on each change is provided in the MPCA application forms in Appendix A.

3.1 New Boiler

Table 3 includes specifics regarding the new emission unit to be installed at the facility. The addition of EU023 will also affect GP001 in Table A of the permit.

**Table 2
New Boiler**

Emission Unit / Stack/Vent ID	Description	Firing Capacity, MMBtu/hr (hp)	Fuel Types	Control Equipment
EU023 / SV019	Mobile Boiler	37 (900)	Natural Gas (No. 2 distillate oil and propane for back-up)	None

3.2 No. 6 Fuel Oil and SO₂ Facility-wide Emission Limit

At this time, Sanimax requests to eliminate No. 6 (residual) fuel oil from the list of allowable fuels for EU001 (Boiler No. 1). Discontinuing the use of No. 6 fuel oil will significantly reduce the facility's PTE for PM, PM₁₀, PM_{2.5}, SO₂, and NOx. A decrease in potential SO₂ emissions is also realized when taking into account federal non-road diesel fuel standards, which require that non-road diesel must contain a maximum of 15 ppm sulfur, per 40 CFR Part 80 Subpart I. These changes will decrease potential SO₂ emissions to below major source thresholds such that the facility-wide SO₂ limit is no longer needed. Therefore, Sanimax also requests that the facility-wide SO₂ limit of 240 tpy and associated operating and recordkeeping requirements be removed from the permit. These changes affect GP001, EU001, EU002, and EU006 in Table A of the permit.

3.3 Refined Animal Fats and Vegetable Oils (RAFVO) Fuels

Air Emission Permit No. 03700070-006 currently allows Sanimax to fire a variety of fuels in EU001 (Boiler No. 1), EU002 (Ring/Blood Dryer), and EU006 (Boiler No. 2), including RAFVO. RAFVO is only fired when economically feasible and has not been used as a fuel at Sanimax since December 2008. Currently, potential emissions from RAFVO combustion at

Sanimax use emission factors for No. 4 fuel oil combustion. Based on available test data^{1,2} and the type of RAFVO that Sanimax will likely fire in the future (yellow grease), it is likely that No. 4 fuel oil emission factors overestimate potential emissions at Sanimax. MPCA staff has agreed to allow emission factors for No. 2 fuel oil to estimate emissions from firing RAFVO, but in order to combust RAFVO in the future, Sanimax must complete emission testing to verify that PM_{2.5} emissions from firing RAFVO are not in violation of any permit limits.³ These changes affect GP001 in Table A of the permit.

3.4 Particulate Emission Limits

The PTE for PM, PM₁₀, and PM_{2.5} from EU001 will decrease with the removal of fuel oil No. 6 as a fuel option. New emission limits are proposed based on worst-case emissions for the remaining allowable fuels. These changes will affect EU001 in Table A of the permit.

It was determined that the PM_{2.5} emission limits for both EU002 and EU006 are incorrectly stated in the current permit. Worst-case emissions of PM_{2.5} for these units result when firing natural gas or propane, not fuel oil No. 2. Increased PM_{2.5} emission limits are proposed for both emission units. These changes will affect EU002 and EU006 in Table A of the permit.

Similarly, potential emissions of CO₂e, HAPs, and other criteria pollutants have been updated based on worst-case fuel emissions for EU001, EU002, and EU006, all of which have the option of firing natural gas, fuel oil No. 2, propane, and RAFVO. Previous permitting submittals did not account for all allowable fuels when calculating PTE.

3.5 Scrubber Pressure Drops

Sanimax also requests to expand the operating pressure drop ranges for their Venturi scrubbers (CE001, CE003, and CE012) from a range of 4.0 to 6.0 inches of water column to a range of 3.5 to 7.0 inches of water column. This expanded range will allow the scrubbers to operate with higher water recirculation rates, leading to higher particulate removal. The expanded range will also allow the scrubber differential pressure ranges to account for fluctuations related to seasonal operating temperature and barometric pressure changes. The original ranges of 4.0 to 6.0 have proven to be too tight to account for all operating conditions. These changes will affect CE001, CE003, and CE012 in Table A of the permit.

4.0 Regulatory Applicability

4.1 NSPS for Small Industrial-Commercial-Institutional Steam Generating Units

The New Source Performance Standard (NSPS) for Small Industrial, Commercial, and Institutional Steam Generating Units constructed after June 9, 1989 with heat input capacities between 10 and 100 MMBtu/hr (40 CFR Part 60 Subpart Dc) applies to the new boiler at Sanimax. This emission unit will fire natural gas with propane and No. 2 fuel oil as back-up fuels. Sanimax will comply with the applicable reporting and recordkeeping provisions of NSPS Dc. The boiler will not qualify for the “temporary” boiler exemption under NSPS Dc since it will be in use at Sanimax for over 180 days. A copy of NSPS Dc highlighting portions of the rule applicable to the proposed boiler is included in this submittal.

¹ “Assessment of Emissions Data and State Permit Information Available for Burning Biofuels Fuels (e.g., Animal Fats and Reclaimed Greases and Oils),” U.S EPA memorandum, March 21, 2003.

<http://www.epa.gov/ttn/caaa/t3/reports/aedsp.pdf>

² “A Demonstration of Fat and Grease as an Industrial Boiler Fuel,” Adams, Thomas T., The University of Georgia Engineering Outreach Service, June 30, 2002. http://www.biorefinery.uga.edu/docs/biofuel_oil_report.pdf

³ Phone conversation between Katie Hill Brandt, SEH, and Cassandra Meyer, MPCA, on March 12, 2013.

4.2 NESHAP for Area Sources: Industrial, Commercial, and Institutional Boilers

The National Emission Standards for Hazardous Air Pollutants (NESHAP) for Area Source Industrial, Commercial, and Institutional Boilers (40 CFR Part 63 Subpart JJJJJJ) applies to the new boiler at Sanimax. However, this boiler will qualify for the “temporary” boiler exemption under NESHAP JJJJJJ. This boiler will be fixed to a trailer (not attached to a foundation) and will likely be in operation at the facility for less than 12 months. If circumstances dictate that the boiler must be in operation for more than 12 months, the boiler would then become subject to the rule’s PM (filterable) emission limitations and the requirement to conduct regular tune-ups. A copy of NESHAP JJJJJJ highlighting portions of the rule applicable to the proposed boiler is included in this submittal.

The two other existing boilers at Sanimax will be subject to portions of NESHAP JJJJJJ after the March 21, 2014 compliance date for existing sources.

5.0 Dispersion Modeling

Page A-1 of the Sanimax Air Emission Permit No. 03700070-006 states: “For changes that require a minor, moderate, or major permit amendment and affect any modeled parameter or emission rate documented in Appendix II, a Remodeling Submittal requirement is triggered.” In addition, Section 3.2 of the Air Emission Permit Technical Support Document indicates that changes to PM₁₀ emission rates require parameter documentation in the permit (no remodeling, MPCA Modeling “Tier 1”), and changes to PM_{2.5} emission rates require parameter documentation and submittal/approval for major/moderate/minor amendment levels (MPCA Modeling “Tier 3”). As such, a full remodeling protocol has been submitted and approved for changes to PM_{2.5} emission rates associated with this proposed permit modification.

The modeling results indicate that the facility is in compliance with National Ambient Air Quality Standards (NAAQS) for PM_{2.5}. Results are provided in the following table.

Table 3
Dispersion Modeling Results

NAAQS	Standard, µg/m ³	Modeled	Background*	Total	Available	% Consumed
PM _{2.5} , 24-hour	35	7.97107	27	34.97107	0.02893	99.92%
PM _{2.5} , annual	12	0.81429	9.1	9.91429	2.08571	82.62%
*Annual background concentrations from monitor 871 in St. Paul for the three-year period of 2010-2012.						

The modeling report form is included in Appendix E of this submittal, and all required modeling files and forms will be submitted under separate cover to the MPCA Air Quality Permit Document Coordinator, per form AQDMR-01.

Appendix A

MPCA Application Forms



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

SCP-01: Submittal Cover Page

Permit Application/Notification/
Determination Request Fee Submittal
Air Quality Permit Program

Doc Type: Permit Application

Instructions on Page 7

- 1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578
- 2) Facility Name: Sanimax USA Inc
- 3) Submittal is (choose from the following options and then complete the remainder of item 3 as directed:
- ☐ The final certified (or recertified) version of a previously-submitted permit application. **Complete Section 3A.**
 - ☐ Additional or supplemental information requested by permit staff during the permit-writing process. **Complete Section 3A.**
 - ☐ A request that the Minnesota Pollution Control Agency (MPCA) make an applicability determination. **Complete Section 3A.**
 - ☐ An application for a new individual Part 70 or State permit – choose **one** of the following:
 - ☐ This is the original application or replacement for a denied application – **Complete Section 3B.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is different than the incomplete application – **Complete Section 3B.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is exactly the same as in the incomplete application – **Complete Section 3E.**
 - ☐ An application for reissuance of an individual Part 70 or State permit – choose **one** of the following:
 - ☐ This is the original application or replacement for a denied application – **Complete Section 3B.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is different than the incomplete application – **Complete Section 3B.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is exactly the same as in the incomplete application – **Complete Section 3E.**
 - ☒ An application for an amendment to an existing individual Part 70 or State permit – choose **one** of the following:
 - ☒ This is the original application or replacement for a denied application – **Complete Section 3B.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is different than the incomplete application – **Complete Section 3B.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is exactly the same as in the incomplete application – **Complete Section 3E.**
 - ☐ An application for a Registration Permit, Capped Permit, or General Permit – choose **one** of the following:
 - ☐ This is the original application or replacement for a denied application – **Complete Section 3C.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is different than the incomplete application – **Complete Section 3C.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is exactly the same as in the incomplete application – **Complete Section 3E.**
 - ☐ An application for an administrative change to an existing Registration, Capped, or General Permit – choose **one** of the following:
 - ☐ This is the original application or replacement for a denied application – **Complete Section 3C.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is different than the incomplete application – **Complete Section 3C.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is exactly the same as in the incomplete application – **Complete Section 3E.**
 - ☐ A notification required under Minn. R. 7007.1150(C); Minn. R. 7007.1250, subp. 4; Minn. R. 7007.1350; or Minn. R. 7007.1110, subp. 10, 11, or 11a. **Complete Section 3D.**
 - ☐ A notification from a hot mix asphalt plant holding a Registration Permit of the intent to incorporate ground tear-off shingles and/or manufacturer scrap shingles in the hot mix asphalt. **Complete Section 3D.**

Section 3A - Request for Applicability Determination, Recertification of a Previously-Submitted Permit Application, or Supplement to a Previously-Submitted Permit Application

Use this section only if your submittal is one of the following:

- The final version of a previously submitted permit application, incorporating changes negotiated through the permitting process, or
- Submittal of additional or supplemental information requested by permit staff during the permit-writing process, or
- A request for the MPCA to make an applicability determination.

For final versions and supplemental information, enter the "tracking number" which can be obtained from the MPCA permit staff working on the permit.

Check one of the boxes below. Do not complete Sections 3B, 3C, 3D, or 3E. Continue with item 4 of the form.

Choose one of the following:	Quantity	Points	Total points
☐ Recertification of a previously-submitted permit application – Tracking No: _____	NA	NA	NA
☐ Supplement to a previously-submitted permit application – Tracking No: _____	NA	NA	NA
☐ An Applicability Determination Request		x 10 =	

Section 3B - Application for an Individual Part 70 or State Permit, Reissuance of an Individual Part 70 or State Permit, or Amendment of an Individual Part 70 or State Permit

Is this application replacing an application that was returned as incomplete (not an application that was denied)?

☒ No ☐ Yes Enter the Tracking Number of the incomplete application being replaced: _____

Check as many of the boxes below as apply. If your submittal also includes notifications that do not require a permit application, also complete Section 3D. Then continue with item 4 of the form.

Choose one of the following:	Quantity	Points	Total points
☐ Application for an individual Part 70 permit		x 75 =	
☐ Application for an individual State permit		x 50 =	
☐ Application for reissuance of an expiring individual Part 70 or state permit			
Expiration date: _____ Application due date (180 days prior to expiration): _____ (mm/dd/yyyy) (mm/dd/yyyy)	NA	NA	NA
☒ Application for a Major Amendment to an individual State or Part 70 permit ☐ Includes Reconstruction or Modification of a New Source Performance Standards (NSPS) Affected Facility not subject to New Source Review	1	x 25 =	25
☐ Application for a Moderate Amendment to an individual State or Part 70 permit		x 15 =	
☐ Application for a Minor Amendment to an individual State or Part 70 permit		x 4 =	
☐ Application for an Administrative Amendment to an individual State or Part 70 permit		x 1 =	

Additional Information (check all that apply):

- ☒ Submittal was preceded by pre-application work with the MPCA (for example: dispersion modeling or modeling protocol review, AERA review, environmental review). The tracking number associated with the preapplication work is: _____
- ☒ Permit will replace an existing permit of a different type (e.g., replacing a Capped Permit with an individual State permit, or replacing a Part 70 General permit with an individual Part 70 permit).
- ☐ Permit is for construction of a new facility.
- ☐ Permit is required because of a modification to an existing facility, making the facility subject for the first time for the requirement for an air emission permit.
- ☐ Project is subject to Prevention of Significant Deterioration (PSD) (40 CFR § 52.21)
 - Send a complete copy of the application to U.S. Environmental Protection Agency (EPA) Region V (see instructions).
 - Contact EPA Region V to begin the Endangered Species Assessment process (see instructions).
- ☐ Permit is required because of installation or modification of a Part 61 National Emission Standards for Hazardous Air Pollutants (NESHAP) and/or a Part 60 NSPS Affected Facility at a Stationary Source with Potential-to-Emit below all permit thresholds (Minn. R. 7007.0500, subp. 2.C.(1)).

Section 3C - Application for a Registration, Capped, or General Permit

Is this application replacing an application that was returned as incomplete (not an application that was denied)?

☐ No ☐ Yes Enter the Tracking Number of the incomplete application being replaced: _____.

Check as many of the boxes below as apply. Continue with item 4 of the form.

Choose one of the following:	Quantity	Points	Total Points
☐ Application for a Registration Permit ☐ Option A ☐ Option B ☐ Option C ☐ Option D		x 2 =	
☐ Application for a Capped Permit ☐ Option 1 ☐ Option 2		x 4 =	
☐ Application for a Part 70 General Permit ☐ Manufacturing General Permit ☐ Fiberglass General Permit		x 4 =	
☐ Application for a State General Permit ☐ Nonmetallic Mineral Processing General Permit		x 3 =	
☐ Application for an Administrative Change to an existing Registration, Capped, or General Permit (e.g., change of facility ownership; see instructions for more)		x 1 =	

Additional Information (check all that apply):

- ☐ Permit will replace an existing permit of a different type (e.g., replacing a Registration Permit with a Capped Permit; replacing an Option B Registration Permit with an Option D Registration Permit; etc.)
- ☐ Permit is required for construction of a new facility
- ☐ Permit is required because of a modification to an existing facility, making the facility subject for the first time for the requirement for an air emission permit.
- ☐ Permit is required because of a modification or change making the facility ineligible for its existing air emission permit.

Section 3D - Notifications

If your submittal also includes a permit application, then also complete Section 3A, 3B, 3C, or 3e as applicable. Check all applicable boxes below, then continue with item 4 of the form.

- ☐ A Notification of Accumulated Insignificant Activities (Minn. R. 7007.1250, subp. 4)
- ☐ A Notification of Installation of Pollution Control Equipment (Minn. R. 7007.1150, item C)
- ☐ A Notification of Replacement of a Unit (Minn. R. 7007.1150, item C)
- ☐ A Notification of Replacement of Controls with Listed Controls (Minn. R. 7007.1150, item C)
- ☐ A Notification of Changes That Contravene a Permit Term (Minn. R. 7007.1350)
- ☐ A Notification of Applicability of a New NSPS (applies to Registration Permits) (Minn. R. 7007.1110, subp. 10)
- ☐ A Notification of Changes (not Modifications) Causing a New Permit to be Needed (applies to Registration Permits) (Minn. R. 7007.1110, subp. 11)
- ☐ A Notification of a Regulatory Change Causing a New Permit to be Needed (applies to Registration Permits) (Minn. R. 7007.1110, subp. 11a)
- ☐ A Notification From a Hot Mix Asphalt Plant Including a Request to Incorporate Ground Tear-off Shingles and/or Manufacturer Scrap Shingles in the Hot Mix Asphalt (applies to Registration Permits) Minn. R. 7011.0913, subp. 3)

Section 3E -Replacement for an Incomplete Application Where the Project Scope is Unchanged

Enter the Tracking Number of the incomplete application being replaced: _____.

Check one option under "i" and one option under "ii". Calculate the points difference in "iii". Check all that apply under "iv." Then continue with item 4 of the form.

i. Choose one of the following describing this application:	Quantity	Points	Total Points
☐ Application for an individual Part 70 permit		x 75 =	
☐ Application for an individual State permit		x 50 =	

☐ Application for a Major Amendment to an individual State or Part 70 permit ☐ Includes Reconstruction or Modification of a New Source Performance Standards (NSPS) Affected Facility not subject to New Source Review		x 25 =	
☐ Application for a Moderate Amendment to an individual State or Part 70 permit		x 15 =	
☐ Application for a Minor Amendment to an individual State or Part 70 permit		x 4 =	
☐ Application for a Registration Permit ☐ Option A ☐ Option B ☐ Option C ☐ Option D		x 2 =	
☐ Application for a Capped Permit ☐ Option 1 ☐ Option 2		x 4 =	
☐ Application for a Part 70 General Permit ☐ Manufacturing General Permit ☐ Fiberglass General Permit		x 4 =	
☐ Application for a State General Permit ☐ Nonmetallic Mineral Processing General Permit		x 3 =	
☐ Application for an Administrative Change to an existing Registration, Capped, or General Permit (e.g., change of facility ownership; see instructions for more)		x 1 =	
i. Choose one of the following describing the incomplete application being replaced:	Quantity	Points	Total Points
☐ Application for an individual Part 70 permit		x 75 =	
☐ Application for an individual State permit		x 50 =	
☐ Application for a Major Amendment to an individual State or Part 70 permit		x 25 =	
☐ Application for a Moderate Amendment to an individual State or Part 70 permit		x 15 =	
☐ Application for a Minor Amendment to an individual State or Part 70 permit		x 4 =	
☐ Application for an Administrative Amendment to an individual State or Part 70 permit		x 1 =	
☐ Application for a Registration Permit ☐ Option A ☐ Option B ☐ Option C ☐ Option D		x 2 =	
☐ Application for a Capped Permit ☐ Option 1 ☐ Option 2		x 4 =	
☐ Application for a Part 70 General Permit ☐ Manufacturing General Permit ☐ Fiberglass General Permit		x 4 =	
☐ Application for a State General Permit ☐ Nonmetallic Mineral Processing General Permit		x 3 =	
☐ Application for an Administrative Change to an existing Registration, Capped, or General Permit (e.g., change of facility ownership; see instructions for more)		x 1 =	
ii. (Points from part i: _____) – (Points from part ii: _____) = Total points for Section 3E. → If the number is negative (e.g., the number from “ii” is larger than the number from “i”, enter “0”).			
iii. Additional Information (check all that apply):			
☐ Submittal was preceded by pre-application work with the MPCA (for example: dispersion modeling or modeling protocol review, AERA review, environmental review). The tracking number associated with the preapplication work is: _____			
☐ Permit will replace an existing permit of a different type (e.g., replacing a Capped Permit with an individual State permit, or replacing a Part 70 General permit with an individual Part 70 permit)			
☐ Permit is for construction of a new facility.			
☐ Permit is required because of a modification to an existing facility, making the facility subject for the first time for the requirement for an air emission permit.			
☐ Project is subject to Prevention of Significant Deterioration (PSD) (40 CFR § 52.21) • Send a complete copy of the application to U.S. Environmental Protection Agency (EPA) Region V (see instructions). • Contact EPA Region V to begin the Endangered Species Assessment process (see instructions).			
☐ Permit is required because of installation or modification of a Part 61 National Emission Standards for Hazardous Air Pollutants (NESHAP) and/or a Part 60 NSPS Affected Facility at a Stationary Source with Potential-to-Emit below all permit thresholds (Minn. R. 7007.0500, subp. 2.C.(1)).			

4) Total Points ("total points" from Section 3A, 3B, 3C, or 3E part iii)

25

5) Total Application Fee

25	x \$285 =	\$ 7125
(total points from item 4)		(fee amount)

The application fee amount is \$285 per point, payable to the MPCA. Send your payment ("fee amount") with your submittal. The fee is not refundable, per Minn. R. 7002.0016, subp. 1. There may be additional fees assessed during processing of your request, as required by Minn. R. ch. 7002.

6a) Confidentiality Statement:

- ☒ This application does not contain material claimed to be confidential under Minn. Stat. §§ 13.37 subd. 1(b) and 116.075. Skip item 6b, go to item 7.
- ☐ This application contains material which is claimed to be confidential under Minn. Stat. §§ 13.37 subd. 1(b) and 116.075. Complete Item 6b. Your submittal must include both Confidential and Public versions of your application.

Registration Permit applicants may not claim any portion of their application as confidential. If applying for a Registration permit or an administrative change to a Registration Permit, you must check the first box above ("This application does not contain.....").

- ☐ Confidential Copy of Application attached ☐ Public Copy of Application attached

6b) Confidentiality Certification

To certify data for the confidential use of the MPCA, a responsible official must read the following, certify to its truth by filling in the signature block on the following page, and provide the stated attachments.

- ☐ I certify that the enclosed permit application(s) and all attachments have been reviewed by me and do contain confidential material. I understand that only specific data can be considered confidential and not the entire application or permit. I certify that I have enclosed the following to comply with the proper procedure for confidential material:
- ☐ I have enclosed a statement identifying which data contained in my application I consider confidential, and I have explained why I believe the information qualifies for confidential (or non-public) treatment under Minnesota Statutes.
 - ☐ I have explained why the data for which I am seeking confidential treatment should not be considered "emissions data" which the MPCA is required to make available to the public under federal law.
 - ☐ I have enclosed an application containing all pertinent information to allow for completion and issuance of my permit. This document has been clearly marked "confidential".
 - ☐ I have enclosed a second copy of my application with the confidential data blacked out (not omitted or deleted entirely). It is evident from this copy that information was there, but that it is not for public review. This document has been clearly marked "public copy".

Permittee responsible official:

Mr./Ms. _____
Title: _____
Signature: _____
Date: _____

Co-Permittee responsible official (if applicable)

Mr./Ms. _____
Title: _____
Signature: _____
Date: _____

7) Submittal Certification

I certify under penalty of law that the enclosed documents 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 who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete.

I also certify, in accordance with Minn. R. 7007.0500, subp. 2 (K)(2) and subp. 2 (K)(3), that I have reviewed the procedures implemented by my facility to maintain compliance and that those procedures are, to the best of my knowledge and belief,



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

SCP-01: Submittal Cover Page

Permit Application/Notification/
Determination Request Fee Submittal
Air Quality Permit Program

Doc Type: Permit Application

Instructions on Page 7

1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3) Submittal is (choose from the following options and then complete the remainder of item 3 as directed:

- ☐ The final certified (or recertified) version of a previously-submitted permit application. **Complete Section 3A.**
- ☐ Additional or supplemental information requested by permit staff during the permit-writing process. **Complete Section 3A.**
- ☐ A request that the Minnesota Pollution Control Agency (MPCA) make an applicability determination. **Complete Section 3A.**
- ☐ An application for a new individual Part 70 or State permit – choose **one** of the following:
 - ☐ This is the original application or replacement for a denied application – **Complete Section 3B.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is different than the incomplete application – **Complete Section 3B.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is exactly the same as in the incomplete application – **Complete Section 3E.**
- ☐ An application for reissuance of an individual Part 70 or State permit – choose **one** of the following:
 - ☐ This is the original application or replacement for a denied application – **Complete Section 3B.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is different than the incomplete application – **Complete Section 3B.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is exactly the same as in the incomplete application – **Complete Section 3E.**
- ☒ An application for an amendment to an existing individual Part 70 or State permit – choose **one** of the following:
 - ☒ This is the original application or replacement for a denied application – **Complete Section 3B.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is different than the incomplete application – **Complete Section 3B.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is exactly the same as in the incomplete application – **Complete Section 3E.**
- ☐ An application for a Registration Permit, Capped Permit, or General Permit – choose **one** of the following:
 - ☐ This is the original application or replacement for a denied application – **Complete Section 3C.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is different than the incomplete application – **Complete Section 3C.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is exactly the same as in the incomplete application – **Complete Section 3E.**
- ☐ An application for an administrative change to an existing Registration, Capped, or General Permit – choose **one** of the following:
 - ☐ This is the original application or replacement for a denied application – **Complete Section 3C.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is different than the incomplete application – **Complete Section 3C.**
 - ☐ This is the replacement for an application returned as incomplete (not denied) **and** the scope is exactly the same as in the incomplete application – **Complete Section 3E.**
- ☐ A notification required under Minn. R. 7007.1150(C); Minn. R. 7007.1250, subp. 4; Minn. R. 7007.1350; or Minn. R. 7007.1110, subp. 10, 11, or 11a. **Complete Section 3D.**
- ☐ A notification from a hot mix asphalt plant holding a Registration Permit of the intent to incorporate ground tear-off shingles and/or manufacturer scrap shingles in the hot mix asphalt. **Complete Section 3D.**

Section 3A - Request for Applicability Determination, Recertification of a Previously-Submitted Permit Application, or Supplement to a Previously-Submitted Permit Application

Use this section only if your submittal is one of the following:

- The final version of a previously submitted permit application, incorporating changes negotiated through the permitting process, or
- Submittal of additional or supplemental information requested by permit staff during the permit-writing process, or
- A request for the MPCA to make an applicability determination.

For final versions and supplemental information, enter the "tracking number" which can be obtained from the MPCA permit staff working on the permit.

Check one of the boxes below. Do not complete Sections 3B, 3C, 3D, or 3E. Continue with item 4 of the form.

Choose one of the following:	Quantity	Points	Total points
☐ Recertification of a previously-submitted permit application – Tracking No: _____	NA	NA	NA
☐ Supplement to a previously-submitted permit application – Tracking No: _____	NA	NA	NA
☐ An Applicability Determination Request		x 10 =	

Section 3B - Application for an Individual Part 70 or State Permit, Reissuance of an Individual Part 70 or State Permit, or Amendment of an Individual Part 70 or State Permit

Is this application replacing an application that was returned as incomplete (not an application that was denied)?

☒ No ☐ Yes Enter the Tracking Number of the incomplete application being replaced: _____

Check as many of the boxes below as apply. If your submittal also includes notifications that do not require a permit application, also complete Section 3D. Then continue with item 4 of the form.

Choose one of the following:	Quantity	Points	Total points
☐ Application for an individual Part 70 permit		x 75 =	
☐ Application for an individual State permit		x 50 =	
☐ Application for reissuance of an expiring individual Part 70 or state permit			
Expiration date: _____ Application due date (180 days prior to expiration): _____ (mm/dd/yyyy) (mm/dd/yyyy)	NA	NA	NA
☒ Application for a Major Amendment to an individual State or Part 70 permit ☐ Includes Reconstruction or Modification of a New Source Performance Standards (NSPS) Affected Facility not subject to New Source Review	1	x 25 =	25
☐ Application for a Moderate Amendment to an individual State or Part 70 permit		x 15 =	
☐ Application for a Minor Amendment to an individual State or Part 70 permit		x 4 =	
☐ Application for an Administrative Amendment to an individual State or Part 70 permit		x 1 =	

Additional Information (check all that apply):

- ☒ Submittal was preceded by pre-application work with the MPCA (for example: dispersion modeling or modeling protocol review, AERA review, environmental review). The tracking number associated with the preapplication work is: _____
- ☒ Permit will replace an existing permit of a different type (e.g., replacing a Capped Permit with an individual State permit, or replacing a Part 70 General permit with an individual Part 70 permit).
- ☐ Permit is for construction of a new facility.
- ☐ Permit is required because of a modification to an existing facility, making the facility subject for the first time for the requirement for an air emission permit.
- ☐ Project is subject to Prevention of Significant Deterioration (PSD) (40 CFR § 52.21)
- Send a complete copy of the application to U.S. Environmental Protection Agency (EPA) Region V (see instructions).
 - Contact EPA Region V to begin the Endangered Species Assessment process (see instructions).
- ☐ Permit is required because of installation or modification of a Part 61 National Emission Standards for Hazardous Air Pollutants (NESHAP) and/or a Part 60 NSPS Affected Facility at a Stationary Source with Potential-to-Emit below all permit thresholds (Minn. R. 7007.0500, subp. 2.C.(1)).

Section 3C - Application for a Registration, Capped, or General Permit

Is this application replacing an application that was returned as incomplete (not an application that was denied)?

☐ No ☐ Yes Enter the Tracking Number of the incomplete application being replaced: _____.

Check as many of the boxes below as apply. Continue with item 4 of the form.

Choose one of the following:	Quantity	Points	Total Points
☐ Application for a Registration Permit ☐ Option A ☐ Option B ☐ Option C ☐ Option D		x 2 =	
☐ Application for a Capped Permit ☐ Option 1 ☐ Option 2		x 4 =	
☐ Application for a Part 70 General Permit ☐ Manufacturing General Permit ☐ Fiberglass General Permit		x 4 =	
☐ Application for a State General Permit ☐ Nonmetallic Mineral Processing General Permit		x 3 =	
☐ Application for an Administrative Change to an existing Registration, Capped, or General Permit (e.g., change of facility ownership; see instructions for more)		x 1 =	

Additional Information (check all that apply):

- ☐ Permit will replace an existing permit of a different type (e.g., replacing a Registration Permit with a Capped Permit; replacing an Option B Registration Permit with an Option D Registration Permit; etc.)
- ☐ Permit is required for construction of a new facility
- ☐ Permit is required because of a modification to an existing facility, making the facility subject for the first time for the requirement for an air emission permit.
- ☐ Permit is required because of a modification or change making the facility ineligible for its existing air emission permit.

Section 3D - Notifications

If your submittal also includes a permit application, then also complete Section 3A, 3B, 3C, or 3e as applicable. Check all applicable boxes below, then continue with item 4 of the form.

- ☐ A Notification of Accumulated Insignificant Activities (Minn. R. 7007.1250, subp. 4)
- ☐ A Notification of Installation of Pollution Control Equipment (Minn. R. 7007.1150, item C)
- ☐ A Notification of Replacement of a Unit (Minn. R. 7007.1150, item C)
- ☐ A Notification of Replacement of Controls with Listed Controls (Minn. R. 7007.1150, item C)
- ☐ A Notification of Changes That Contravene a Permit Term (Minn. R. 7007.1350)
- ☐ A Notification of Applicability of a New NSPS (applies to Registration Permits) (Minn. R. 7007.1110, subp. 10)
- ☐ A Notification of Changes (not Modifications) Causing a New Permit to be Needed (applies to Registration Permits) (Minn. R. 7007.1110, subp. 11)
- ☐ A Notification of a Regulatory Change Causing a New Permit to be Needed (applies to Registration Permits) (Minn. R. 7007.1110, subp. 11a)
- ☐ A Notification From a Hot Mix Asphalt Plant Including a Request to Incorporate Ground Tear-off Shingles and/or Manufacturer Scrap Shingles in the Hot Mix Asphalt (applies to Registration Permits) Minn. R. 7011.0913, subp. 3)

Section 3E -Replacement for an Incomplete Application Where the Project Scope is Unchanged

Enter the Tracking Number of the incomplete application being replaced: _____.

Check one option under "i" and one option under "ii". Calculate the points difference in "iii". Check all that apply under "iv." Then continue with item 4 of the form.

i. Choose one of the following describing this application:	Quantity	Points	Total Points
☐ Application for an individual Part 70 permit		x 75 =	
☐ Application for an individual State permit		x 50 =	

☐ Application for a Major Amendment to an individual State or Part 70 permit ☐ Includes Reconstruction or Modification of a New Source Performance Standards (NSPS) Affected Facility not subject to New Source Review		x 25 =	
☐ Application for a Moderate Amendment to an individual State or Part 70 permit		x 15 =	
☐ Application for a Minor Amendment to an individual State or Part 70 permit		x 4 =	
☐ Application for a Registration Permit ☐ Option A ☐ Option B ☐ Option C ☐ Option D		x 2 =	
☐ Application for a Capped Permit ☐ Option 1 ☐ Option 2		x 4 =	
☐ Application for a Part 70 General Permit ☐ Manufacturing General Permit ☐ Fiberglass General Permit		x 4 =	
☐ Application for a State General Permit ☐ Nonmetallic Mineral Processing General Permit		x 3 =	
☐ Application for an Administrative Change to an existing Registration, Capped, or General Permit (e.g., change of facility ownership; see instructions for more)		x 1 =	
i. Choose one of the following describing the incomplete application being replaced:	Quantity	Points	Total Points
☐ Application for an individual Part 70 permit		x 75 =	
☐ Application for an individual State permit		x 50 =	
☐ Application for a Major Amendment to an individual State or Part 70 permit		x 25 =	
☐ Application for a Moderate Amendment to an individual State or Part 70 permit		x 15 =	
☐ Application for a Minor Amendment to an individual State or Part 70 permit		x 4 =	
☐ Application for an Administrative Amendment to an individual State or Part 70 permit		x 1 =	
☐ Application for a Registration Permit ☐ Option A ☐ Option B ☐ Option C ☐ Option D		x 2 =	
☐ Application for a Capped Permit ☐ Option 1 ☐ Option 2		x 4 =	
☐ Application for a Part 70 General Permit ☐ Manufacturing General Permit ☐ Fiberglass General Permit		x 4 =	
☐ Application for a State General Permit ☐ Nonmetallic Mineral Processing General Permit		x 3 =	
☐ Application for an Administrative Change to an existing Registration, Capped, or General Permit (e.g., change of facility ownership; see instructions for more)		x 1 =	
ii. (Points from part i: _____) – (Points from part ii: _____) = Total points for Section 3E. → If the number is negative (e.g., the number from “ii” is larger than the number from “i”, enter “0”).			
iii. Additional Information (check all that apply):			
☐ Submittal was preceded by pre-application work with the MPCA (for example: dispersion modeling or modeling protocol review, AERA review, environmental review). The tracking number associated with the preapplication work is: _____			
☐ Permit will replace an existing permit of a different type (e.g., replacing a Capped Permit with an individual State permit, or replacing a Part 70 General permit with an individual Part 70 permit)			
☐ Permit is for construction of a new facility.			
☐ Permit is required because of a modification to an existing facility, making the facility subject for the first time for the requirement for an air emission permit.			
☐ Project is subject to Prevention of Significant Deterioration (PSD) (40 CFR § 52.21) • Send a complete copy of the application to U.S. Environmental Protection Agency (EPA) Region V (see instructions). • Contact EPA Region V to begin the Endangered Species Assessment process (see instructions).			
☐ Permit is required because of installation or modification of a Part 61 National Emission Standards for Hazardous Air Pollutants (NESHAP) and/or a Part 60 NSPS Affected Facility at a Stationary Source with Potential-to-Emit below all permit thresholds (Minn. R. 7007.0500, subp. 2.C.(1)).			

4) Total Points ("total points" from Section 3A, 3B, 3C, or 3E part iii)

25

5) Total Application Fee

25	x \$285 =	\$ 7125
(total points from item 4)		(fee amount)

The application fee amount is \$285 per point, payable to the MPCA. Send your payment ("fee amount") with your submittal. The fee is not refundable, per Minn. R. 7002.0016, subp. 1. There may be additional fees assessed during processing of your request, as required by Minn. R. ch. 7002.

6a) Confidentiality Statement:

- ☒ This application does not contain material claimed to be confidential under Minn. Stat. §§ 13.37 subd. 1(b) and 116.075. Skip item 6b, go to item 7.
- ☐ This application contains material which is claimed to be confidential under Minn. Stat. §§ 13.37 subd. 1(b) and 116.075. Complete Item 6b. Your submittal must include both Confidential and Public versions of your application.

Registration Permit applicants may not claim any portion of their application as confidential. If applying for a Registration permit or an administrative change to a Registration Permit, you must check the first box above ("This application does not contain.....").

- ☐ Confidential Copy of Application attached ☐ Public Copy of Application attached

6b) Confidentiality Certification

To certify data for the confidential use of the MPCA, a responsible official must read the following, certify to its truth by filling in the signature block on the following page, and provide the stated attachments.

- ☐ I certify that the enclosed permit application(s) and all attachments have been reviewed by me and do contain confidential material. I understand that only specific data can be considered confidential and not the entire application or permit. I certify that I have enclosed the following to comply with the proper procedure for confidential material:
- ☐ I have enclosed a statement identifying which data contained in my application I consider confidential, and I have explained why I believe the information qualifies for confidential (or non-public) treatment under Minnesota Statutes.
 - ☐ I have explained why the data for which I am seeking confidential treatment should not be considered "emissions data" which the MPCA is required to make available to the public under federal law.
 - ☐ I have enclosed an application containing all pertinent information to allow for completion and issuance of my permit. This document has been clearly marked "confidential".
 - ☐ I have enclosed a second copy of my application with the confidential data blacked out (not omitted or deleted entirely). It is evident from this copy that information was there, but that it is not for public review. This document has been clearly marked "public copy".

Permittee responsible official:

Mr./Ms. _____
Title: _____
Signature: _____
Date: _____

Co-Permittee responsible official (if applicable)

Mr./Ms. _____
Title: _____
Signature: _____
Date: _____

7) Submittal Certification

I certify under penalty of law that the enclosed documents 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 who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete.

I also certify, in accordance with Minn. R. 7007.0500, subp. 2 (K)(2) and subp. 2 (K)(3), that I have reviewed the procedures implemented by my facility to maintain compliance and that those procedures are, to the best of my knowledge and belief,

reasonable to maintain compliance with all applicable requirements, including those that will become applicable during the term of the permit.

Choose one of the following:

- ☐ I certify that no construction is associated with the permit action sought by this permit application.
- ☒ I certify that my project includes construction, but construction has not yet been started except as allowed under Minn. R. 7007.1110, subp. 10 or Minn. R. 7007.1250, subp. 4, and will not begin until the permit is issued except as allowed under Minn. R. 7007.1110, subp. 12; Minn. R. 7007.1142, subp. 2; Minn. R. 7007.1150, item C; or Minn. R. 7007.1450, subp. 7.
- ☐ My project includes construction, and construction other than what is allowed under Minnesota Rules has been started

Permittee responsible official:

Mr./Ms. Donn Johnson

Title: VP of Operations

Signature: _____

Date: _____

Co-Permittee responsible official (if applicable)

Mr./Ms. _____

Title: _____

Signature: _____

Date: _____

8) Package Submittal

Applications, notifications, and/or requests that are submitted without authorized signature(s) (under Submittal Certification for all applications and under Confidentiality Certification if you are seeking confidential treatment of any information in the application); without required forms, and/or without the required application fee, will be returned. Please make your check out to the Minnesota Pollution Control Agency. Send the complete application package and check to:

**Fiscal Services – 6th Floor
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194**

You may choose to submit your application as a “pdf” file on a compact disc (CD). If you choose this option, you must still include a paper copy of any form that requires a signature.

Choose one of the following:

- ☐ I certify that no construction is associated with the permit action sought by this permit application.
- ☒ I certify that my project includes construction, but construction has not yet been started except as allowed under Minn. R. 7007.1110, subp. 10 or Minn. R. 7007.1250, subp. 4, and will not begin until the permit is issued except as allowed under Minn. R. 7007.1110, subp. 12; Minn. R. 7007.1142, subp. 2; Minn. R. 7007.1150, item C; or Minn. R. 7007.1450, subp. 7.
- ☐ My project includes construction, and construction other than what is allowed under Minnesota Rules has been started

Permittee responsible official:

Mr./Ms. Donn Johnson
Title: VP of Operations
Signature: 
Date: 3 May 2013

Co-Permittee responsible official (If applicable)

Mr./Ms. _____
Title: _____
Signature: _____
Date: _____

8) Package Submittal

Applications, notifications, and/or requests that are submitted without authorized signature(s) (under Submittal Certification for all applications and under Confidentiality Certification if you are seeking confidential treatment of any information in the application); without required forms, and/or without the required application fee, will be returned. Please make your check out to the Minnesota Pollution Control Agency. Send the complete application package and check to:

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**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

CH-GI-01

Facility Information for Permit Changes

Air Quality Permit Program

Doc Type: Permit Application

Instructions on Page 3

1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc.

3) Facility Location

Street Address: 505 Hardman Avenue South

City: South St. Paul County: Dakota Zip code: 55705

Note: If the facility is or will be located within the city limits of Minneapolis, attach a map showing the exact location.

Mailing Address:

City: State: Zip code:

4) Corporate/Company Owner

Name: Sanimax USA Inc.

Mailing Address: PO Box 10067

City: Green Bay State: WI Zip code: 54307

Owner Classification: ☒ Private ☐ Local Govt. ☐ State Govt. ☐ Federal Govt. ☐ Utility

5) Corporate/Company Operator (if different than owner)

Name:

Mailing Address:

City: State: Zip code:

6) Co-permittee (if applicable)

Name:

Mailing Address:

City: State: Zip code:

7) Legally responsible official for this permit/facility

Mr/Ms: Mr. Donn Johnson Phone: 920-494-5233 Ext. 1218

Title: VP of Operations Fax:

At (check one): ☒ Owner Address ☐ Operator Address ☐ Emission Facility Address

☐ Other (specify):

8) Contact person for this permit

Mr/Ms: Mr. Troy Bech Phone: 651.451.6858 Ext. 1520

Title: EH&S Supervisor Fax: 651.451.6542

At (check one): ☐ Owner Address ☒ Operator Address ☐ Emission Facility Address

☐ Other (specify):

E-mail address: troy.bech@sanimax.com

9) All billings for annual fees should be addressed to:

Mr/Ms: Troy Bech Phone: 651.451.6858 Ext. 1520

Title: EH&S Supervisor Fax: 651.451.6542

At (check one): ☐ Owner Address ☒ Operator Address ☐ Emission Facility Address

☐ Other (specify) _____

10) Standard Industrial Classification (SIC) Code and description for the facility:

Primary: 2077 / Recycling animal, vegetable, and food processing waste materials

Secondary (if applicable): _____ / _____

Tertiary (if applicable): _____ / _____

11) Primary product produced (or activity performed) at the facility is:

Recycling animal, vegetable, and food processing waste materials primarily used by the animal feed manufacturing and chemical industries

12) Facility is: ☒ Stationary ☐ Portable

13) (reserved for future use)

14) Is environmental review required (either an Environmental Assessment Worksheet (EAW) or an Environmental Impact Statement (EIS)) for this facility?

☒ No ☐ Yes -- you may also be required to perform a state air toxics review for your facility. Please call 1-800-657-3864 or locally 651-296-6300.

15) Are you (or will you be, if this is a new facility) required to submit a Toxics Release Inventory (Form R) under SARA Title 313 for this facility? Contact the Minnesota Emergency Planning and Community Right-to-Know Act (EPCRA) Program for more information, at 651-201-7400.

☒ Yes – Answer Question 15a ☐ No – Go on to Question 16

15a) Are you required to submit a Pollution Prevention Plan Progress Report in accordance with Minn. Stat. § 115D.08?

☐ No ☒ Yes, and the most recently required progress report has been submitted
☐ Yes, but a progress report has not been submitted because: (fill in reason below)

16) Is this facility within 50 miles of another state or the Canadian border?:

☒ Yes (specify which ones) WI ☐ No

17) Are you proposing any alternative operating or emissions trading scenarios in this application? (see Minn. R. 7007.0800, subp. 10 and 11)

☐ No ☐ Yes - attach a description of your proposal, including a statement on how the proposal will meet all applicable requirements (specifically, please address any applicable New Source Review requirements - see Form CH-04).

18) Person preparing this permit application:

Mr. / Ms. Ms. Katie Hill Brandt

Title: Environmental Engineer

Phone: 651.490.2032 Fax: _____ Date: April 5, 2013

E-mail address khillbrandt@sehinc.com



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

CH-15

**SIP Changes and Permits
Air Quality Permit Program**

Doc Type: Permit Application

1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578
2) Facility Name: Sanimax USA Inc.

Section I

I.1 Does your facility have source specific State Implementation Plan (SIP) conditions contained in a Part 70 permit or a federally enforceable state operating permit **or** has your facility been issued an Administrative Order (Order) to ensure compliance with a national ambient air quality standard (NAAQS)? (This would include permit conditions labeled "Title I condition: SIP for [pollutant] NAAQS"). If your facility is listed in Table 1 below, you have source specific SIP conditions.

☐ Yes. Check all applicable pollutants and continue with Section II.

- ☐ Sulfur Dioxide (SO₂)
- ☐ Particulate matter less than 10 microns (PM₁₀)
- ☐ Lead

☒ No. **Stop here**, and submit this form with your application for a permit amendment or operating permit reissuance.

Section II

II.1 Where are the SIP conditions that apply to your facility?

- ☐ In the current operating permit
- ☐ In the Order
- ☐ In both the current operating permit and the Order

II.2 This permit application is for

- ☐ Reissuance of the operating permit
- ☐ An amendment to the current operating permit

Whether you are proposing changes through an application for a facility modification, or if you are submitting a reissuance application and there have been changes at your facility that are not included in the current operating permit or the Order, complete the rest of this form considering those changes as the 'proposed change.' If your facility is subject to the Order, Minnesota Pollution Control Agency (MPCA) will initiate a SIP revision to transfer the Title I conditions from the Order to the Permit.

II.3 Does the proposed change involve equipment or operating parameters that are subject to a Title I SIP condition in your permit or a requirement from your Order?

- ☐ Yes
- ☐ No

II.4 Does the proposed change add an emission unit(s) or stack/vent that will emit the criteria pollutant(s) identified in Section I?

- ☐ Yes
- ☐ No

II.5 Does the proposed change increase the emission rate of the criteria pollutant(s) at any of the existing emission points (emission unit, control equipment or stack/vent)?

- ☐ Yes
- ☐ No

II.6 Does the proposed change increase the overall emission rate of that criteria pollutant at the facility?

- ☐ Yes
- ☐ No

Section III

Review the SIP modeling parameters for your facility. These are usually found in an appendix to your permit or in your Order. For the proposed change at your facility, check all that apply:

- ☐ Addition of new emission point(s) for the criteria pollutant
- ☐ Removal of existing emission point(s) for the criteria pollutant
- ☐ Change in one or more modeled stack/vent heights or diameter
 - ☐ Increase in stack height
 - ☐ Decrease in stack height
 - ☐ Increase in stack diameter
 - ☐ Decrease in stack diameter
- ☐ Change in modeled air flow rate(s)
 - ☐ Increase in air flow rate(s)
 - ☐ Decrease in air flow rate(s)
- ☐ Change in one or more modeled emission rates
 - ☐ Increase in emission rate(s)
 - ☐ Decrease in emission rate(s)
- ☐ Change in location of one or more emission points
- ☐ Change in exit point temperature
 - ☐ Increase in temperature
 - ☐ Decrease in temperature
- ☐ Change in building locations or dimensions
- ☐ Other _____
- ☐ No change to current modeling parameters.

If there are any changes to the modeling parameters, you will need to demonstrate that the plume dispersion characteristics of the criteria pollutant will be equivalent to or better than the dispersion characteristics modeled using the parameters included as noted in the appendix of your permit or in your Order. In many cases you will need to remodel to show attainment with the NAAQS. However, in some cases you may be able to provide a written justification for improved dispersion characteristics.

If you will need to do modeling, it is recommended that you check the MPCA website or contact MPCA staff for guidance on current SIP modeling. SIP modeling requirements may be different than modeling for other programs and may have changed since previous modeling was done for your facility. See the MPCA's on-line SIP and modeling information at <http://www.pca.state.mn.us/veiz4a6> and <http://www.pca.state.mn.us/nwqh421> for current contact information.

Section IV

Will the proposed change require a SIP revision?

In general, a SIP revision is not required if you are making a change to the facility that does not increase, from any emission point, the emission rate of the criteria pollutant or alter equipment or parameters used as the basis for modeling of the criteria pollutant.

If you answered "Yes" to any of the questions in Section II or have identified changes to the modeling parameters for your facility in Section III, you will likely need a SIP revision for your project. If a SIP revision is required for a modification amendment, you must submit a **major** amendment application. If the proposed change includes an increase in emissions of the criteria pollutant or if it is new construction, the current Title I SIP conditions in your permit or the conditions in your Order for your facility must be followed until the SIP revision is approved by U.S. Environmental Protection Agency (EPA). If the proposed change will reduce emissions or will provide better modeled dispersion characteristics that change may proceed with MPCA and EPA approval.

When a SIP revision is part of your permit reissuance or amendment, approval of the reissuance or modification application will include more steps and take more time than the general process for a permit issuance. The SIP revision includes review and approval of the permit application by MPCA, including public notice of the permit. The SIP revision requires a public notice (which may occur concurrently with the permit notice of the draft/proposed permit); EPA generally does a preliminary review of the SIP revision at this time. There is an opportunity for interested parties to request a public meeting during the public notice period. After MPCA's public notice period ends for the draft/proposed permit, MPCA submits the SIP revision to EPA for a formal review and approval. Final approval of the SIP revision occurs when EPA publishes the revision as a final rule in the federal register.

Table 1 Facilities with Source Specific SIP Conditions

Area	Pollutant	Facility
Eagan	Lead	Gopher Resources Corporation
Rochester	PM ₁₀	Rochester Public Utilities ▪ Silver Lake
	SO ₂	Rochester Public Utilities ▪ Cascade Creek ▪ Silver Lake Associated Milk Producers - Rochester Mayo – Franklin Heating Station IBM - Rochester Olmsted Waste to Energy Mayo – St. Mary's Hospital
Twin Cities 7-County Area	SO ₂	Federal Cartridge Company-Anoka Hoffman Enclosures Inc. Xcel Energy ▪ Inver Hills Generating Plant ▪ Riverside Generating Plant GAF Materials Corporation NRG - Minneapolis Energy Center Minneapolis LLC
Rosemount/Pine Bend	SO ₂	Flint Hills Resources Pine Bend Refinery
St. Paul Park/Ashland	SO ₂	St. Paul Park Refining Co. LLC
St. Paul (Childs Road and Red Rock Road)	PM ₁₀	Aggregate Industries, Yard A Cenex Harvest States Coop- Elevator 2 Commercial Asphalt, Inc. Plant 905 Gerdau Ameristeel US Inc. – St. Paul Mill Great Western Dock and Terminal Lafarge North America (Red Rock and Childs Road Terminals) Met Council Wastewater Treatment Plant St. Paul Terminals



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

CH-00

**Project Screening
Air Quality Permit Program**

Doc Type: Permit Application

AQ Facility ID No.: 03700070 AQ File No: 578

Facility Name: Sanimax USA Inc

Instructions: Fill out this form last, after you've determined the type of permit you need.

Check **all** applicable boxes on this form that describe your proposed project and your facility.

Applicable Analyses:

- ☐ My project requires an Environmental Assessment Worksheet.
Submitted to (who?): _____ on (date mm/dd/yyyy): _____
- ☐ My project requires an Environmental Impact Statement.
Submitted to (who?): _____ on (date mm/dd/yyyy): _____
- ☐ My project requires a Prevention of Significant Deterioration (PSD) permit, utilizes the Plant-wide Applicability Limit requirements of 40 CFR § 52.21, and/or involves a Best Available Control Technology (BACT) Analysis (either a new analysis or revisions to previous permit conditions).
- ☐ My project involves a case-by-case Maximum Achievable Control Technology (MACT) determination under section 112(g)(2)(B) of the Clean Air Act Amendments of 1990 as described on form CH-07.
- ☐ My project involves a site-specific alternative monitoring request under 40 CFR § 60.13(i) or 40 CFR § 63.8(f).
- ☐ My project involves changes to limits or requirements that are identified as State Implementation Plan (SIP) requirements in my permit or Administrative Order. (Use Form CH-15 to determine this.)
- ☒ My project involves ambient air dispersion modeling for criteria pollutants.
Modeling protocol was approved on (date mm/dd/yyyy): 4/11/2013
Modeling results submitted to (who?): Melissa Sheffer on (date mm/dd/yyyy): 4/25/2013
☒ Modeling follows protocol exactly ☐ Modeling mostly follows protocol but with minor changes
- ☐ My project involves an Air Emissions Risk Analysis (AERA).
Submitted to (who?): _____ on (date mm/dd/yyyy): _____
- ☐ My project requires at least one other media permit in addition to an air permit (list permits: e.g., National Pollutant Discharge Elimination System [NPDES] permit).

Application submitted to (who?): _____ on (date mm/dd/yyyy): _____
- ☐ None of the above

Industry Sector:

- ☐ Petroleum refining
- ☐ Pulp and/or paper mill
- ☐ Composite wood products (e.g., OSB)
- ☐ Metallic mining
- ☐ Non-beverage ethanol production
- ☐ Waste combustor
- ☐ Electric utility
- ☒ None of the above



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

CH-01

**Change Description
Air Quality Permit Program**

Doc Type: Permit Application

Instructions on Page 2

Instructions: Provide below a description of each physical and operational change, or proposed change to existing permit conditions, included in this application. This includes addition of new units, removal or replacement of existing units, or changes which may result in debottlenecking of emission units. Use Form CH-02 to determine if a permit amendment is required for your proposed change or modification.

1a) AQ Facility ID No.: 03700070 **1b)** AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3) Does your project involve construction or a physical or operational change to your facility?

- ☐ No. Go to question 5
☒ Construction or physical change.
☐ Operational change..

4) Does your project involve the addition or modification of a non-emergency generator?

- ☒ No.
☐ Yes. You must conduct screening modeling for the generator or group of generators. See instructions.

5) Do you need your permit issued by a certain date?

- ☐ No.
☒ Yes. Date: _____
Reason: _____

6) Complete and attach Form CD-01 to specify which applicable requirements need to be added to or deleted from your permit.

7) Description of proposed project, including all physical and/or operational changes:

Sanimax USA Inc. (Sanimax) submits this major air permit modification application for the installation of a new 37 million British thermal unit per hour (MMBtu/hr) boiler at the facility. In addition to the new boiler, Sanimax also requests to discontinue use of No. 6 fuel oil at the facility, remove the facility-wide SO₂ emission limit, change the compliance requirements associated with firing refined animal fats and vegetable oils (RAFVO) as fuel, expand the operating pressure drop ranges for their Venturi scrubbers, and update emission limits for three emission units.



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

CH-02

**Action Type Determination
Air Quality Permit Program**

Doc Type: Permit Application

1a) AQ Facility ID No.: 03700070

1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

Answer the questions on this form, referring to and completing the additional forms as directed, to determine if a permit or amendment is required (and if so what type), or if a notification is required.

- 3.** Does the change consist only of a change in facility ownership or operational control, facility ownership name, or facility name?
- ☒ No. Go to question 4.
- ☐ Yes. Complete Form CH-17 for an administrative change requiring an administrative amendment; proceed to question 12 of this form.
- 4.** Does the change consist only of the extension of a deadline by no more than 120 days? The deadline must be one which Minnesota Pollution Control Agency (MPCA) has authority to extend, and must not have already been extended during the term of the current permit, or the answer to this question must be "no."
- ☒ No. Go to question 5.
- ☐ Yes. Make a copy of the permit page showing the deadline, and mark it up to show the desired extension; include it and Form CH-08 in your submittal. Proceed to question 12 of this form.
- 5.** Does the proposed change or modification require a major amendment? To answer this question, use Form CH-03 and all forms referenced therein. Include these forms in your submittal, unless otherwise noted on Form CH-12 or CH-09, if applicable.
- ☒ Yes. Go to question 10.
- ☐ No. Go to question 6.
- 6.** Does the entire proposed change or modification consist **only** of insignificant activities described in Minn. R. 7007.1300, subparts 2 and/or 3, or conditionally insignificant activities listed in Minn. R. 7008.4100 and/or Minn. R. 7008.4110?
- ☐ Yes. The proposed change qualifies as an insignificant modification under Minn. R. 7007.1250, subp. 1.A. No permit amendment is needed to make the change, and you are done with this form. If the modification triggers new monitoring, record keeping, or reporting requirements under applicable requirements or Minn. R. 7007.0100 to 7007.1850, then you must initiate an administrative amendment under Minn. R. 7007.1400 to include the new requirements no more than 30 days after making the modification. If the proposed change also meets the conditions of Minn. R. 7007.1250, subp. 4, then you must notify the MPCA using Form CH-12.
- ☐ No. Part of the project is not one of the listed insignificant activities listed in Minn. R. 7007.1300, subp. 2 and/or 3, Minn. R. 7008.4100, or Minn. R. 7008.4110. Go to question 7.
- 7.** Can the change be done through an administrative amendment? Use Form CH-08 to determine Yes or No.
- ☐ Yes. Include Form CH-08 in your application. Proceed to question 12.
- ☐ No. Go to question 8.
- 8.** Can the change be made through the "contravening permit terms" provision? Use Form CH-09 to determine Yes or No.
- ☐ Yes. Include Form CH-09 in your submittal. Proceed to question 12.
- ☐ No. Go to question 9.
- 9.** Is a minor or moderate amendment needed? Complete Form CH-10 to determine Yes or No.
- ☐ Yes. Include Form CH-10 in your submittal. Go to question 10.
- ☐ No. Complete Form CH-12 to determine what notification or recordkeeping requirements apply. Proceed to question 12.

- 10.** Complete Form CH-11 to determine your status with regard to crossing permit thresholds, and indicate that status below.
- ☐ This change can be made through the permit amendment provisions of Minn. R. 7007.1450 or 7007.1500. Include Form CH-11 in your submittal. If you are applying for an administrative amendment, proceed to question 12. Otherwise, go to question 11.
- ☒ This change requires issuance of a Title V or State operating permit. Submit a completed Total Facility Application. You are done with this form.
- 11.** Complete Form CH-13 to determine what state rules apply to the equipment you are adding or the changes you are proposing, and include Form CH-13 in your submittal. Then proceed to question 12.
- 12.** In addition to this form and any forms you were instructed herein to include in your submittal, complete and submit Form CH-14 and, any other forms or information as directed on Form CH-14.



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

CH-14

Permit Notification and Amendment Application Requirements Air Quality Permit Program

Doc Type: Permit Application

Instructions on Page 3

1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

- 3) Minn. R. 7007.0600 describes what a permit application must include. The items in the following list constitute an administratively complete application, but do not necessarily mean that the application is technically complete for the purpose of taking final permit action. Please complete the following to verify that you have included all the indicated forms and information.

Included	Not included	Form/Requirement	When required
☒	☒	SCP-01 Submittal Cover Page with original signature	Always
☒	☒	CH-GI-01 Facility Information	Always, except when using Form CH-17 for an administrative change requiring an administrative amendment
☒	☒	CH-15 SIP Changes and Permits	Always, except when using Form CH-17 for an administrative change requiring an administrative amendment
☒	☒	CH-00 Project Screening	Always, except when using Form CH-17 for an administrative change requiring an administrative amendment
☒	☒	CH-01 Change Description	Always
☒	☒	CH-02 Action Type Determination	Always
☒	☒	CH-14 Permit Notification and Amendment Application Requirements	Always
☒	☐	CH-03 Major Permit Amendment Determination	When indicated on CH-02, CH-12, or CH-09
☒	☐	CH-04 Determination of New Source Review Status	When CH-03 is required
☐	☒	CH-04a Determination of Increases at Major Sources	As directed on Form CH-04
☒	☐	CH-04b Determination of Increases at Minor Sources	As directed on Form CH-04
☒	☐	CH-04c Determination of Greenhouse Gas Status Under New Source Review	When CH-03 is required
☐	☒	CH-04d Calculating the Net Emissions Increase Under New Source Review	As directed on Form CH-04a
☐	☒	CH-04e Required Elements for Prevention of Significant Deterioration (PSD) Permit Application	As directed on Form CH-04b or CH-04d
☐	☒	BACT analysis	When the proposed change or modification is major under NSR
☒	☐	CH-05 Applicability of New Source Performance Standards (NSPS)	When CH-03 is required
☒	☐	Highlighted copy of applicable subpart(s) of 40 CFR Part 60, including Subpart A	When so indicated on CH-05

Included	Not included	Form/Requirement	When required
☒	☐	CH-06 Applicability of Part 61 NESHAP	When CH-03 is required
☐	☒	Highlighted copy of applicable subpart(s) of 40 CFR Part 61, including Subpart A	When so indicated on CH-06
☒	☐	CH-07 Applicability of Part 63 NESHAP	When CH-03 is required
☐	☒	Highlighted copy of applicable subpart(s) of 40 CFR Part 63, including Subpart A	When so indicated on CH-07 or CH-08
☒	☐	CH-11 Crossing Permit Thresholds	When indicated on CH-02
☒	☐	CH-13 Applicability of State Rules	When indicated on CH-02
☒	☐	CD-01 Compliance Plan	For all applications for a major, moderate, or minor amendment
☒	☐	GI-07 Facility Emissions Summary	For all amendment applications, except when there are no emission changes
☒	☐	Editable electronic spreadsheet containing all calculations	Whenever GI-07 is required. If submitting the application electronically ("pdf" on a CD), you must include the editable spreadsheet on the CD. If submitting the application on paper, you may submit a CD with the application, or be prepared to email to MPCA staff upon request – indicate choice on GI-07.
☒	☐	Emission calculation printouts (if submitting application electronically as a "pdf" document then the emission calculations must be a part of the the pdf document; if submitting a paper copy of the application, then the emission calculations must be printed on paper as part of the application.)	Whenever GI-07 is required.
☒	☐	HG-01 Mercury Releases to Ambient Air	When building a new or expanded facility where the new or expanded facility emits mercury (or when changing or modifying operation at an existing facility where the changed or modified units emit Hg) from taconite production, secondary metal production, fuel combustion for electricity generation or industrial boilers, or incinerators
☐	☒	GI-09H Requirements: CAM	When adding or changing control equipment or controlled emission units at a Part 70 source
☐	☒	CAM Plan	When indicated on GI-09H
☐	☒	EMS-00 EMS Permit Qualification	When proposing to incorporate Environmental Management System (EMS) provisions
☐	☒	CH-10 Applicability of Minor or Moderate Amendment Process	When applying for a moderate or minor amendment
☐	☒	CH-08 Administrative Amendment Determination	When applying for an administrative amendment other than for a change in facility name, ownership, or ownership name
☐	☒	CH-17 Individual Permit Administrative Changes	When applying only for a change in facility name, ownership, or ownership name
☐	☒	CH-09 Contravening Permit Terms	When proposing contravening permit terms
☐	☒	CH-12 Written Notification Form	When proposing changes that do not require a permit amendment, other than those covered by contravening permit terms
☐	☒	IA-01 Insignificant Activities List	When the proposed change or modification includes changes to insignificant activities

Included	Not included	Form/Requirement	When required
☒	☐	GI-02 Process Flow Diagram	When the proposed change or modification includes changes to the process flow, including removing or adding new emission units, control devices, stacks/vents, tanks, or fugitive sources
☐	☒	Separate sheet showing revised process flow	When the process flow diagram is not drawn directly on Form GI-02
☒	☐	GI-03 Facility and Stack/Vent Diagram	When proposed change or modification includes changes to the stack/vent diagram, including removing or relocating existing stack/vents, or adding new stack/vents
☒	☐	Separate sheet showing revised stack/vent diagram	When the stack/vent diagram is not drawn directly on Form GI-03
☒	☐	GI-04 Stack/Vent Information	When adding or changing stack/vents
☒	☐	GI-05A Pollution Control Equipment Information	When adding or changing control equipment
☒	☐	CD-05 Compliance Plan for Control Equipment	When adding or changing control equipment
☐	☒	HE-01 Hood Evaluation	When adding or changing control equipment that does not collect through a total enclosure
☐	☒	CR-02 Hood Certification	When adding or changing control equipment that does not collect through a total enclosure
☒	☐	GI-05B Emission Unit Information	When adding, replacing, or changing emission units, or adding or replacing a control device controlling an emission unit
☐	☒	GI-05C Tank Information	When adding, replacing, or changing storage tanks, or adding or replacing a control device controlling a tank
☐	☒	GI-05D Fugitive Emission Source Information	When adding, replacing, or changing fugitive sources, or adding or replacing a control device controlling a fugitive source
☐	☒	ME-01 Continuous Monitoring System Information	To describe new, removed, or changed continuous monitoring systems
☐	☒	PAL-01 PAL Cover Page	When requesting a new Plantwide Applicability Limit (PAL) under NSR
☐	☒	PAL-02 Determination of Plantwide Applicability Limit for Major NSR Sources	When requesting a new Plantwide Applicability Limit (PAL) under NSR
☐	☒	MI-02c Modeling for Plantwide Applicability Limitations	When requesting a new Plantwide Applicability Limit (PAL) under NSR
☐	☒	Environmental Assessment Worksheet submitted	Varies – see http://www.pca.state.mn.us/oxpg691
☐	☒	Air Emission Risk Analysis submitted (AERA) submitted	If there is an increase of any criteria pollutant greater than 250 tons per year, or if it is a proposed electric production facility greater than or equal to 25 MW, or if it is an ethanol facility increasing production by 5 million gallons per year, then an AERA will likely be needed – see http://www.pca.state.mn.us/tchy42b
☒	☐	Dispersion modeling submitted	If AERA is needed, or if project is subject to PSD unless only pollutant involved is a Volatile Organic Compound. See http://www.pca.state.mn.us/nwqh421

Instructions for Form CH-14

1a) AQ Facility ID No. -- Fill in your Air Quality (AQ) Facility identification (ID) Number (No.). This is the first eight digits of the permit number for all permits issued under Minn. R. ch. 7007.

1b) AQ File No. -- Fill in your AQ File Number. This number can be found in the “cc” section of correspondence from the Minnesota Pollution Control Agency (MPCA).



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

CH-03

**Major Permit Amendment Determination
Air Quality Permit Program**

Doc Type: Permit Application

Instructions on Page 3

1a) AQ Facility ID No.: 03700070

1b) AQ File No. 578

2) Facility Name: Sanimax USA Inc

To answer the questions posed in this form, you will have to complete the additional forms referenced in the individual items.

This form refers to proposed **changes** and **modifications**. A “modification” as defined in Minn. R. 7007.0100, subp. 14, includes:

- A. any change that constitutes a title I modification ...; or
- B. any physical change or change in the method of operation of an emissions unit, emission facility, or stationary source that results in an increase in the emission of a regulated air pollutant.

A “change” is a change to permit terms or conditions, in the absence of a modification as described above.

3) Is the proposed change or modification a title I modification? It is if the answer to any of the following is “yes”:

3a) Is the proposed change or modification subject to New Source Review? Use and submit Forms CH-04, and CH-04a or CH-04b, as applicable.

- ☐ Yes
☒ No

3b) Is the proposed change or modification a modification or reconstruction as defined for New Source Performance Standards? Use and submit Form CH-05.

- ☐ Yes
☒ No

3c) Is the proposed change or modification a hazardous air pollutant modification under Part 61 National Emission Standards for Hazardous Air Pollutants (NESHAPs)? Use and submit Form CH-06.

- ☐ Yes
☒ No

3d) Is the proposed change or modification defined as construction or reconstruction under Part 63 NESHAPs? Use and submit Form CH-07.

- ☐ Yes
☒ No

4) Does this modification change any permit conditions or amend existing permit requirements related to **monitoring, reporting, or recordkeeping** other than adding new requirements, eliminating the requirements if they are rendered meaningless because they apply to emissions that will no longer occur, or changing test methods if both the new and the old test methods are considered valid for the pollutant and source category (Minn. R. 7007.1500, subp. 1(A))?

- ☒ Yes. Use and submit Form CD-01 and/or CD-05 to document such requirements.
☐ No

5) Does this modification establish or amend any **source-specific permit condition** that is required to be based on a case-by-case determination of an emissions limit or standard, an ambient impacts analysis, visibility, or increment analysis (e.g., a modeling-based limit, the requirement to operate a specific control device for a specific emission unit, specific operating parameters for a control device, a specific control efficiency, Best Available Control Technology (BACT), Maximum Achievable Control Technology (MACT), etc.) (Minn. R. 7007.1500, subp. 1(B))?

- ☒ Yes. Use and submit Form CD-01 and/or CD-05 to document such conditions.
☐ No

- 6) Does this modification establish or amend any permit terms or conditions for which there is no underlying applicable requirement and that you have assumed to avoid an applicable requirement to which you would otherwise be subject? Such limits are usually synthetic minor limitations such as a limit on hours of operation. Please note that if you would like to add equipment under an existing emissions cap or limit, and the permit does not explicitly pre-authorize such additions, that is considered amending the limit or emissions cap. (Minn. R. 7007.1500, subp. 1(C)).
- ☒ Yes. Use and submit Form CD-01 and/or CD-05 to document such conditions.
☐ No
- 7) Does this modification establish, amend, renew, or distribute a **Plantwide Applicability Limit** (PAL) under 40 CFR § 52.21(aa)? (This is only available to existing major sources under New Source Review.)
- ☐ Yes. Use and submit Forms PAL-01 (and the forms referenced within PAL-01) and CD-01 to document conditions. (As of the date of this form, the PAL cover page (PAL-01) and the form for determination of a PAL (PAL-02) have been completed. The remaining forms for renewal, expiration allocation, and increasing a PAL, are not yet available.)
☒ No
- 8) Is this modification subject to classification as a **major permit amendment under any other agency rule**?
- ☐ Yes
☒ No
- 9) Does this modification seek to establish or amend a federally enforceable emission cap (such as a synthetic minor limit which limits hours of operation) which avoids classification as a part 70 source?
- ☐ Yes. Use and submit Form CD-01 and/or CD-05 to document conditions.
☒ No

If you answered "Yes" to one or more of the above questions, a major permit amendment is required.



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

CH-04

**Determination of New Source Review Status
Air Quality Permit Program**

Doc Type: Permit Application

1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc.

3) Is your facility defined as one of the following types of facilities?

Some standard industrial classification (SIC) code(s) applying to specific categories are given in parentheses to assist you in classifying your facility. The SIC codes provided are not meant to be an exhaustive list of facilities included in the category.

- Coal Cleaning Plants-With Thermal Dryers
- Portland Cement Plants (3241)
- Iron and Steel Mills (3312)
- Primary Copper Smelters (3331)
- Hydrofluoric Acid Plants (2819, 2899)
- Nitric Acid Plants (2873)
- Lime Plants (3274)
- Coke Oven Batteries (3312)
- Carbon Black Plants (Furnace Process, 2895)
- Fuel Conversion Plants
- Secondary Metal Production Plants (334X)
- Fossil-Fuel Boilers (or combination thereof) totaling more than 250 MMBtu/hr heat input
- Taconite Ore Processing Plants (1011)
- Charcoal Production Plants (2819, 2861)
- Kraft Pulp Mills (2611, 2621)
- Primary Zinc Smelters (3339)
- Primary Aluminum Ore Reduction Plants (3334)
- Municipal Incinerators Capable of Charging More Than 50 Tons of Refuse per Day
- Sulfuric Acid Plants (2819)
- Petroleum Refineries (2911)
- Phosphate Rock Processing Plants (1475)
- Sulfur Recovery Plants (2819)
- Primary Lead Smelters (3339)
- Sintering Plants*
- Chemical Process Plants (28XX)**
- Petroleum Storage & Transfer Units, Total Storage Capacity over 300,000 Barrels
- Glass Fiber Processing Plants
- Fossil Fuel-Fired Steam Electric Plants of more than 250 MMBtu/hr heat input

* *Processing of fine grain materials into coarser lumps (performed primarily on ores).*

***Does not include ethanol production facilities that produce ethanol by natural fermentation included in NAICS codes 325193 or 312140.*

- ☐ **Yes**, my facility is classified as one of the 28 sources listed above. A listed air emission source having a potential to emit (PTE) 100 tons per year (TPY) or more of any single regulated pollutant (except carbon dioxide equivalents (CO₂e)) is considered a major stationary source. For sources classified as one of the 28 listed, fugitive emissions must be included in the PTE. **For item 4 of this form, and for Form CH-04b if applicable, a 100-TPY emissions threshold must be used for all regulated pollutants except CO₂e; for CO₂e, the threshold is 100,000 TPY.**
- ☒ **No**, my facility is not classified as one of the 28 sources listed above. An air emission source not classified as one of the 28 sources listed above and having the PTE 250 TPY or more of any single regulated pollutant (except CO₂e) is considered a major stationary source. **For item 4 of this form, and for Form CH-04b if applicable, a 250-TPY emissions threshold must be used for all regulated pollutants except CO₂e; for CO₂e, the threshold is 100,000 TPY.**

4) Is your proposed change subject to regulation for greenhouse gas (GHG), as defined in 40 CFR § 52.21(b)(49)? To answer this question, you must complete Form CH-04c.

- ☐ **Yes.** Go to question 5.
- ☒ **No.** Go to question 6

5) Is the current federally enforceable PTE (including GHG) of your facility greater than or equal to the thresholds identified in question 3?

- ☐ **Yes.** Go to question 7.
- ☒ **No.** Go to question 9.

- 6) Is the current federally enforceable PTE (excluding GHG) of your facility greater than or equal to the thresholds identified in question 3, making your facility a major stationary source?
- ☐ **Yes.** Go to question 7.
- ☐ **No.** Go to question 9
- 7) Is your facility currently covered by a permit that contains a Plantwide Applicability Limit ("actuals PAL") as defined at 40 CFR § 52.21(aa)(2)(i) and (v)?
- ☐ **Yes.** Go to question 8.
- ☐ **No.** Go to question 9.
- 8) Are you able to continue to meet the emissions limits set by the Plantwide Applicability Limit after the project?
- ☐ **Yes.** New Source Review is not applicable to the proposed change/modification. You need not complete the remainder of this form. You must determine if an amendment is needed under Minn. R. 7007.1150 – 7007.1500.
- ☐ **No.** You must complete a Best Available Control Technology (BACT) analysis for all major and significant emissions units at your source. If installation of BACT still does not allow you to install the emission unit and maintain compliance with your PAL, you may apply for an increase in your PAL. Please see the Minnesota Pollution Control Agency fact sheet on PALs at <http://www.pca.state.mn.us/index.php/view-document.html?gid=2097> or Form PAL-05 (*not yet available as of the date of this form*), for guidance on increasing a PAL. Do not complete the remainder of this form.
- 9) **Synthetic Minor Source:** Are you proposing new or revised federally enforceable limits such that the **entire facility (including the proposed modification)** will become or remain a minor source?
- ☐ **Yes.** Submit an application for a major amendment. Refer to <http://www.pca.state.mn.us/zihyd8c> for guidance on setting limits. Put proposed limits and proposed compliance demonstration on Form CD-01. Do **not** complete Forms CH-04a or CH-04b.
- ☒ **No.** If you answered "Yes" to question 5 or question 6, go to Form CH-04a.
If you answered "No" to question 5 or question 6, go to Form CH-04b.



Minnesota Pollution Control Agency

520 Lafayette Road North
St. Paul, MN 55155-4194

CH-04b

Determination of Increases at Minor Sources Air Quality Permit Program

Doc Type: Permit Application

Instructions on page 4

1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578
2) Facility Name: Sanimax USA Inc.

Use this Form to calculate emissions increases at existing sources which are minor New Source Review (NSR) sources. If the facility is a major source under NSR, use Form CH-04a.

- 3) Refer to Question 4 on Form CH-04 or question C3 on Form GI-09C, as applicable. Is the proposed change subject to regulation for GHG?
- ☐ Yes – Include carbon dioxide equivalents (CO₂e) emissions when completing the tables on this form.
- ☒ No – Do not include CO₂e when completing the tables on this form – Leave the CO₂e entries blank, or enter “NA.”
- 4) Use Table 1 to document the potential emissions of the individual units, tanks, or fugitive sources affected by the proposed modification. See instructions for calculating emissions increases. Make additional copies of Table 1 if more than four units are affected. Summarize the total increases for each pollutant in Table 2. Attach your calculations.

Table 1

	EU 23			EU 23	
Pollutant	Potential emissions (tpy)	Potential emissions (tpy)	Potential emissions (tpy)	Potential emissions (tpy)	Total (tpy)
PM	2.32				2.32
PM ₁₀ (including condensables)	1.24				1.24
PM _{2.5} (including condensables)	1.24				1.24
NO _x	23.15				23.15
SO ₂	1.42				1.42
CO	13.35				13.35
Ozone (VOC)	1.42				1.42
Lead	8E-05				8E-05
Fluorides					
Sulfuric acid mist					
Total Reduced Sulfur including H ₂ S					
Total Reduced Sulfur Compounds including H ₂ S					
MWC Organics					
MWC Acid Gas					
MSW Landfill Gas					
Carbon dioxide equivalents (CO ₂ e)	NA				NA

Table 2 - Summary

Pollutant	Emissions from all units affected by the modification (from Table 1) (tpy)	Thresholds for minor sources ("No" to CH-04 question 5 or 6 or "No" to GI-09C question C4 or C5) (tpy)		Thresholds for major sources
		Answered "Yes" to CH-04 question 3 or GI-09C Section A	Answered "No" to CH-04 question 3 or GI-09C Section A	Significant Emission Rates for major sources (tpy)
PM	2.32	100	250	25 ⁵
PM ₁₀ (including condensables)	1.24	100	250	15
PM _{2.5} (including condensables)	1.24	100	250	10
NO _x	23.15	100	250	40
SO ₂	1.42	100	250	40
CO	13.35	100	250	100
Ozone (VOC)	1.42	100	250	40
Lead	8E-05	100	250	0.6
Fluorides		100	250	3
Sulfuric acid mist		100	250	7
Total Reduced Sulfur including H ₂ S		100	250	10
Total Reduced Sulfur Compounds including H ₂ S		100	250	10
MWC Organics ¹		100	250	10
MWC Acid Gas ²		100	250	0.0000035
MWC Metals ³		100	250	40
MSW Landfill Gas		100	250	15
CO ₂ e ⁴	NA	100,000	100,000	75,000

Note 1: MWC Organics means Municipal Waste Combustor Organics. These are defined as total tetra-thro-octa-chlorinated dibenzo-para-dioxins and dibenzofurans.

Note 2: MWC acid gases are measured as the sum of sulfur dioxide and hydrochloric acid.

Note 3: MWC Metals are measured as particulate matter.

Note 4: CO₂e is calculated as a weighted aggregate of carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, using the gases' global warming potentials. (Refer to the MPCA website at <http://www.pca.state.mn.us/ktqh126f> for instructions on calculating greenhouse gas emissions.)

Note 5: On July 31, 1987, the National Ambient Air Quality Standard for TSP (PM) was repealed and replaced with a standard for PM₁₀. The significant levels in this table are as they appear in the Code of Federal Regulations, March 1994. A source may not be required to comply with Nonattainment NSR for TSP increases above 25 tpy, but may be for PM₁₀ above 15 tpy.

5) Referring to Table 2, do the total emissions from new, modified, debottlenecked, and replacement units exceed the appropriate threshold for minor sources, for any pollutant?

☒ No. Done with this form. Attach all calculations and required documentation (as described within this form). If you were sent to this from Form GI-09C, go back to that form and answer "No" to the question of whether the proposed change or modification is subject to NSR.

☐ Yes. Go to question 6.

6) In Table 3, list each pollutant for which the minor source threshold is exceeded in Table 2. Then go to question 7.

Table 3 – Pollutant Status vs. Minor Source Thresholds

Pollutants exceeding the minor source threshold in Table 2:

- 7) Will you propose and accept a limit on every pollutant in Table 3 such that no minor source thresholds are exceeded? (Refer to the MPCA website at <http://www.pca.state.mn.us/zihyd8c> for information on how to determine and propose limits.)
- ☐ Yes. Go to question 8.
- ☐ No. The emissions of at least one pollutant exceed the threshold for minor sources. Go to question 10.
- 8) Briefly describe the limit(s) you are proposing to keep the emissions of all pollutants listed in Table 3 below its associated minor source threshold. Also include the limit(s) on Form CD-01, with your proposed method of demonstrating compliance. Then go to question 9.
- 9) You are done with this form. Attach all calculations and required documentation (as described within this form). If you were sent to this from Form GI-09C, go back to that form and answer "No" to the question of whether the proposed change or modification is subject to NSR.
- 10) The project is major for at least one pollutant.
Review Table 2. In Table 4, list each pollutant for which the total emissions from new, modified, debottlenecked, and replacement units exceed the associated major modification threshold for major sources. Then go to question 11.

Table 4 – Pollutant Status vs. Major Modification Thresholds

Pollutants exceeding the major source significant emission rate in Table 2

- 11) Will you propose and accept a limit on any pollutant in Table 4 such that it does not exceed its major source significant emission rate? (Refer to the MPCA website at <http://www.pca.state.mn.us/zihyd8c> for information on determining and proposing limits.)
- ☐ Yes. Go to question 12.
- ☐ No. The project is major for each pollutant listed in Table 4. Go to question 13.
- 12) Briefly describe the limit(s) you are proposing to keep the emissions of any pollutant listed in Table 4 below their significant emission rates. Also include the limit(s) on Form CD-01 with your proposed method of demonstrating compliance. Go to question 13.
- 13) In Table 5, list all pollutants that you have determined to be subject to PSD. This will include each pollutant in Table 3 and in Table 4 for which you did not limit emissions below the major source threshold in Table 2 (the significant emission rate).

Table 5 – Pollutants Subject to PSD



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

CH-04c

**Determination of Greenhouse Gas
Status under New Source Review
Air Quality Permit Program**

Doc Type: Permit Application

Instructions on page 5

- 1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578
- 2) Facility Name: Sanimax USA Inc.
- 3) Calculate the potential to emit (PTE) of greenhouse gases (GHG) emissions for your existing facility, before your proposed change, including the mass emissions of individual GHGs (columns a – f), the sum of the mass emissions of individual GHGs (column g), and the carbon dioxide equivalent (CO₂e, column h). Refer to the MPCA website at <http://www.pca.state.mn.us/ktqh126f> for guidance in calculating the individual mass emissions and the CO₂e. Complete your calculations on a spreadsheet; transfer the current PTE to Table 1 below, and include the calculation spreadsheet in your application package.

Table 1

a)	b)	c)	d)	e)	f)	g)	h)
Carbon Dioxide (CO ₂) (tpy)	Methane (CH ₄) (tpy)	Nitrous Oxide (N ₂ O) (tpy)	Hydrofluorocarbons (HFC) (tpy)	Perfluorocarbons (PFC) (tpy)	Sulfur Hexafluoride (SF ₆) (tpy)	Mass Sum of GHGs (tpy)	Carbon Dioxide Equivalent (CO ₂ e) (tpy)
54,874	1.71	1.00				54,876	55,220

- 4) Is the number you entered for CO₂e greater than 100,000 tpy?
- ☐ Yes. Go to question 5.
- ☒ No. Go to question 6.
- 5) Is the mass sum of the individual GHGs (column g) greater than either 100 tpy (if you answered “yes” to question 3 on Form CH-04 or Section A on Form GI-09C), or 250 tpy (if you answered “no” to question 3 on Form CH-04 or Section A on Form GI-09C)?
- ☐ Yes. Go to question 8. Do not answer questions 6 or 7 or complete Tables 2 or 3.
- ☐ No. Go to question 6.
- 6) Use Table 2 to document the emissions increase for individual units, tanks, or fugitive sources affected by the proposed modification. See instructions for calculating emissions increases. Make additional copies of Table 2 if more than four units are affected. Summarize the total increases for each pollutant in Table 3. Attach your calculations (both in an editable spreadsheet format, and a hard copy printout). Answer the question following Table 3.

Table 2

	EU 23			EU 23	
Pollutant	Potential emissions (tpy)	Potential emissions (tpy)	Potential emissions (tpy)	Potential emissions (tpy)	Total (tpy)
CO ₂	25,813				25,813
CH ₄	0.37				0.37
N ₂ O	1.59				1.59
HFC					
PFC					
SF ₆					
CO ₂ e	25,907				25,907

Table 3 - Summary

Pollutant	Potential Emissions ("Total" from Table 2) (tpy)	Thresholds making your change Subject to Regulation (tpy)	
		Answered "Yes" to CH-04 question 3	Answered "No" to CH-04 question 3
CO ₂	25,813	NA	NA
CH ₄	0.37	NA	NA
N ₂ O	1.59	NA	NA
HFC		NA	NA
PFC		NA	NA
SF ₆		NA	NA
Total Mass GHG (sum of above 6 numbers)	25,815	100	250
CO ₂ e	25,907	100,000	100,000

Is the number you entered for CO₂e in Table 3 greater than or equal to 100,000 tpy?

☐ Yes. Go to question 7.

☒ No. Your proposed change is not Subject to Regulation for GHG under New Source Review. You are done with this form. Return to the form that directed you here (Form CH-04 or Form GI-09C) and answer "No" to the question of whether the proposed change or modification is subject to regulation for GHG.

7) Are the total mass emissions (sum of the masses of the individual GHGs, excluding global warming potentials) greater than or equal to the applicable threshold, shown in the two columns on the right?

☐ Yes. Your proposed change is Subject to Regulation for GHG under New Source Review. You are done with this form. Return to the form that directed you here (Form CH-04 or Form GI-09C) and answer "Yes" to the question of whether the proposed change or modification is subject to regulation for GHG.

☐ No. Your proposed change is not Subject to Regulation for GHG under New Source Review. You are done with this form. Return to the form that directed you here (Form CH-04 or Form GI-09C) and answer "No" to the question of whether the proposed change or modification is subject to regulation for GHG.

8) Use Table 4 to document the emissions increase for individual units, tanks, or fugitive sources being modified or debottlenecked, or that are replacing an existing unit, using the calculation method found in 40 CFR § 52.21(a). See instructions for calculating emissions increases; the method is different depending on the type of unit. Complete a separate Table 4 for each modified, replacement, or debottlenecked emission unit. If you base your calculations on projected actual emissions (rather than future potential emissions), include (in the space provided at the end of Table 4) the title and date of the business document on which you based your projections. If you exclude emissions from your projected actual emissions, include (in the space provided at the end of Table 1) a description of the excluded emissions, including an explanation of why these were excluded. Attach an additional sheet if necessary. Make additional copies if more than three units are affected. Summarize the total increases for each pollutant in Table 5. Attach your calculations.

Table 4

☐ Modified		☐ Replacement		☐ Debottlenecked	
Pollutant	☐ Projected Actual* or ☐ Future Potential Emissions (tpy)	Baseline Actual Emissions (tpy)	Exclusions from Projected Actuals (tpy)	Increase (tpy)	Baseline period (dates)

* Title/date of document(s) used as basis for projected actuals: _____

** Description of emissions excluded from projected actuals:

Table 4

☐ Modified ☐ Replacement ☐ Debottlenecked					
Pollutant	☐ Projected Actual* or ☐ Future Potential Emissions (tpy)	Baseline Actual Emissions (tpy)	Exclusions from Projected Actuals (tpy)	Increase (tpy)	Baseline period (dates)
CO ₂					
CH ₄					
N ₂ O					
HFC					
PFC					
SF ₆					
CO ₂ e					

* Title/date of document(s) used as basis for projected actuals:

** Description of emissions excluded from projected actuals:

Table 4

☐ Modified ☐ Replacement ☐ Debottlenecked					
Pollutant	☐ Projected Actual* or ☐ Future Potential Emissions (tpy)	Baseline Actual Emissions (tpy)	Exclusions from Projected Actuals (tpy)	Increase (tpy)	Baseline period (dates)
CO ₂					
CH ₄					
N ₂ O					
HFC					
PFC					
SF ₆					
CO ₂ e					

* Title/date of document(s) used as basis for projected actuals:

** Description of emissions excluded from projected actuals:

Table 5 – Summary of Table 4 Results

Pollutant	Increase (tpy)	Increase (tpy)	Increase (tpy)	Increase (tpy)	Increase (tpy)	Total Increase (tpy)
CO ₂						
CH ₄						
N ₂ O						
HFC						
PFC						
SF ₆						

CO ₂ e						
-------------------	--	--	--	--	--	--

- 9) Use Table 6 to document the potential emissions of each *new* emission unit constructed or installed. Copy this table if more than five units are added. Attach your calculations.

Table 6

						Total Increase (tpy)
Pollutant	Increase (tpy)	Increase (tpy)	Increase (tpy)	Increase (tpy)	Increase (tpy)	
CO ₂						
CH ₄						
N ₂ O						
HFC						
PFC						
SF ₆						
CO ₂ e						

- 10) Project Totals

Table 7 – Project Summary

Column A	Column B	Column C	Column D	Column E
Pollutant	Emissions increases from modified, replacement, or debottlenecked units (from Table 5) (tpy)	Emissions from new units (from Table 6) (tpy)	Total Increase (tpy)	Significant Thresholds for major sources (tpy)
CO ₂				0
CH ₄				0
N ₂ O				0
HFC				0
PFC				0
SF ₆				0
CO ₂ e				75,000

- 11) Is the total increase of CO₂e (Column D of Table 7) greater than or equal to 75,000 tpy?
- ☐ Yes. Your proposed change is Subject to Regulation for GHG under New Source Review. You are done with this form. Return to the form that directed you here (Form CH-04 or Form GI-09C) and answer “Yes” to the question of whether the proposed change or modification is subject to regulation for GHG.
- ☐ No. Your proposed change is not Subject to Regulation for GHG under New Source Review. You are done with this form. Return to the form that directed you here (Form CH-04 or Form GI-09C) and answer “No” to the question of whether the proposed change or modification is subject to regulation for GHG.

Instructions for Form CH-04c

- 1a) AQ Facility ID No.** -- Fill in your Air Quality (AQ) Facility Identification (ID) Number (No.). This is the first eight digits of the permit number for all permits issued under the operating permit program.
- 1b) AQ File No.** -- Fill in your AQ File Number. This number can be found in the “cc” line of correspondence from the Minnesota Pollution Control Agency (MCPA).
- 2) Facility Name** -- Enter your facility name.



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

CH-05

**Applicability of NSPS
Air Quality Permit Program**

Doc Type: Permit Application

Instructions on Page 3

Complete this form to determine if the proposed change or modification results in new applicability of a New Source Performance Standard listed in Table 1.

1a) AQ Facility ID No.: 03700070 **1b)** AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3) Is there a New Source Performance Standards (NSPS) for a source category which includes the unit(s) you are installing, modifying, or reconstructing?

☒ Yes. Go to question 4

☐ No. Done with this Form. Answer "No" to question 3b) on Form CH-03.

4) Complete Question 4a) – 4c) for each new, modified, or reconstructed unit which may be subject to an NSPS following the proposed project. (Copy as necessary.)

4a) Unit	4b) NSPS Subpart(s) that may apply after project	4c) Do all of the NSPS listed in column 4b) for the unit listed in column 4a) currently apply (prior to the proposed project)? If this is a new unit, the answer is "no."	
EU023	Dc	☐ Yes – done with this unit	☒ No
		☐ Yes – done with this unit	☐ No
		☐ Yes – done with this unit	☐ No
		☐ Yes – done with this unit	☐ No
		☐ Yes – done with this unit	☐ No

5) Did you check "no" in column 4c) for **any** unit in the table in question 4)?

☐ No. This indicates that NSPS currently applies to all units and there will be no newly applicable NSPS as a result of the proposed project. Done with this form. Answer "no" to question 3b) on Form CH-03.

☒ Yes. Complete the remainder of this form for each unit for which you checked "no" in the last column of the table in question 4.

6) Installing a new unit to which the NSPS will apply?

☐ No. Go to Question 7).

☒ Yes – Complete Questions 6a) – 6e) for each new unit. (Copy as necessary.)

6a) Emission Unit Number: EU023

6b) Emission Unit/Equipment Description: 37 MMBtu/hr natural gas boiler

6c) Stack/Vent Number: SV019

6d) Date of Equipment Manufacture or Installation: TBD (Month/Date/Year)

6e) Attach a copy of the applicable 40 CFR pt. 60 subpart, and subpart A, with the applicable sections highlighted. Use Form CD-01 to document the proposed methods of compliance.

7) Reconstructing an existing unit to which an NSPS will apply?

☒ No. Go to Question 8).

☐ Yes – Complete Questions 7a) – 7e) (next page) for each reconstructed unit. (Copy as necessary.)

- 7a) Emission Unit Number: _____
- 7b) Emission Unit/Equipment Description: _____
- 7c) Stack/Vent Number: _____
- 7d) Date of Reconstruction (expected): _____ (Month/Date/Year)
- 7e) Attach a copy of the applicable 40 CFR pt. 60 subpart, and subpart A, with the applicable sections highlighted. Use Form CD-01 to document the proposed methods of compliance.

8) Physical change or modification to an existing unit to which the NSPS might apply?

- ☒ No. Go to Question 10).
- ☐ Yes – Complete Question 8a) for each modified unit. (Copy as necessary.)

8a) Emission Unit ID No.: _____

Pollutant(s) regulated by the NSPS	Emission Rate after change (lb/hr)	Emission Rate before change (lb/hr)	Change in Emission Rate (lb/hr)
☐ PM			
☐ PM ₁₀			
☐ PM _{2.5}			
☐ NO _x			
☐ SO ₂			
☐ CO			
☐ VOC			
☐ Lead			

9) Is there an increase in the hourly emission rate of any of the pollutants regulated by the NSPS?

- ☐ No. Go to Question 10).
- ☐ Yes – Complete Questions 9a) – 9d) for each modified unit. (Copy as necessary.)

- 9b) Emission Unit/Equipment Description: _____
- 9b) Stack/Vent Number: _____
- 9c) Date of Modification (expected): _____ (Month/Date/Year)
- 9d) Attach a copy of the applicable 40 CFR pt. 60 subpart, and subpart A, with the applicable sections highlighted. Use Form CD-01 to document the proposed methods of compliance.

10) Check all that apply

- ☒ If you answered either “yes” or “no” to question 6) **and** “no” to question 7) **and** “no” to question 8) or question 9), a major amendment is not needed under Minn. R. 7007.1500, subp. 3a. Answer “no” to Question 3b) on Form CH-03. Another type of permit amendment may still be required.
- ☐ If you answered “yes” or “no” to question 6), **and either** “yes” to question 7) **or** “yes” to questions 8) and 9), this change or modification requires a major amendment under Minn. R. 7007.1500, subp. 3a. Answer “yes” to Question 3b) on Form CH-03.
- ☐ If you answered “yes” to question 6), 7), or 9), **but the total facility potential-to-emit remains below all permit thresholds**, review Minn. R. 7007.0250 – 7007.0300 to determine if a permit is needed.



AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT CHANGE FORM **CH-06**
APPLICABILITY OF PART 61 NESHAP
(FORMERLY MOD-06 APPLICABILITY OF PART 61 NESHAP)
03/31/04

Complete this form to determine if the proposed change or modification results in new applicability of a Part 61 NESHAP listed in Table 1.

1a) AQ Facility ID No.: 03700070

1b) AQ File No. 578

2) Facility Name.: Sanimax USA Inc

3) Is there a Part 61 NESHAP for a source category which includes the unit(s) you are installing, modifying, or reconstructing?

☐ Yes. Go to question 4

☒ No. Done with this Form. Answer "No" to question 3c) on Form CH-03.

4) Complete Question 4a) – 4c) for each new, modified, or reconstructed unit which may be subject to a Part 61 NESHAP following the proposed project. (Copy as necessary.)

4a) Unit	4b) Part 61 Subpart(s) that may apply after project	4c) Do all of the NESHAPs listed in column 4b) for the unit listed in column 4a) currently apply (prior to the proposed project)? If this is a new unit, the answer is "no."
		☐ Yes – done with this unit ☐ No
		☐ Yes – done with this unit ☐ No
		☐ Yes – done with this unit ☐ No
		☐ Yes – done with this unit ☐ No
		☐ Yes – done with this unit ☐ No

5) Did you check "no" in column 4c) for any unit in the table in question 4)?

☐ No. This indicates that NESHAP currently applies to all units and there will be no newly applicable NESHAPs as a result of the proposed project. Done with this form. Answer "no" to question 3c on Form CH-03.

☐ Yes. Complete the remainder of this form for each unit for which you checked "no" in the last column of the table in question 4.

6) Installing new equipment which will cause a Part 61 NESHAP to apply?

☐ No - Go to question 7).

☐ Yes – Complete 6a) – 6c) for each new unit. (Copy as necessary.) Use Form CD-01 to document the proposed methods of compliance. Include a highlighted photocopy of the standard.

6a)	Emission Unit Number	
6b)	Emission Unit/Equipment Description	
6c)	Stack/Vent Number	



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

CH-07

**Applicability of Part 63 NESHAP for Amendments
Air Quality Permit Program**

Doc Type: Permit Application

AQ Facility ID No.: 03700070

AQ File No.: 578

Facility Name: Sanimax USA Inc

- 1) Are there or will there be Hazardous Air Pollutants (HAPs) emissions (listed on Table A) from any source affected by the proposed project?
☐ No. Done with this form. Answer "No" to Question 3d on Form CH-03.
☒ Yes. Go on to Question 2 of this form.

- 2) Are you proposing to install new HAP-emitting sources, or reconstruct existing equipment that will emit HAPs following the reconstruction? (This specifically means "reconstruction" as defined at 40 CFR § 63.2 – if you modify existing equipment without meeting the definition of "reconstruction," the answer to this question is "No.")
☐ No. Done with this form. Answer "No" to Question 3d on Form CH-03.
☒ Yes. Go on to Question 3 of this form.

- 3) Is the currently-permitted facility a major HAP source (considering potential emissions and all existing federally enforceable permit conditions)?
☒ No. Go on to Question 4.
☐ Yes. Go to Question 7.

- 4) Will the new or reconstructed items (those affected by the modification) have the potential to emit 10 or more tons per year of any individual HAP, or 25 or more tons per year of total HAPs, before considering any limits the source may be subject to or limits you may propose later in this form?
☒ No. Go on to Question 5.
☐ Yes. Go to Question 6.

- 5) Will the facility as modified be a major source of HAP emissions after your proposed change, before considering any limiting conditions you may propose later in this form?
☒ No. Go to Question 10.
☐ Yes. Go on to Question 6.

- 6) It is possible to avoid becoming a major HAP source by proposing federally enforceable permit conditions to limit your potential HAP emissions from the entire facility (as modified) to less than 10 tons per year for each HAP and/or 25 tons per year for all HAPs combined. Do you want to accept permit limitations on HAPs to avoid becoming a major HAP source?
☐ No. Go on to question 7.
☐ Yes. **Briefly describe the limitations** you would be willing to accept so that your HAP emissions will be less than 10 tons per year for each HAP and less than 25 tons per year for all HAPs combined (use a separate sheet if needed). Description must include each of the HAP pollutants. Include your proposed limit, monitoring, recordkeeping, and reporting on Form CD-01. You must answer "Yes" to Question 6 on Form CH-03. Then go to Question 10 of this form.

- 7) Will any of the new or reconstructed items be subject to any of the standards for major source categories listed in Table B? Also consider whether any existing, non-modified parts of the facility are subject to one or more of the standards listed in Table B; if so, and the standard is not already included in your existing permit, include those sources and standards here as well.

- ☐ No. Go on to Question 8.
☐ Yes. List the source categories applicable to each new, reconstructed, or existing HAP-emitting equipment.

Source	(N)ew, (R)econstructed, or (E)xisting? (Check one)	Applicable Source Category (Subpart or Title)	Compliance Date
	☐ N ☐ R ☐ E		
	☐ N ☐ R ☐ E		
	☐ N ☐ R ☐ E		
	☐ N ☐ R ☐ E		

For each standard listed above, attach a copy of the National Emission Standards for Hazardous Air Pollutant (NESHAP) standard with the applicable parts highlighted. Also attach a copy of Subpart A with the applicable portions highlighted. If the applicable standard offers more than one compliance option, make it clear which one you are choosing.
Go on to Question 8.

- 8) Will the new or reconstructed items (those affected by the proposed modification) have the potential to emit 10 or more tons per year of any individual HAP, or 25 or more tons per year of total HAPs, before considering any limits the source may be subject to?

- ☐ No. Done with this form. Answer "No" to Question 3d on Form CH-03.
☐ Yes. Go on to Question 9 of this form. Answer "Yes" to Question 3d on Form CH-03.

- 9) Will any of the new or reconstructed items **not** be subject to any of the standards for major source categories listed in Table B?

- ☐ No. Done with this form.
☐ Yes. List them here. Done with this form.

HAP-emitting units with no applicable source category in Table B.

For those HAP-emitting units listed above, you must propose a case-by-case MACT determination meeting the requirements of 40 CFR § 63.43. Contact the Minnesota Pollution Control Agency (MPCA) for information about proposing a case-by-case MACT determination for approval.

- 10) Some non-major HAP sources will be subject to requirements of NESHAPs called "area source" NESHAPs. Will the proposed new or reconstructed units belong to any of the area source categories listed below?

- ☐ No. Done with this form. Answer "No" to Question 3d on Form CH-03.
☒ Yes. Place a check in the box next to that category, and read the specified NESHAP for Source Categories to determine all applicable requirements for area sources. Attach a copy of each applicable subpart of the NESHAP for area source categories, and highlight the applicable requirements in each applicable subpart. Done with this form. Answer "No" to Question 3d on Form CH-03.

- ☐ Acrylic and Modacrylic Fibers Production, 40 CFR § 63 Subpart LLLLLL
☐ Asphalt Processing and Asphalt Roofing Manufacturing, 40 CFR § 63 Subpart AAAAAA
☐ Carbon Black Production, 40 CFR § 63 Subpart MMMMMM
☐ Chemical Manufacturing Area Sources, 40 CFR § 63 Subpart VVVVVV
☐ Chemical Manufacturing: Chromium Compounds, 40 CFR § 63 Subpart NNNNNN
☐ Chemical Preparations Industry, 40 CFR § 63 Subpart BBBB BB
☐ Chromic acid anodizing (**Chromium Electroplating**), 40 CFR § 63 Subpart N
☐ Clay Ceramics Manufacturing, 40 CFR § 63 Subpart RRRRRR
☐ Commercial dry cleaning (Perc) transfer machines, 40 CFR § 63 Subpart M
☐ Commercial sterilization facilities, 40 CFR § 63 Subpart O
☐ Decorative chromium electroplating (**Chromium Electroplating**), 40 CFR § 63 Subpart N

- ☐ Electric Arc Furnace Steelmaking Facilities, 40 CFR § 63 Subpart YYYYYY
- ☐ Ferroalloys Production Facilities, 40 CFR § 63 Subpart YYYYYY
- ☐ Flexible Polyurethane Foam Production and Fabrication, 40 CFR § 63 Subpart OOOOOO
- ☐ Gasoline Dispensing Facilities, 40 CFR § 63 Subpart CCCCCC
- ☐ Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities, 40 CFR § 63 Subpart BBBB
- ☐ Glass Manufacturing, 40 CFR § 63 Subpart SSSSSS
- ☐ Gold Mine Ore Processing and Production, 40 CFR § 63 Subpart EEEEEEE
- ☐ Halogenated solvent cleaners (Degreasing Organic Cleaners), 40 CFR § 63 Subpart T
- ☐ Hard chromium electroplating (**Chromium Electroplating**), 40 CFR § 63 Subpart N
- ☐ Hospital Sterilizers using Ethylene Oxides, 40 CFR § 63 Subpart WWWW
- ☒ Industrial, Commercial, and Institutional Boilers and Process Heaters – Area Sources. 40 CFR § 63 Subpart JJJJJ
- ☐ Iron and Steel Foundries Area Sources, 40 CFR § 63 Subpart ZZZZ
- ☐ Lead Acid Battery Manufacturing, 40 CFR § 63 Subpart PPPPP
- ☐ Metal Fabrication and Finishing Sources, 40 CFR § 63 Subpart XXXXX
- ☐ Nonferrous Foundries: Aluminum, Copper, and Other, 40 CFR § 63 Subpart ZZZZZ
- ☐ Oil and natural gas production, 40 CFR § 63 Subpart HH
- ☐ Paint Stripping and Miscellaneous Surface Coating Operations at Area Sources, 40 CFR § 63 Subpart HHHHH
- ☐ Paints and Allied Products Manufacturing, 40 CFR § 63 Subpart CCCCCC
- ☐ Plating and Polishing Operations, 40 CFR § 63 Subpart WWWW
- ☐ Polyvinyl Chloride and Copolymers Production, 40 CFR § 63 Subpart DDDDD
- ☐ Prepared Feeds Manufacturing, 40 CFR § 63 Subpart DDDDDDD
- ☐ Primary Copper Smelting, 40 CFR § 63 Subpart EEEEE
- ☐ Primary Nonferrous Metals: Zinc, Cadmium, and Beryllium, 40 CFR § 63 Subpart GGGGG
- ☐ Reciprocating Internal Combustion Engines, 40 CFR § 63 Subpart ZZZZ
- ☐ Secondary aluminum processing, 40 CFR § 63 Subpart RRR
- ☐ Secondary Copper Smelting, 40 CFR § 63 Subpart FFFFF
- ☐ Secondary Nonferrous Metals Processing (Brass, Bronze, Magnesium, Zinc), 40 CFR § 63 Subpart TTTTT
- ☐ Wood Preserving, 40 CFR § 63 Subpart QQQQQ



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

CH-11

Crossing Permit Thresholds
Air Quality Permit Program

Doc Type: Permit Application

Instructions on Page 2

1a) AQ Facility ID No.: 03700070 **1b)** AQ File No.: 578

2) Facility Name: Sanimax USA Inc.

Use this form to determine if the proposed changes cause the facility to become subject for the first time to the requirement to obtain either a State or a Part 70 permit. Please attach your documentation.

Total Facility PTE before change	Total Facility PTE after change	Action required
☐ Below all permit thresholds	Remains below all permit thresholds and the change does not cause the source or any part to become subject to an NSPS (40 CFR pt. 60) or a Part 61 NESHAP (40 CFR pt. 61).	No permit action required
☐ Below all permit thresholds	Remains below all permit thresholds but the change causes the source or any part to become subject to an NSPS (40 CFR pt. 60) or a Part 61 NESHAP (40 CFR pt. 61).	Apply for and receive a permit only for those sources subject to that regulation. Check applicability of registration permit and general permit.
☐ Below all permit thresholds	Exceeds a threshold for a State permit but not for a Part 70 permit.	Apply for and receive a permit to construct before beginning actual construction. (See instructions for details.)
☐ Below all permit thresholds or above a state permit threshold but below all Part 70 thresholds	Exceeds a threshold for a Part 70 permit	
☐ Above a State permit threshold but below all Part 70 thresholds	Remains above a State permit threshold but below all Part 70 thresholds	You may amend your existing permit. However, if you do not currently hold an operating permit, you must apply for and receive either a State or Part 70 permit prior to beginning actual construction.
☒ Above Part 70 Threshold	Remains above Part 70 Threshold	



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

CH-13

**Applicability Of State Rules
Air Quality Permit Program**

Doc Type: Permit Application

1a) AQ Facility ID No.: 03700070

1b) AQ File No. 578

2) Facility Name: Sanimax USA Inc.

Some businesses and activities in Minnesota are subject to the following rules. Read each question to determine if the rule applies to the equipment or processes you are installing or modifying. If so, be sure to include the rule in Form CD-01, if you are required to fill it out for this application.

3) Minnesota Standards of Performance for Stationary Sources (Minn. R. ch. 7011)

3a) Will you be installing or modifying equipment that meets the following definition?

"A furnace, boiler or other combustion equipment in Minnesota which burns fossil fuel for the purpose of producing steam, hot water, hot air, or other hot liquid, gas, or solid, where the smoke doesn't have direct contact with the heated medium for which another standard of performance has not been promulgated."

☐ No, my new or modified equipment **is not** subject to Minn. R. 7011.0500-7011.0551. Go to question 3b).

☒ Yes. Is or will the unit(s) be subject to a federal New Source Performance Standard (as identified on Form CH-05)?

☒ Yes, my new or modified equipment **is not** subject to Minn. R. 7011.0500-7011.0551. Go to question 3b).

☐ No, my new or modified equipment **is** subject to Minn. R. 7011.0500-7011.0551. Standards of Performance for Indirect Heating Fossil-Fuel Burning Equipment. (Read the rule to determine the specific requirements that apply.) List the subject unit(s):

3b) Is your new or modified equipment type or process equipment found in Table 3? This table contains only state-specific requirements; it does not contain state rules that incorporate federal rules by reference.

☒ No, none of the Minnesota Rules listed in Table 3 apply to my new or modified equipment. Go to question 4).

☐ Yes, my new or modified equipment may be subject to the rule associated with it in Table 3. Read the associated rule to see if it applies.

3c) After reading through Table 3 and any rule that may apply to your proposed change, list the ones that do apply in Table 1. Again, Table 3 contains only state-specific requirements; it does not contain state rules that incorporate federal rules by reference. You do not need to list the state rules that incorporate federal rules by reference. You do not need to list the Standards of Performance for Indirect Heating Fossil-Fuel Burning Equipment again, if it applies (see 3a, above).

Table 1: New/Modified Equipment Subject to Minnesota Standards of Performance

Emission Source ID Number	Minnesota Rule Part that Applies	What the Rule Part Applies to (Whole facility or Specific Piece of Equipment)

4) **Minnesota Acid Deposition Control** (Minn. R. 7021.0050)

- 4a) Does your facility generate electricity?
☒ No. My facility is not subject to Acid Deposition Control Requirements. Go to question 5.
☐ Yes. Go to question 4b).
- 4b) Does your facility contain indirect heating equipment with a rated heat input of more than 5,000 million BTUs per hour?
☐ No. Go to question 4c).
☐ Yes. My facility (and possibly my proposed change) is subject to Acid Deposition Control Requirements.
- 4c) If your facility is an electric utility, is the total generating capacity of all the electric generating facilities in Minnesota which are owned by your facility's parent company more than 1,000 megawatts?
☐ No. My facility is not subject to Acid Deposition Control Requirements.
☐ Yes. My facility (and possibly my proposed change) is subject to Acid Deposition Control Requirements.

5) **Standards of Performance for Industrial Process Equipment** (Minn. R. 7011.0700 - 7011.0735)

- 5a) Are you installing or modifying any industrial process equipment on-site that may generate any air contaminant in any amount and is not regulated by a federal New Source Performance Standard or MN Rules Standard of Performance?
☐ Yes. List the units in Table 2, then go to item 5b).
☒ No, my new or modified equipment is not subject to the Industrial Process Equipment rule. Go to question 6).
- 5b) **Opacity Standard**
(Note: Opacity is a measure of visible emissions or how much of the view is obscured by stack emissions. The emissions causing opacity are often smoke or dust.)
- For industrial process equipment which was *in operation before July 9, 1969*, the equipment shall not exhibit greater than 20 percent opacity, except for one six-minute period per hour of not more than 60 percent opacity. An exceedance of this opacity standard occurs whenever any one-hour period contains two or more six-minute periods during which the average opacity exceeds 20 percent or whenever any one-hour period contains one or more six-minute periods during which the average opacity exceeds 60 percent.
 - For industrial process equipment which was *not in operation before July 9, 1969*, the equipment shall not exhibit greater than 20 percent opacity.
- 5c) Does any of the industrial process equipment you listed in Table 2 have particulate control equipment with a collection efficiency of at least 99 percent if it was in operation before July 9, 1969, or 99.7 percent if it was not in operation before July 9, 1969?
☐ No. Go to question 5d).
☐ Yes. These units are considered to be in compliance with the remaining requirements of this rule.
- For those units meeting this criterion which were in operation before July 9, 1969, complete Table 2 by checking the box labeled "Collection Efficiency > 99%."
 - For those units meeting this criterion which were not in operation before July 9, 1969, complete Table 2 by checking the box labeled "Collection Efficiency > 99.7%."
 - Then, if there are units listed in Table 2 which are not controlled by control equipment with a collection efficiency of 99% or 99.7% (as applicable), go on to question 5d).
- 5d) Has it been demonstrated that the operation of the entire facility in compliance with all ambient air quality standards? This is typically shown through some level of computer dispersion modeling.
☐ Yes. Go to question 5e).
☐ No. Skip to item 5i).
- 5e) Is the facility located outside of the seven county Minneapolis-St. Paul metropolitan region?
☐ Yes. Go to question 5f)
☐ No. Skip to item 5i).
- 5f) Is the facility located outside of the city of Duluth?
☐ Yes. Go to question 5g).
☐ No. Skip to item 5i).
- 5g) Is the facility located at least 1/4 mile from any residence or public roadway?
☐ Yes. Go to question 5h).
☐ No. Skip to item 5i).
- 5h) Answer this question individually for each remaining unit listed in Table 2 (those which were not identified in item 5c) as being controlled by control equipment having a control efficiency of 99% or 99.7% (as applicable)). Does the industrial process equipment have particulate control equipment with a collection efficiency of at least 85 percent?
☐ Yes, the unit is considered to be in compliance with the remaining requirements of this rule. For each unit for which you can answer "yes" to question 5h), complete Table 2 by checking the box labeled "Outside MSP & Duluth, 1/4 mile from roads/residences, collection efficiency > 85%." Answer question 5h) for each remaining unit on Table 2.
☐ No. For each unit for which you answered "No" to question 5h), complete Table 2 as described in item 5i). Then go to question 6).
- 5i) Complete Table 2 for all remaining industrial process equipment listed (those which were not identified in question 5c) as being controlled by control equipment having a control efficiency of 99% or 99.7% (as applicable)). Use Table 4 to

determine the particulate limit in either pounds per hour (lb/hr) or grains per dry standard cubic foot (gr/dscf). Then go to question 6).

Table 2: New/Modified Equipment Subject to Industrial Process Equipment Rule

Equipment Subject to Industrial Process Equipment Rule (list EU number(s))	Applicable Particulate Limit
_____ ☐ In operation before July 9, 1969 _____ ☐ Not in operation before July 9, 1969	☐ Collection Efficiency > 99% ☐ Collection Efficiency > 99.7% ☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscf ☐ _____ lb/hr
_____ ☐ In operation before July 9, 1969 _____ ☐ Not in operation before July 9, 1969	☐ Collection Efficiency > 99% ☐ Collection Efficiency > 99.7% ☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscf ☐ _____ lb/hr
_____ ☐ In operation before July 9, 1969 _____ ☐ Not in operation before July 9, 1969	☐ Collection Efficiency > 99% ☐ Collection Efficiency > 99.7% ☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscf ☐ _____ lb/hr
_____ ☐ In operation before July 9, 1969 _____ ☐ Not in operation before July 9, 1969	☐ Collection Efficiency > 99% ☐ Collection Efficiency > 99.7% ☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscf ☐ _____ lb/hr
_____ ☐ In operation before July 9, 1969 _____ ☐ Not in operation before July 9, 1969	☐ Collection Efficiency > 99% ☐ Collection Efficiency > 99.7% ☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscf ☐ _____ lb/hr
_____ ☐ In operation before July 9, 1969 _____ ☐ Not in operation before July 9, 1969	☐ Collection Efficiency > 99% ☐ Collection Efficiency > 99.7% ☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscf ☐ _____ lb/hr
_____ ☐ In operation before July 9, 1969 _____ ☐ Not in operation before July 9, 1969	☐ Collection Efficiency > 99% ☐ Collection Efficiency > 99.7% ☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscf ☐ _____ lb/hr
_____ ☐ In operation before July 9, 1969 _____ ☐ Not in operation before July 9, 1969	☐ Collection Efficiency > 99% ☐ Collection Efficiency > 99.7% ☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscf ☐ _____ lb/hr

☐ In operation before July 9, 1969 ☐ Not in operation before July 9, 1969	☐ Collection Efficiency > 99% ☐ Collection Efficiency > 99.7% ☐ Outside MSP & Duluth, ¼ mile from roads/residences, collection efficiency > 85% ☐ _____ gr/dscf ☐ _____ lb/hr
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6) Waste Combustors (Minn. R. 7011.1201-7011.1290)

Note: Depending on the type of waste combustor you operate, you may be instructed to fill out one or more of the following forms:

- WC-01 -- Required if you determine that your waste combustor requires a permit.
- WC-02 -- Required if you install/operate a Class IV waste combustor at a hospital.
- WC-03 -- Required if you do not met the stack height requirements of Minn. R. 7011.1235.

If after reading through the following section, you determine that you are required to fill out one or more of the WC forms, contact the Air Quality Permit Document Coordinator.

6a) Are you proposing installing or modifying a waste combustor?

“Waste Combustor” means any emissions unit or emission facility where mixed municipal solid waste, solid waste, or refuse-derived fuel is combusted, and includes incinerators, energy recovery facilities, or other combustion devices. A metals recovery incinerator is a waste combustor. A combustion device combusting primarily wood, or at least 70 percent fossil fuel and wood in combination with up to 30 percent papermill wastewater treatment plant sludge is not a waste combustor. A soil treatment facility, paint burn-off oven, wood heater, or residential fireplace is not a waste combustor.

“Wood” is defined as: wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including sawdust, sander dust, wood chips, wood scraps, slabs, millings, shavings, and processed pellets made from wood and other forest residues.

A facility that is co-firing Refuse Derived Fuel (RDF) or Municipal Solid Waste (MSW) at rates less than 30 percent by weight is not regulated as a waste combustor, but is regulated as a boiler.

- ☐ Yes, I am installing or modifying a waste combustor. Answer questions 6b through 6e to determine whether you are allowed to continue to operate, and what type of permit the waste combustor requires. Allowed waste combustors must obtain an air emissions permit.
- ☒ No, the facility equipment is not subject to this rule. Done with this form.

6b) Is the waste combustor solely a crematory, pathological or an animal carcass incinerator?

- ☐ Yes. It is subject to standards of performance in Minn. R. 7011.1215, subp. 3. The waste combustor is an insignificant activity that does not need to be reported.
- ☐ No, the facility equipment is not subject to this rule.

6c) Is the design capacity of the waste combustor equal to or greater than 3 million Btu/hr?

“Design capacity” means: the hourly throughput of the waste combustor unit based on heat input from solid waste to the combustion system as stated by the manufacturer or designer, based on accepted design and engineering practices. For a non-continuous feed system, design capacity means the total heat input from solid waste per cycle. If you don’t have a manufacturer’s design capacity in terms of heat input, you may estimate heat input by the following formula:

$$H_{in} = (HHV) \times (R)$$

Where:

H_{in} = Heat input rate

HHV = heat value of waste

R = waste input rate, in lb/hr, as defined by the manufacturer

Commercial/Retail/Institutional Wastes = 7000 Btu/lb

General Industrial Wastes = 9000 Btu/lb

Medical/Infectious Wastes = 10,000 Btu/lb

- ☐ Yes, the waste combustor has a design capacity of 3 million Btu/hr or greater. The waste combustor is subject to the standards of performance applicable to waste combustors. There are also additional permit application requirements for this unit, as described in Minn. R. 7007.0501, or 7011.1210. Complete form WC-01.
- ☐ No, the heat input rate is below 3 million Btu/hr. Go to question 6d.

6d) Is the waste combustor used as a metal recover incinerator?



COMPLIANCE PLAN **CD-01**

Facility Name: Sanimax USA Inc

Permit Number: 03700070 - 006

Subject Item: **CE 001 Blood Process Venturi Scrubber**

Associated Items: **EU 002 Ring/Blood Dryer**

	NC/ CA	Type	Citation	Requirement
1.0		CD	hdr	OPERATIONAL REQUIREMENTS
2.0		LIMIT	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14	The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for Total Particulate Matter: greater than or equal to 90 percent control efficiency
3.0		LIMIT	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14	The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for PM < 10 micron: greater than or equal to 90 percent control efficiency
4.0		LIMIT	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14	The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for PM < 2.5 micron: less than or equal to 90 percent control efficiency
5.0		CD	hdr	MONITORING AND RECORDKEEPING REQUIREMENTS
6.0		LIMIT	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14; Minn. R. 7017.2025, subp. 3	Pressure Drop: greater than or equal to ~~4.0~~ inches of water column and less than or equal to ~~6.0~~ inches of water column across CE 001. 7.0 3.5
7.0		CD	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 4 and 5	The Permittee shall read and record the pressure drop and liquid flow rate across CE 001, once each day of operation.
8.0		LIMIT	Minn. 7007.0800, subp. 4(B)	Liquid Flow Rate: greater than or equal to 48 gallons/minute through CE 001.
9.0		CD	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 4 and 5	Recordkeeping of Pressure Drop and Liquid Flow Rate. The Permittee shall record the time and date of each pressure drop and liquid flow rate reading, whether or not any visible emissions were observed, and whether or not the observed pressure drop liquid flow rate were within the ranges specified in this permit.
10.0		CD	Minn. R. 7007.0800, subps. 4, 5 and 14	Corrective Actions: The Permittee shall take corrective action as soon as possible if any of the following occur: - visible emissions are observed; - the recorded pressure drop and/or liquid flow rate are outside the required operating ranges; or - CE 001 or any of its components are found during the inspections to need repair. Corrective actions shall return the pressure drop and/or liquid flow rate to within the permitted ranges and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the O & M Plan for the CE 001. The Permittee shall keep a record of the type and date of any corrective action taken for CE 001.
11.0		CD	Minn. R. 7007.0800, subps. 4, 5 and 14	Periodic Inspections: At least once per calendar quarter, or more frequently as required by the manufacturing specifications, the Permittee shall inspect the control equipment components. The Permittee shall maintain a written record of these inspections.



COMPLIANCE PLAN CD-01

Facility Name: Sanimax USA Inc

Permit Number: 03700070 - 006

Subject Item: CE 003 PRF Venturi Scrubber

Associated Items: EU 003 Protein Recovery Facility (PRF)

	NC/ CA	Type	Citation	Requirement
1.0		CD	hdr	OPERATIONAL REQUIREMENTS
2.0		LIMIT	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14	The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for Total Particulate Matter: greater than or equal to 90 percent control efficiency
3.0		LIMIT	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14	The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for PM < 10 micron: greater than or equal to 90 percent control efficiency
4.0		LIMIT	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14	The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for PM < 2.5 micron: greater than or equal to 90 percent control efficiency
5.0		CD	hdr	MONITORING AND RECORDKEEPING REQUIREMENTS
6.0		LIMIT	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14; Minn. R. 7017.2025, subp. 3	Pressure Drop: greater than or equal to ~~4.0~~ 7.0 inches of water column and less than or equal to ~~6.0~~ 3.5 inches of water column across CE 003.
7.0		CD	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 4 and 5	The Permittee shall read and record the pressure drop and liquid flow rate across CE 003, once each day of operation.
8.0		LIMIT	Minn. 7007.0800, subp. 4(B)	Liquid Flow Rate: greater than or equal to 16 gallons/minute through CE 003.
9.0		CD	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 4 and 5	Recordkeeping of Pressure Drop and Liquid Flow Rate. The Permittee shall record the time and date of each pressure drop and liquid flow rate reading, whether or not any visible emissions were observed, and whether or not the observed pressure drop liquid flow rate were within the ranges specified in this permit.
10.0		CD	Minn. R. 7007.0800, subps. 4, 5 and 14	Corrective Actions: The Permittee shall take corrective action as soon as possible if any of the following occur: - visible emissions are observed; - the recorded pressure drop and/or liquid flow rate are outside the required operating ranges; or - CE 003 or any of its components are found during the inspections to need repair. Corrective actions shall return the pressure drop and/or liquid flow rate to within the permitted ranges and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the O & M Plan for the CE 003. The Permittee shall keep a record of the type and date of any corrective action taken for CE 003.
11.0		CD	Minn. R. 7007.0800, subps. 4, 5 and 14	Periodic Inspections: At least once per calendar quarter, or more frequently as required by the manufacturing specifications, the Permittee shall inspect the control equipment components. The Permittee shall maintain a written record of these inspections.



COMPLIANCE PLAN CD-01

Facility Name: Sanimax USA Inc

Permit Number: 03700070 - 006

Subject Item: CE 012 Cookers Venturi Scrubber

Associated Items: EU 012 Continuous Cooker No. 1

EU 013 Continuous Cooker No. 2

GP 003 Continuous Cookers and Control Equipment

	NC/ CA	Type	Citation	Requirement
1.0		CD	hdr	OPERATIONAL REQUIREMENTS
2.0		LIMIT	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14	The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for Total Particulate Matter: greater than or equal to 90 percent control efficiency
3.0		LIMIT	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14	The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for PM < 10 micron: greater than or equal to 90 percent control efficiency
4.0		LIMIT	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14	The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for PM < 2.5 micron: greater than or equal to 90 percent control efficiency
5.0		CD	hdr	MONITORING AND RECORDKEEPING REQUIREMENTS
6.0		CD	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; To avoid classification as a major source under 40 CFR Section 70.2 and Minn. R. 7007.0200; Minn. R. 7007.0800, subps. 4 and 5	Visible Emissions: The Permittee shall check the Scrubber stack (SV 012) for any visible emissions once each day of operation during daylight hours. The Permittee shall read and record the pressure drop and liquid flow rate across CE 012, once each day of operation.
7.0		LIMIT	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; To avoid classification as a major source under 40 CFR Section 70.2 and Minn. R. 7007.0200; Minn. R. 7007.0800, subps. 4 and 5	Pressure Drop: greater than or equal to ~~4.0~~ inches of water column and less than or equal to ~~6.0~~ inches of water column across CE 012. 7.0 3.5
8.0		LIMIT	Minn. 7007.0800, subp. 4(B)	Liquid Flow Rate: greater than or equal to 65 gallons/minute through CE 012.
9.0		CD	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; To avoid classification as a major source under 40 CFR Section 70.2 and Minn. R. 7007.0200; Minn. R. 7007.0800, subps. 4 and 5	Recordkeeping of Visible Emissions, Pressure Drop and Liquid Flow Rate. The Permittee shall record the time and date of each pressure drop and liquid flow rate reading, whether or not any visible emissions were observed, and whether or not the observed pressure drop liquid flow rate were within the ranges specified in this permit.

TABLE A: LIMITS AND OTHER REQUIREMENTS

A-4 01/18/11

Facility Name: Sanimax USA Inc

Permit Number: 03700070 - 006

Subject Item: GP 001 Combustion Equipment ~~Subject to Facility-Wide SO2 Limit~~

Associated Items: EU 001 Boiler No. 1

EU 002 Ring/Blood Dryer

EU 023 Boiler No. 3

EU 006 Boiler No. 2

What to do	Why to do it
EMISSION LIMITS	hdr
Sulfur Dioxide: less than or equal to 240 tons/year using 12-month Rolling Sum as described below in Equation 1 to be calculated by the 15th day of each month for the previous 12-month period as described later in this permit.	Title I Condition: To avoid major source classification and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000
Equation 1: $SO_2 = [(EF_{ng} \times S\%_{ng} \times VOL_{ng}) + (EF_r \times S\%_r \times VOL_r) + (EF_d \times S\%_d \times VOL_d) + (EF_{rafvo} \times S\%_{rafvo} \times VOL_{rafvo}) + (EF_b \times S\%_b \times VOL_b) + (EF_p \times S\%_p \times VOL_p) + (EF_g \times S\%_g \times VOL_g)] / 2000$ Where, SO2 = annual sulfur dioxide emissions (tons per year) Natural Gas -- EF _{ng} = most recent US EPA-approved emission factor for SO2 emissions from natural gas combustion assuming all SO3 converts to SO2 (lb per gallon) S _r % = 12-month weighted average residual fuel oil sulfur content as certified by the supplier (percent by weight) VOL _r = volume of natural gas fired by the emission units in GP 001 using 12-month rolling sum (gallons per year)	Title I Condition: To avoid major source classification and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000
CONTINUED Residual Fuel Oil -- EF _r = most recent US EPA-approved emission factor for SO2 emissions from residual fuel oil combustion assuming all SO3 converts to SO2 (lb per gallon) S _r % = 12-month weighted average residual fuel oil sulfur content as certified by the supplier (percent by weight) VOL _r = volume of residual fuel oil fired by the emission units in GP 001 using 12-month rolling sum (gallons per year)	Title I Condition: To avoid major source classification and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000
CONTINUED Distillate Fuel Oil -- EF _d = most recent US EPA-approved emission factor for SO2 emissions from distillate fuel oil combustion assuming all SO3 converts to SO2 (lb per gallon) S _d % = 12-month weighted average distillate fuel oil sulfur content as certified by the supplier (percent by weight) VOL _d = volume of distillate fuel oil fired by the emission units in GP 001 using 12-month rolling sum (gallons per year)	Title I Condition: To avoid major source classification and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000
CONTINUED Refined Animal Fats and Vegetable Oils (RAFVO) -- EF _{rafvo} = most recent US EPA-approved emission factor for SO2 emissions based on distillate fuel oil combustion and assuming all SO3 converts to SO2 (lb per gallon) S _{rafvo} % = average RAFVO sulfur content as certified by laboratory analysis (percent by weight) VOL _{rafvo} = volume of RAFVO fired by the emission units in GP 001 using 12-month rolling sum (gallons per year) 2000 = conversion factor (lbs per ton)	Title I Condition: To avoid major source classification and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000
CONTINUED Biodiesel -- EF _b = most recent US EPA-approved emission factor for SO2 emissions based on distillate fuel oil combustion and assuming all SO3 converts to SO2 (lb per gallon) S _b % = average biodiesel sulfur content as certified by laboratory analysis (percent by weight) VOL _b = volume of biodiesel fired by the emission units in GP 001 using 12-month rolling sum (gallons per year) 2000 = conversion factor (lbs per ton)	Title I Condition: To avoid major source classification and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000

TABLE A: LIMITS AND OTHER REQUIREMENTS

A-5 01/18/11

Facility Name: Sanimax USA Inc

Permit Number: 03700070 - 006

CONTINUED Propane -- EFp = most recent US EPA-approved emission factor for SO2 emissions from propane combustion assuming all SO3 converts to SO2 (lb per gallon) S%p = 12 month weighted average propane sulfur content as certified by the supplier (percent by weight) VOLp = volume of propane fired by the emission units in GP 001 using 12-month rolling sum (gallons per year) 2000 = conversion factor (lbs per ton)	Title I Condition: To avoid major source classification and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000
CONTINUED Glycerin -- EFg = most recent US EPA-approved emission factor for SO2 emissions based on distillate fuel oil combustion and assuming all SO3 converts to SO2 (lb per gallon), until a testing factor is determined based on the testing requirements below S%g = average glycerin sulfur content as certified by laboratory analysis (percent by weight) VOLg = volume of glycerin fired by the emission units in GP 001 using 12-month rolling sum (gallons per year) 2000 = conversion factor (lbs per ton)	Title I Condition: To avoid major source classification and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000
RECORDKEEPING REQUIREMENTS	hdr
Daily Recordkeeping -- SO2 Emissions: The Permittee shall gather and record the following information: 1) Volume of residual fuel oil in gallons combusted in GP 001 for each day residual fuel oil is combusted in GP 001. 2) Volume of distillate fuel oil in gallons combusted in GP 001 for each day distillate fuel oil is combusted in GP 001. 3) Volume of refined animal fats and vegetable oils (RAFVO) in gallons combusted in GP 001 for each day RAFVO is combusted in GP 001. 4) Volume of biodiesel in gallons combusted in GP 001 for each day biodiesel is combusted in GP 001. 5) Volume of propane in gallons combusted in GP 001 for each day propane is combusted in GP 001. 6) Volume of glycerin in gallons combusted in GP 001 for each day glycerin is combusted in GP 001.	Title I Condition: To avoid major source classification and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000
Monthly Recordkeeping -- SO2 Emissions: By the 15th day of the month, the Permittee shall record and calculate the following: 1) Volume of residual fuel oil in gallons combusted in GP 001 during the previous month, calculated by summing the data collected for each day residual fuel oil was combusted in GP 001. 2) Volume of distillate fuel oil in gallons combusted in GP 001 during the previous month, calculated by summing the data collected for each day distillate fuel oil was combusted in GP 001. 3) Volume of RAFVO in gallons combusted in GP 001 during the previous month, calculated by summing the data collected for each day RAFVO was combusted in GP 001.	Minn. R. 7007.0800, subps. 4 and 5
CONTINUED 4) Volume of biodiesel in gallons combusted in GP 001 during the previous month, calculated by summing the data collected for each day biodiesel was combusted in GP 001. 5) Volume of propane in gallons combusted in GP 001 during the previous month, calculated by summing the data collected for each day propane was combusted in GP 001. 6) Volume of glycerin in gallons combusted in GP 001 during the previous month, calculated by summing the data collected for each day glycerin was combusted in GP 001. 7) SO2 emissions from residual fuel oil, distillate fuel oil, RAFVO, biodiesel, propane, and glycerin combustion from the previous 12 calendar months, calculated by using the data collected above from Items 1, 2, 3, 4, 5, 6, and 7 in Equation 1, and adding it the sum of the emissions data for the prior 11 months.	Minn. R. 7007.0800, subps. 4 and 5
Monthly Recordkeeping and Calculation- HAP Emissions: The Permittee shall maintain records and calculate the individual HAP and total HAP emissions on a monthly basis and 12-month rolling sum. Calculations shall be performed using MPCA approved emission factors as determined by performance test. HAPs recordkeeping and calculations shall performed after the initial glycerin and biodiesel testing are conducted.	Minn. R. 7007.0800, subps. 4 and 5
FUEL TESTING REQUIREMENTS	hdr

TABLE A: LIMITS AND OTHER REQUIREMENTS
A-6 01/18/11

Facility Name: Sanimax USA Inc

Permit Number: 03700070 - 006

Initial Performance Test for RAFVO Combustion: due within 30 days of commencing the burning of glycerin in EU 001, EU 002, or EU 006.

Initial Performance Test for Glycerin Combustion: due within 30 days of commencing the burning of glycerin in EU 001, EU 002, or EU 006.	Minn. R. 7017.2020, subp. 1
Initial Performance Test for Biodiesel Combustion: due within 30 days of commencing the burning of biodiesel in EU 001, EU 002, or EU 006.	Minn. R. 7017.2020, subp. 1
Fuel Testing Restrictions: Test burns shall be done in accordance with an MPCA-approved test plan and limited to no more than 14 days of operation and a test period not to exceed 90 days.	Minn. R. 7007.0800, subp. 2
Fuel Testing Requirements: Test burns shall be conducted for glycerin and biodiesel to measure emissions of PM, PM10, Opacity, CO, NOx, SO2, HCL, VOCs, HAPs and other chemicals of potential interest as determined by the MPCA for the purpose of developing emission factors.	Minn. R. 7007.0800, subp. 2 Test burns shall be conducted for RAFVO to measure emissions of PM2.5.
Fuel Testing Submittals: 30 days prior to testing glycerin or biodiesel, the Permittee shall submit a written performance test notification and test plan. The test plan shall: 1) meet the requirements of Minn. R. 7017.2030 2) include the type and estimated amount of fuels to be tested; operating parameters and anticipated fuel mixes during the test; air pollutants that will be measured during the testing; and a testing schedule, and ~~3) include an estimate of sulfur dioxide emissions based on analysis of the fuel for sulfur content.~~ , RAFVO,	Minn. R. 7017.2030, subp. 1-4; Minn. R. 7017.2018
Performance Test Notifications and Submittals; Performance Test Notification (written): due 30 days before each Performance Test Performance Test Plan: due 30 days before each Performance Test Performance Test Pre-Test Meeting: due 7 days before each Performance Test Performance Test Report: due 45 days after each Performance Test Performance Test Report - Microfiche Copy or CD: due 105 day after each Performance Test. The Notification, Test Plan, and Test Report may be submitted in alternate format as allowed by Minn. R. 7017.2018.	Minn. R. 7017.2030, subp. 1-4; Minn. R. 7017.2018 and Minn. R. 7017.2035, subp. 1-2
ALTERNATIVE COMPLIANCE , RAFVO,	hdr
Authorization to Burn Glycerin and/or Biodiesel Fuels Tested Below Existing Permit Limits: Within 45 days of completion of the fuel test, the Permittee shall submit a written test report to the MPCA that characterizes emissions from the tested fuel. Specifically the report will describe whether use of the fuel can be accomplished while the Permittee remains under existing permit limits for criteria and hazardous air pollutants. Upon written approval from the MPCA, and receipt of the appropriate permit amendment when necessary where there may be an increase in criteria pollutant emissions in pounds per hour, the Permittee may commence the use of the tested fuel. For any tested fuel where compliance with existing permit limits cannot be demonstrated during its use, the Permittee may not use such a fuel until it has complied with the permit amendment requirements in Minn. R. 7007.1150 through 7007.1500.	Minn. R. 7007.0800 subp. 2
CONTINUED If the tested fuel has emission factors higher than those specified but will not exceed 240.0 tpy of any individual criteria pollutant, 9.0 tpy of any HAP or 20.0 tons of total HAPs, upon written approval from the MPCA, and receipt of the appropriate permit amendment when necessary where there may be an increase in criteria pollutant emissions in pounds per hour, the Permittee may commence the use of the tested fuel using the tested emission factors as a limit.	Minn. R. 7007.0800, subp. 2
CONTINUED If the tested fuel has emission factors higher than those specified and will exceed 240.0 tpy of any individual criteria pollutant, 9.0 tpy of any HAP or 20.0 tons of total HAPs, or there may be a significant increase in criteria pollutant emissions in pounds per hour, the Permittee must obtain an appropriate permit amendment prior to commencing the use of the tested fuel.	Minn. R. 7007.0800, subp. 2

TABLE A: LIMITS AND OTHER REQUIREMENTS
A-15 01/18/11

Facility Name: Sanimax USA Inc

Permit Number: 03700070 - 006

Subject Item: EU 006 Boiler No. 2

Associated Items: GP 001 Combustion Equipment ~~Subject to Facility Wide SO2 Limit~~

SV 006 Boiler No. 2

What to do	Why to do it
EMISSION LIMITS	hdr
PM < 10 micron: less than or equal to 0.13 lbs/hour using 3-hour Average	Title I Condition: To avoid classification as major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. Stat. Section 116.07, subds. 4a & 9; Minn. R. 7007.0100, subp. 7(A), 7(L), & 7(M); Minn. R. 7007.0800, subps. 1, 2 & 4; Minn. R. 7009.0010-7009.0080
PM < 2.5 micron: less than or equal to ~~0.030~~ lbs/hour using 3-hour Average 0.13 lbs/hour (0.030 was incorrect because it did not account for worst-case fuel emissions)	Title I Condition: To avoid classification as major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. Stat. Section 116.07, subds. 4a & 9; Minn. R. 7007.0100, subp. 7(A), 7(L), & 7(M); Minn. R. 7007.0800, subps. 1, 2 & 4; Minn. R. 7009.0010-7009.0080
Total Particulate Matter: less than or equal to 0.40 lbs/million Btu heat input using 3-hour Rolling Average (maximum uncontrolled emissions from this unit are 0.014 lbs/million Btu heat input).	Minn. R. 7011.0515, subp. 1
Sulfur Dioxide: less than or equal to 2.0 lbs/million Btu heat input using 3-hour Rolling Average when burning distillate fuel oil.	Minn. R. 7011.0515, subp. 1
Opacity: less than or equal to 20 percent except for one six-minute period per hour of not more than 60 percent opacity.	Minn. R. 7011.0515, subp. 2
OTHER LIMITS AND REQUIREMENTS	hdr
Sulfur Content of Fuel: less than or equal to 0.50 percent by weight as certified by fuel supplier.	40 CFR Section 60.42c(d); 40 CFR Section 60.42c(d) and Minn. R. 7011.0515, subp. 1
Fuel usage: limited to natural gas, distillate oil, animal fat/vegetable oil, propane, biodiesel, and glycerin.	Minn. R. 7007.0800, subp. 4 and 5 "vegetable" (fix typo)
The SO2 emission limit applies at all times, including periods of startup, shutdown and malfunctions.	40 CFR Section 60.42c(r)
MONITORING, RECORDKEEPING and REPORTING REQUIREMENTS	hdr
Sulfur Content of Fuel: Obtain certification from fuel supplier to demonstrate compliance with SO2 limit. Certification from fuel supplier shall include name of the fuel supplier and a statement from the fuel supplier that the fuel oil complies with the specifications under the definition of distillate fuel oil in 40 CFR Section 60.41(c) and the sulfur content of the fuel oil following each fuel delivery.	40 CFR Section 60.44c(h)
Recordkeeping: By the last day of each calendar month, the Permittee shall record the amount of fuel combusted in EU 006 boiler during the previous calendar month. These records shall consist of purchase records, receipts, or fuel meter readings.	40 CFR Section 60.48c(g)
Recordkeeping: The Permittee shall maintain all records for a minimum of two years.	40 CFR Section 60.48c(i)
Reporting: The Permittee shall submit excess emissions reports quarterly if there are excess emissions by the 30th day of the third month following completion of the initial performance test, or semiannually if no excess emissions by the 30th day of the sixth month following completion of the initial performance test. Each subsequent quarterly or semiannual report shall be postmarked by the 30th day following the end of the reporting period.	40 CFR Sections 60.48c(c)
Reporting: The Permittee shall submit reports on fuel oil sulfur limits. Reports shall be postmarked by the 30th day following the end of each reporting period. Reports shall include records of fuel supplier certification, and certified statement that the records represent all fuel combusted. The fuel supplier certification must include the name of the fuel supplier, a statement from the fuel supplier that the fuel oil complies with the specifications under the definition of distillate fuel oil in 40 CFR Section 60.41c and the sulfur content of the fuel oil.	40 CFR Sections 60.48c(d), 60.48c(e)(11) and 60.48c(f) "supplier" (fix typo)
Notification: The Permittee shall provide 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, due no later than 60 days or as soon as practical before the change is commenced.	40 CFR Section 60.7(a)(4)
See GP 001 for additional Monitoring and Recordkeeping requirements for EU 006.	hdr

TABLE A: LIMITS AND OTHER REQUIREMENTS**A-12** 01/18/11

Facility Name: Sanimax USA Inc

Permit Number: 03700070 - 006

Subject Item: EU 002 Ring/Blood Dryer**Associated Items:** CE 001 Blood Process Venturi ScrubberGP 001 Combustion Equipment ~~Subject to Facility-Wide SO2 Limit~~

SV 002 Ring/Blood Dryer

What to do	Why to do it
EMISSION LIMITS	hdr
PM < 10 micron: less than or equal to 1.3 lbs/hour using 3-hour Average .	Title I Condition: To avoid classification as major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. Stat. Section 116.07, subds. 4a & 9; Minn. R. 7007.0100, subp. 7(A), 7(L), & 7(M); Minn. R. 7007.0800, subps. 1, 2 & 4; Minn. R. 7009.0010-7009.0080
PM < 2.5 micron: less than or equal to 0.74 lbs/hour using 3-hour Average 0.77 lbs/hour (new modeling inputs based on worst-case emissions)	Title I Condition: To avoid classification as major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. Stat. Section 116.07, subds. 4a & 9; Minn. R. 7007.0100, subp. 7(A), 7(L), & 7(M); Minn. R. 7007.0800, subps. 1, 2 & 4; Minn. R. 7009.0010-7009.0080
Total Particulate Matter: less than or equal to 0.30 grains/dry standard cubic foot using 3-hour Rolling Average of exhaust gas unless required to further reduce emissions to comply with the less stringent limit of either Minn. R. 7011.0730 or Minn. R. 7011. 0735.	Minn. R. 7011.0610, subp. 1(A)(1)
Sulfur Dioxide: less than or equal to 2.0 lbs/million Btu heat input using 3-hour Rolling Average when burning distillate fuel oil (maximum uncontrolled emissions from this unit are 0.51 lbs/million Btu heat input).	Minn. R. 7011.0610, subp. 2(A)(2)
Opacity: less than or equal to 20 percent except for one six-minute period per hour of not more than 60 percent opacity.	Minn. R. 7011.0610, subp. 1(A)(2)
Fuel usage: limited to natural gas, distillate oil, animal fat/vegetable oil, propane, biodiesel, and glycerin.	Minn. R. 7007.8000, subp. 4 and 5
OPERATIONAL REQUIREMENTS	"vegetable" (fix typo)
The Permittee shall vent emissions from EU 002 to CE 001 at all times EU 002 is in operation to meet applicable PM, PM10 and PM2.5 limits. The Permittee shall operate and maintain CE 001 at all times that any emission unit controlled by CE 001 is in operation.	Title I Condition: To avoid classification as major source and modification under 40 CFR Section 52.21 and Minn. 7007.3000; Minn. R. 7007.0800, subps. 4 and 5
MONITORING AND RECORDKEEPING REQUIREMENTS	hdr
See GP 001 for additional Monitoring and Recordkeeping requirements for EU 002.	hdr
See CE 001 for additional Monitoring and Recordkeeping requirements for CE 001.	hdr

TABLE A: LIMITS AND OTHER REQUIREMENTS

A-11 01/18/11

Facility Name: Sanimax USA Inc

Permit Number: 03700070 - 006

Subject Item: EU 001 Boiler No. 1**Associated Items:** GP 001 Combustion Equipment ~~Subject to Facility Wide SO2 Limit~~

SV 001 Boiler No. 1

What to do	Why to do it
EMISSION LIMITS	hdr
PM < 10 micron: less than or equal to ~~5.0 lbs/hour~~ using 3-hour Average 0.40 lbs/hour (new modeling inputs based on worst-case emissions)	Title I Condition: To avoid classification as major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. Stat. Section 116.07, subds. 4a & 9; Minn. R. 7007.0100, subp. 7(A), 7(L), & 7(M); Minn. R. 7007.0800, subps. 1, 2 & 4; Minn. R. 7009.0010-7009.0080
PM < 2.5 micron: less than or equal to ~~3.3 lbs/hour~~ using 3-hour Average 0.39 lbs/hour (new modeling inputs based on worst-case emissions)	Title I Condition: To avoid classification as major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. Stat. Section 116.07, subds. 4a & 9; Minn. R. 7007.0100, subp. 7(A), 7(L), & 7(M); Minn. R. 7007.0800, subps. 1, 2 & 4; Minn. R. 7009.0010-7009.0080
Total Particulate Matter: less than or equal to 0.40 lbs/million Btu heat input using 3-hour Rolling Average (maximum uncontrolled emissions from this unit are 0.11 lbs/million Btu heat input).	Minn. R. 7011.0515, subp. 1
Sulfur Dioxide: less than or equal to 2.0 lbs/million Btu heat input using 3-hour Rolling Average when burning residual fuel oil or refined animal fats & vegetable oils (maximum uncontrolled emissions from this unit are 1.59 lbs/million Btu heat input).	Minn. R. 7011.0515, subp. 1
Opacity: less than or equal to 20 percent except for one six-minute period per hour of not more than 60 percent opacity.	Minn. R. 7011.0515, subp. 2
Fuel usage: limited to natural gas, ~~residual oil~~ , distillate oil, animal fat/vegetable oil, propane, biodiesel, and glycerin.	Minn. R. 7007.0800, subps. 4 and 5
MONITORING AND RECORDKEEPING REQUIREMENTS	"vegetable" (fix typo)
See GP 001 for additional Monitoring and Recordkeeping requirements for EU 001.	hdr

TABLE A: LIMITS AND OTHER REQUIREMENTS

A-26

01/18/11

Facility Name: Sanimax USA Inc

Permit Number: 03700070 - 006

Subject Item: CE 012 Cookers Venturi Scrubber**Associated Items:** EU 012 Continuous Cooker No. 1

EU 013 Continuous Cooker No. 2

GP 003 Continuous Cookers and Control Equipment

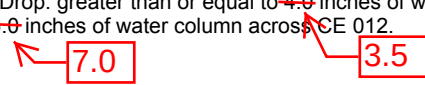
What to do	Why to do it
OPERATIONAL REQUIREMENTS	hdr
The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for Total Particulate Matter: greater than or equal to 90 percent control efficiency	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14
The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for PM < 10 micron: greater than or equal to 90 percent control efficiency	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14
The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for PM < 2.5 micron: greater than or equal to 90 percent control efficiency	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14
MONITORING AND RECORDKEEPING REQUIREMENTS	hdr
Visible Emissions: The Permittee shall check the Scrubber stack (SV 012) for any visible emissions once each day of operation during daylight hours. The Permittee shall read and record the pressure drop and liquid flow rate across CE 012, once each day of operation.	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; To avoid classification as a major source under 40 CFR Section 70.2 and Minn. R. 7007.0200; Minn. R. 7007.0800, subps. 4 and 5
Pressure Drop: greater than or equal to ~~4.0~~ inches of water column and less than or equal to ~~6.0~~ inches of water column across CE 012. 	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; To avoid classification as a major source under 40 CFR Section 70.2 and Minn. R. 7007.0200; Minn. R. 7007.0800, subps. 4 and 5
Liquid Flow Rate: greater than or equal to 65 gallons/minute through CE 012.	Minn. 7007.0800, subp. 4(B)
Recordkeeping of Visible Emissions, Pressure Drop and Liquid Flow Rate. The Permittee shall record the time and date of each pressure drop and liquid flow rate reading, whether or not any visible emissions were observed, and whether or not the observed pressure drop liquid flow rate were within the ranges specified in this permit.	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; To avoid classification as a major source under 40 CFR Section 70.2 and Minn. R. 7007.0200; Minn. R. 7007.0800, subps. 4 and 5
Corrective Actions: The Permittee shall take corrective action as soon as possible if any of the following occur: - visible emissions are observed; - the recorded pressure drop and/or liquid flow rate are outside the required operating ranges; or - CE 012 or any of its components are found during the inspections to need repair. Corrective actions shall return the pressure drop and/or liquid flow rate to within the permitted ranges and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the O & M Plan for the CE 012. The Permittee shall keep a record of the type and date of any corrective action taken for CE 012.	Minn. R. 7007.0800, subps. 4, 5 and 14
Periodic Inspections: At least once per calendar quarter, or more frequently as required by the manufacturing specifications, the Permittee shall inspect the control equipment components. The Permittee shall maintain a written record of these inspections.	Minn. R. 7007.0800, subps. 4, 5 and 14

TABLE A: LIMITS AND OTHER REQUIREMENTS**A-24**

01/18/11

Facility Name: Sanimax USA Inc

Permit Number: 03700070 - 006

Subject Item: CE 003 PRF Venturi Scrubber**Associated Items:** EU 003 Protein Recovery Facility (PRF)

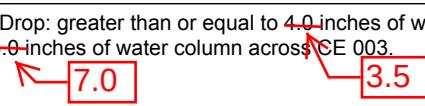
What to do	Why to do it
OPERATIONAL REQUIREMENTS	hdr
The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for Total Particulate Matter: greater than or equal to 90 percent control efficiency	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14
The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for PM < 10 micron: greater than or equal to 90 percent control efficiency	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14
The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for PM < 2.5 micron: greater than or equal to 90 percent control efficiency	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14
MONITORING AND RECORDKEEPING REQUIREMENTS	hdr
Pressure Drop: greater than or equal to ~~4.0~~ inches of water column and less than or equal to ~~6.0~~ inches of water column across CE 003. 	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14; Minn. R. 7017.2025, subp. 3
The Permittee shall read and record the pressure drop and liquid flow rate across CE 003, once each day of operation.	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 4 and 5
Liquid Flow Rate: greater than or equal to 16 gallons/minute through CE 003.	Minn. 7007.0800, subp. 4(B)
Recordkeeping of Pressure Drop and Liquid Flow Rate. The Permittee shall record the time and date of each pressure drop and liquid flow rate reading, whether or not any visible emissions were observed, and whether or not the observed pressure drop liquid flow rate were within the ranges specified in this permit.	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 4 and 5
Corrective Actions: The Permittee shall take corrective action as soon as possible if any of the following occur: - visible emissions are observed; - the recorded pressure drop and/or liquid flow rate are outside the required operating ranges; or - CE 003 or any of its components are found during the inspections to need repair. Corrective actions shall return the pressure drop and/or liquid flow rate to within the permitted ranges and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the O & M Plan for the CE 003. The Permittee shall keep a record of the type and date of any corrective action taken for CE 003.	Minn. R. 7007.0800, subps. 4, 5 and 14
Periodic Inspections: At least once per calendar quarter, or more frequently as required by the manufacturing specifications, the Permittee shall inspect the control equipment components. The Permittee shall maintain a written record of these inspections.	Minn. R. 7007.0800, subps. 4, 5 and 14

TABLE A: LIMITS AND OTHER REQUIREMENTS

A-23

01/18/11

Facility Name: Sanimax USA Inc

Permit Number: 03700070 - 006

Subject Item: CE 001 Blood Process Venturi Scrubber**Associated Items:** EU 002 Ring/Blood Dryer

What to do	Why to do it
OPERATIONAL REQUIREMENTS	hdr
The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for Total Particulate Matter: greater than or equal to 90 percent control efficiency	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14
The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for PM < 10 micron: greater than or equal to 90 percent control efficiency	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14
The Permittee shall operate and maintain the control equipment such that it achieves an overall control efficiency for PM < 2.5 micron: less than or equal to 90 percent control efficiency	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14
MONITORING AND RECORDKEEPING REQUIREMENTS	"greater than or equal to" (fix typo)
Pressure Drop: greater than or equal to ~~4.0~~ inches of water column and less than or equal to ~~6.0~~ inches of water column across CE 001.	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 2 and 14; Minn. R. 7017.2025, subp. 3
The Permittee shall read and record the pressure drop and liquid flow rate across CE 001, once each day of operation.	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 4 and 5
Liquid Flow Rate: greater than or equal to 48 gallons/minute through CE 001.	Minn. 7007.0800, subp. 4(B)
Recordkeeping of Pressure Drop and Liquid Flow Rate. The Permittee shall record the time and date of each pressure drop and liquid flow rate reading, whether or not any visible emissions were observed, and whether or not the observed pressure drop liquid flow rate were within the ranges specified in this permit.	Title I Condition: To avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000; Minn. R. 7007.0800, subps. 4 and 5
Corrective Actions: The Permittee shall take corrective action as soon as possible if any of the following occur: - visible emissions are observed; - the recorded pressure drop and/or liquid flow rate are outside the required operating ranges; or - CE 001 or any of its components are found during the inspections to need repair. Corrective actions shall return the pressure drop and/or liquid flow rate to within the permitted ranges and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the O & M Plan for the CE 001. The Permittee shall keep a record of the type and date of any corrective action taken for CE 001.	Minn. R. 7007.0800, subps. 4, 5 and 14
Periodic Inspections: At least once per calendar quarter, or more frequently as required by the manufacturing specifications, the Permittee shall inspect the control equipment components. The Permittee shall maintain a written record of these inspections.	Minn. R. 7007.0800, subps. 4, 5 and 14



Minnesota Pollution Control Agency

520 Lafayette Road North
St. Paul, MN 55155-4194

GI-07

Facility Emissions Summary Air Quality Permit Program

Doc Type: Permit Application

Instructions on Page 2

1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:				CAS#:				CAS#:			
Emission	Emission	3d) Pollutant Name:	PM			Pollutant Name:	PM10			Pollutant Name:	PM2.5		
Source Type	Source ID No.	3e) Potential			3f) Actual	Potential			Actual	Potential			Actual
		Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr
EU	001	0.80	3.51	3.51		0.40	1.75	1.75		0.39	1.71	1.71	
EU	002	1.43	6.28	6.28		1.26	5.52	5.52		0.77	3.36	3.36	
EU	006	0.28	1.21	1.21		0.14	0.60	0.60		0.13	0.59	0.59	
EU	023	0.53	2.32	2.32		0.28	1.24	1.24		0.28	1.24	1.24	

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total	Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year	
Facility	13.31	13.31			9.11	9.11			6.90	6.90		

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Facility Emissions Summary Air Quality Permit Program

Doc Type: Permit Application

Instructions on Page 2

1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:				CAS#:				CAS#:			
Emission	Emission	3d) Pollutant Name:		SO2		Pollutant Name:		NOx		Pollutant Name:		CO	
Source Type	Source ID No.	3e) Potential			3f) Actual	Potential			Actual	Potential			Actual
		Lbs per Hr	Unrestricted tpy	Limited tpy		Lbs per Hr	Unrestricted tpy	Limited tpy		Lbs per Hr	Unrestricted tpy	Limited tpy	
EU	001	5.69	24.91	24.91		8.01	35.09	35.09		4.20	18.40	18.40	
EU	002	0.56	2.44	2.44		0.79	3.44	3.44		0.41	1.80	1.80	
EU	006	1.96	8.59	8.59		2.76	12.09	12.09		1.45	6.34	6.34	
EU	023	0.61	2.66	2.66		5.29	23.15	23.15		3.05	13.35	13.35	

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total	Unrestricted			Tons/year	Unrestricted			Tons/year	Unrestricted			Tons/year
Facility	38.60			38.60	73.77			73.77	39.89			39.89

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Facility Emissions Summary Air Quality Permit Program

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Instructions on Page 2

1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:				CAS#:				CAS#:			
Emission	Emission	3d) Pollutant Name:		VOC		Pollutant Name:		CO2		Pollutant Name:		CH4	
Source Type	Source ID No.	3e) Potential			3f) Actual	Potential			Actual	Potential			Actual
		Lbs per Hr	Unrestricted tpy	Limited tpy		Lbs per Hr	Unrestricted tpy	Limited tpy		Lbs per Hr	Unrestricted tpy	Limited tpy	
EU	001	0.45	1.95	1.95		8,932	39,121	39,121		0.12	0.50	0.50	
EU	002	0.24	1.07	1.07		876	3,835	3,835		0.01	0.05	0.05	
EU	006	0.15	0.67	0.67		3,079	13,485	13,485		0.12	0.50	0.50	
EU	023	0.32	1.42	1.42		5,893	25,813	25,813		0.08	0.37	0.37	

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year
Facility		5.11	5.11			82,254	82,254			1.42	1.42	

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Facility Emissions Summary Air Quality Permit Program

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Instructions on Page 2

1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:				CAS#:				CAS#:			
Emission	Emission	3d) Pollutant Name:		N2O		Pollutant Name:		CO2e		Pollutant Name:		Total HAPs	
Source Type	Source ID No.	3e) Potential			3f) Actual	Potential			Actual	Potential			Actual
		Lbs per Hr	Unrestricted tpy	Limited tpy		Lbs per Hr	Unrestricted tpy	Limited tpy		Lbs per Hr	Unrestricted tpy	Limited tpy	
EU	001	0.50	2.20	2.20		8,964	39,264	39,264		0.09	0.41	0.41	
EU	002	0.05	0.22	0.22		879	3,849	3,849		0.01	0.04	0.04	
EU	006	0.17	0.76	0.76		3,090	13,535	13,535		0.03	0.14	0.14	
EU	023	0.36	1.59	1.59		5,915	25,907	25,907		0.07	0.30	0.30	

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total	Unrestricted Limited Tons/year				Unrestricted Limited Tons/year				Unrestricted Limited Tons/year			
Facility	4.76 4.76				83,761 83,761				0.90 0.90			

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**Facility Emissions Summary
Air Quality Permit Program**

Doc Type: Permit Application

Instructions on Page 2

1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:		83-32-9		CAS#:		203-96-8		CAS#:		120-12-7	
Emission	Emission	3d) Pollutant Name:		Acenaphthene		Pollutant Name:		Acenaphthylene		Pollutant Name:		Anthracene	
Source Type	Source ID No.	3e) Potential			3f) Actual	Potential			Actual	Potential			Actual
		Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr
EU	001	8.45E-06	3.70E-05	3.70E-05		1.01E-07	4.44E-07	4.44E-07		4.89E-07	2.14E-06	2.14E-06	
EU	002	8.29E-07	3.63E-06	3.63E-06		9.93E-09	4.35E-08	4.35E-08		4.79E-08	2.10E-07	2.10E-07	
EU	006	2.91E-06	1.28E-05	1.28E-05		3.49E-08	1.53E-07	1.53E-07		1.68E-07	7.38E-07	7.38E-07	
EU	023	5.58E-06	2.44E-05	2.44E-05		6.69E-08	2.93E-07	2.93E-07		3.22E-07	1.41E-06	1.41E-06	

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year
Facility		7.78E-05	7.78E-05			9.33E-07	9.33E-07			4.50E-06	4.50E-06	

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**Facility Emissions Summary
Air Quality Permit Program**

Doc Type: Permit Application

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1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:	56-55-3			CAS#:	71-43-2			CAS#:	50-32-8		
Emission	Emission	3d) Pollutant Name:	Benz(a)anthracene			Pollutant Name:	Benzene			Pollutant Name:	Benzo(a)pyrene		
Source Type	Source ID No.	3e) Potential			3f) Actual	Potential			Actual	Potential			Actual
		Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr
EU	001	1.61E-06	7.03E-06	7.03E-06		1.05E-04	4.60E-04	4.60E-04		6.00E-08	2.63E-07	2.63E-07	
EU	002	1.57E-07	6.90E-07	6.90E-07		1.03E-05	4.51E-05	4.51E-05		5.88E-09	2.58E-08	2.58E-08	
EU	006	5.54E-07	2.42E-06	2.42E-06		3.62E-05	1.59E-04	1.59E-04		2.07E-08	9.06E-08	9.06E-08	
EU	023	1.06E-06	4.64E-06	4.64E-06		7.62E-05	3.34E-04	3.34E-04		4.35E-08	1.91E-07	1.91E-07	

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total	Unrestricted			Tons/year	Unrestricted			Tons/year	Unrestricted			Tons/year
Facility	1.48E-05				9.97E-04				5.70E-07			

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**Facility Emissions Summary
Air Quality Permit Program**

Doc Type: Permit Application

Instructions on Page 2

1a) AQ Facility ID No.: 03700070

1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:	205-99-2			CAS#:	191-24-2			CAS#:	205-82-3		
Emission	Emission	3d) Pollutant Name:	Benzo(b)fluoranthene			Pollutant Name:	Benzo(g,h,i)perylene			Pollutant Name:	Benzo(k)fluoranthene		
Source Type	Source ID No.	3e) Potential			3f) Actual	Potential			Actual	Potential			Actual
		Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr
EU	001	5.93E-07	2.60E-06	2.60E-06		9.05E-07	3.96E-06	3.96E-06		5.93E-07	2.60E-06	2.60E-06	
EU	002	5.81E-08	2.55E-07	2.55E-07		8.87E-08	3.89E-07	3.89E-07		5.81E-08	2.55E-07	2.55E-07	
EU	006	2.04E-07	8.95E-07	8.95E-07		3.12E-07	1.37E-06	1.37E-06		2.04E-07	8.95E-07	8.95E-07	
EU	023	3.91E-07	1.71E-06	1.71E-06		5.97E-07	2.62E-06	2.62E-06		3.91E-07	1.71E-06	1.71E-06	

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year
Facility		5.46E-06	5.46E-06			8.34E-06	8.34E-06			5.46E-06	5.46E-06	

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**Facility Emissions Summary
Air Quality Permit Program**

Doc Type: Permit Application

Instructions on Page 2

1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:	218-01-9			CAS#:	53-70-3			CAS#:	106-46-7		
Emission	Emission	3d) Pollutant Name:	Chrysene			Pollutant Name:	Dibenzo(a,h)anthracene			Pollutant Name:	Dichlorobenzene		
Source Type	Source ID No.	3e) Potential			3f) Actual	Potential			Actual	Potential			Actual
		Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr
EU	001	9.53E-07	4.18E-06	4.18E-06		6.00E-05	2.63E-04	2.63E-04		6.00E-05	2.63E-04	2.63E-04	
EU	002	9.35E-08	4.09E-07	4.09E-07		5.88E-06	2.58E-05	2.58E-05		5.88E-06	2.58E-05	2.58E-05	
EU	006	3.29E-07	1.44E-06	1.44E-06		2.07E-05	9.06E-05	9.06E-05		2.07E-05	9.06E-05	9.06E-05	
EU	023	6.29E-07	2.75E-06	2.75E-06		4.35E-05	1.91E-04	1.91E-04		4.35E-05	1.91E-04	1.91E-04	

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year
Facility		8.78E-06	8.78E-06			5.70E-04	5.70E-04			5.70E-04	5.70E-04	

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**Facility Emissions Summary
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Instructions on Page 2

1a) AQ Facility ID No.: 03700070

1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:		57-97-6		CAS#:		100-41-4		CAS#:		206-44-0	
Emission	Emission	3d) Pollutant Name:		7,12-Dimethyl-benz(a)anthracene		Pollutant Name:		Ethylbenzene		Pollutant Name:		Fluoranthene	
Source Type	Source ID No.	3e) Potential			3f) Actual	Potential			Actual	Potential			Actual
		Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr
EU	001	8.00E-07	3.50E-06	3.50E-06		2.55E-05	1.12E-04	1.12E-04		1.94E-06	8.49E-06	8.49E-06	
EU	002	7.84E-08	3.44E-07	3.44E-07		2.50E-06	1.09E-05	1.09E-05		1.90E-07	8.32E-07	8.32E-07	
EU	006	2.76E-07	1.21E-06	1.21E-06		8.78E-06	3.85E-05	3.85E-05		6.68E-07	2.93E-06	2.93E-06	
EU	023	5.80E-07	2.54E-06	2.54E-06		1.68E-05	7.36E-05	7.36E-05		1.28E-06	5.60E-06	5.60E-06	

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year
Facility		7.60E-06	7.60E-06			2.35E-04	2.35E-04			1.79E-05	1.79E-05	

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**Facility Emissions Summary
Air Quality Permit Program**

Doc Type: Permit Application

Instructions on Page 2

1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:	86-73-7			CAS#:	50-00-0			CAS#:	110-54-3		
Emission	Emission	3d) Pollutant Name:	Fluorene			Pollutant Name:	Formaldehyde			Pollutant Name:	Hexane		
Source Type	Source ID No.	3e) Potential			3f) Actual	Potential			Actual	Potential			Actual
		Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr
EU	001	1.79E-06	7.84E-06	7.84E-06		1.32E-02	5.79E-02	5.79E-02		9.00E-02	3.94E-01	3.94E-01	
EU	002	1.76E-07	7.69E-07	7.69E-07		1.30E-03	5.68E-03	5.68E-03		8.82E-03	3.86E-02	3.86E-02	
EU	006	6.17E-07	2.70E-06	2.70E-06		4.56E-03	2.00E-02	2.00E-02		3.10E-02	1.36E-01	1.36E-01	
EU	023	1.18E-06	5.17E-06	5.17E-06		8.72E-03	3.82E-02	3.82E-02		6.53E-02	2.86E-01	2.86E-01	

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year
Facility		1.65E-05	1.65E-05			1.22E-01	1.22E-01			8.55E-01	8.55E-01	

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**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

GI-07

**Facility Emissions Summary
Air Quality Permit Program**

Doc Type: Permit Application

Instructions on Page 2

1a) AQ Facility ID No.: 03700070

1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:		193-39-5		CAS#:		91-57-6		CAS#:		56-49-5	
Emission	Emission	3d) Pollutant Name:		Indendo(1,2,3-cd)pyrene		Pollutant Name:		2-Methylnaphthalene		Pollutant Name:		3-Methylchloranthrene	
Source Type	Source ID No.	3e) Potential			3f) Actual	Potential			Actual	Potential			Actual
		Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr
EU	001	8.57E-07	3.75E-06	3.75E-06		1.20E-06	5.26E-06	5.26E-06		9.00E-08	3.94E-07	3.94E-07	
EU	002	8.40E-08	3.68E-07	3.68E-07		1.18E-07	5.15E-07	5.15E-07		8.82E-09	3.86E-08	3.86E-08	
EU	006	2.95E-07	1.29E-06	1.29E-06		4.14E-07	1.81E-06	1.81E-06		3.10E-08	1.36E-07	1.36E-07	
EU	023	5.66E-07	2.48E-06	2.48E-06		8.71E-07	3.81E-06	3.81E-06		6.53E-08	2.86E-07	2.86E-07	

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year
Facility		7.89E-06	7.89E-06			1.14E-05	1.14E-05			8.55E-07	8.55E-07	

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**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

GI-07

**Facility Emissions Summary
Air Quality Permit Program**

Doc Type: Permit Application

Instructions on Page 2

1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:		91-20-3		CAS#:		85-01-8		CAS#:		129-00-0	
Emission	Emission	3d) Pollutant Name:		Naphthalene		Pollutant Name:		Phenanthrene		Pollutant Name:		Pyrene	
Source Type	Source ID No.	3e) Potential			3f) Actual	Potential			Actual	Potential			Actual
		Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr
EU	001	4.53E-04	1.98E-03	1.98E-03		4.21E-06	1.84E-05	1.84E-05		1.70E-06	7.46E-06	7.46E-06	
EU	002	4.44E-05	1.94E-04	1.94E-04		4.12E-07	1.81E-06	1.81E-06		1.67E-07	7.31E-07	7.31E-07	
EU	006	1.56E-04	6.83E-04	6.83E-04		1.45E-06	6.35E-06	6.35E-06		5.87E-07	2.57E-06	2.57E-06	
EU	023	2.99E-04	1.31E-03	1.31E-03		2.77E-06	1.22E-05	1.22E-05		1.12E-06	4.92E-06	4.92E-06	

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year
Facility		4.17E-03	4.17E-03			3.87E-05	3.87E-05			1.57E-05	1.57E-05	

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**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

GI-07

**Facility Emissions Summary
Air Quality Permit Program**

Doc Type: Permit Application

Instructions on Page 2

1a) AQ Facility ID No.: 03700070 1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:	108-88-3			CAS#:	71-55-6			CAS#:	1330-20-7		
Emission	Emission	3d) Pollutant Name:	Toluene			Pollutant Name:	1,1,1-Trichloroethane			Pollutant Name:	Xylenes		
Source Type	Source ID No.	3e) Potential			3f) Actual	Potential			Actual	Potential			Actual
		Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr
EU	001	2.48E-03	1.09E-02	1.09E-02		9.45E-05	4.14E-04	4.14E-04		4.37E-05	1.91E-04	1.91E-04	
EU	002	2.43E-04	1.07E-03	1.07E-03		9.27E-06	4.06E-05	4.06E-05		4.28E-06	1.87E-05	1.87E-05	
EU	006	8.56E-04	3.75E-03	3.75E-03		3.26E-05	1.43E-04	1.43E-04		1.50E-05	6.59E-05	6.59E-05	
EU	023	1.64E-03	7.18E-03	7.18E-03		6.24E-05	2.73E-04	2.73E-04		2.88E-05	1.26E-04	1.26E-04	

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year
Facility		2.29E-02	2.29E-02			8.70E-04	8.70E-04			4.02E-04	4.02E-04	

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**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

GI-07

**Facility Emissions Summary
Air Quality Permit Program**

Doc Type: Permit Application

Instructions on Page 2

1a) AQ Facility ID No.: 03700070

1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:		7440-36-0		CAS#:		7440-38-2		CAS#:		7440-41-7	
Emission	Emission	3d) Pollutant Name:		Antimony compounds		Pollutant Name:		Arsenic compounds		Pollutant Name:		Beryllium compounds	
Source Type	Source ID No.	3e) Potential			3f) Actual	Potential			Actual	Potential			Actual
		Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr
EU	001	2.63E-04	1.15E-03	1.15E-03		1.00E-05	4.38E-05	4.38E-05		6.00E-07	2.63E-06	2.63E-06	
EU	002	2.57E-05	1.13E-04	1.13E-04		9.80E-07	4.29E-06	4.29E-06		5.88E-08	2.58E-07	2.58E-07	
EU	006	9.05E-05	3.96E-04	3.96E-04		3.45E-06	1.51E-05	1.51E-05		2.07E-07	9.06E-07	9.06E-07	
EU	023	1.90E-04	8.34E-04	8.34E-04		7.25E-06	3.18E-05	3.18E-05		4.35E-07	1.91E-06	1.91E-06	

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year
Facility		2.49E-03	2.49E-03			9.50E-05	9.50E-05			5.70E-06	5.70E-06	

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Minnesota Pollution Control Agency

520 Lafayette Road North
St. Paul, MN 55155-4194

GI-07

Facility Emissions Summary Air Quality Permit Program

Doc Type: Permit Application

Instructions on Page 2

1a) AQ Facility ID No.: 03700070

1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:		7440-43-9		CAS#:		7440-47-3		CAS#:		7440-48-4	
Emission	Emission	3d) Pollutant Name:		Cadmium compounds		Pollutant Name:		Chromium compounds		Pollutant Name:		Cobalt compounds	
Source Type	Source ID No.	3e) Potential			3f) Actual	Potential			Actual	Potential			Actual
		Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr
EU	001	5.50E-05	2.41E-04	2.41E-04		7.00E-05	3.07E-04	3.07E-04		4.20E-06	1.84E-05	1.84E-05	
EU	002	5.39E-06	2.36E-05	2.36E-05		6.86E-06	3.01E-05	3.01E-05		4.12E-07	1.80E-06	1.80E-06	
EU	006	1.90E-05	8.30E-05	8.30E-05		2.41E-05	1.06E-04	1.06E-04		1.45E-06	6.34E-06	6.34E-06	
EU	023	3.99E-05	1.75E-04	1.75E-04		5.08E-05	2.22E-04	2.22E-04		3.05E-06	1.33E-05	1.33E-05	

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year
Facility		5.22E-04	5.22E-04			6.65E-04	6.65E-04			3.99E-05	3.99E-05	

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**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

GI-07

**Facility Emissions Summary
Air Quality Permit Program**

Doc Type: Permit Application

Instructions on Page 2

1a) AQ Facility ID No.: 03700070

1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:	7439-96-5			CAS#:	7439-97-6			CAS#:	7440-02-0		
Emission	Emission	3d) Pollutant Name:	Manganese compounds			Pollutant Name:	Mercury compounds			Pollutant Name:	Nickel compounds		
Source Type	Source ID No.	3e) Potential			3f) Actual	Potential			Actual	Potential			Actual
		Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr
EU	001	1.90E-05	8.32E-05	8.32E-05		1.30E-05	5.69E-05	5.69E-05		1.05E-04	4.60E-04	4.60E-04	
EU	002	1.86E-06	8.16E-06	8.16E-06		1.27E-06	5.58E-06	5.58E-06		1.03E-05	4.51E-05	4.51E-05	
EU	006	6.55E-06	2.87E-05	2.87E-05		4.48E-06	1.96E-05	1.96E-05		3.62E-05	1.59E-04	1.59E-04	
EU	023	1.38E-05	6.04E-05	6.04E-05		9.43E-06	4.13E-05	4.13E-05		7.62E-05	3.34E-04	3.34E-04	

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year
Facility		1.80E-04	1.80E-04			1.23E-04	1.23E-04			9.97E-04	9.97E-04	

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**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

GI-07

**Facility Emissions Summary
Air Quality Permit Program**

Doc Type: Permit Application

Instructions on Page 2

1a) AQ Facility ID No.: 03700070

1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a)	3b)	3c) CAS#:			7782-49-2	CAS#:				CAS#:			
Emission	Emission	3d) Pollutant Name:			Selenium compounds	Pollutant Name:				Pollutant Name:			
Source Type	Source ID No.	3e)			3f) Actual	Potential			Actual	Potential			Actual
		Potential											
		Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr	Lbs per Hr	Unrestricted tpy	Limited tpy	Tons per yr
EU	001	1.20E-06	5.26E-06	5.26E-06									
EU	002	1.18E-07	5.15E-07	5.15E-07									
EU	006	4.14E-07	1.81E-06	1.81E-06									
EU	023	8.71E-07	3.81E-06	3.81E-06									

4)	Potential			Actual	Potential			Actual	Potential			Actual
Total		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year		Unrestricted	Limited	Tons/year
Facility		1.14E-05	1.14E-05									

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Minnesota Pollution Control Agency

520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

AIR QUALITY FORM **HG-01** **MERCURY RELEASES TO AMBIENT AIR**

October 25, 2006

1a) AQ Facility ID No.: 03700070

1b) AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3) Use this table to summarize changes in mercury emissions associated with a new or expanded facility or a changed or modified operation at an existing facility.

3a) Emission Unit (EU) ID number	3b) potential to emit after the change (pounds per year)				3c) current actual emissions (pounds per year)				3d) future estimated actual emissions (pounds per year)			
	particulate- bound (Hg-p)	reactive gaseous (HgII)	Elemental (Hg0)	Total (HgT)	particulate- bound (Hg-p)	reactive gaseous (HgII)	Elemental (Hg0)	Total (HgT)	particulate- bound (Hg-p)	reactive gaseous (HgII)	Elemental (Hg0)	Total (HgT)
Total facility				0.336				<0.336				<0.0392

4) Calculation Data.

4a) Where are the calculations summarized in item 3? Please list where in the permit application (section and/or pages) we can find mercury emission calculations for each of the emission units listed in item 3.

SEE Combustion emissions tab on Application CD

4b) What is the source of the data used to determine the mercury emissions in item 3 (e.g., published emission factors, site specific test data, mass balance, etc.) ?

AP-42

See GI-02 for diagram attached for item 5)

5) Attach a diagram that shows the flow of mercury through the facility. See the example in the instructions.

☒ Attached

6) Use this table to summarize available alternative methods to reduce mercury emissions from the facility. Complete a separate table for each emission unit.

EU _____

6a) Description	6b) Total Mercury Emitted (lb/yr)	6c) Reduction Potential (lb/yr)	6d) Annualized Cost (\$)	6e) Cost Effectiveness (\$ per lb Hg)
☐ Baseline/Uncontrolled emissions				
☐				
☐				
☐				

EU _____

6a) Description	6b) Total Mercury Emitted (lb/yr)	6c) Reduction Potential (lb/yr)	6d) Annualized Cost (\$)	6e) Cost Effectiveness (\$ per lb Hg)
☐ Baseline/Uncontrolled emissions				
☐				
☐				
☐				

EU _____

6a) Description	6b) Total Mercury Emitted (lb/yr)	6c) Reduction Potential (lb/yr)	6d) Annualized Cost (\$)	6e) Cost Effectiveness (\$ per lb Hg)
☐ Baseline/Uncontrolled emissions				
☐				
☐				
☐				

7) For each emission unit, if the alternative in use or selected for implementation is not the lowest in mercury emissions, describe why the lowest mercury emitting alternative is not in use or selected for use.

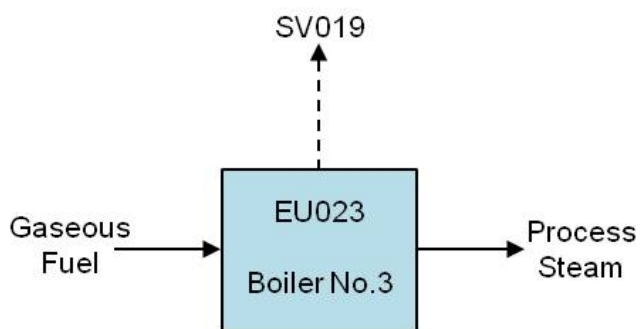
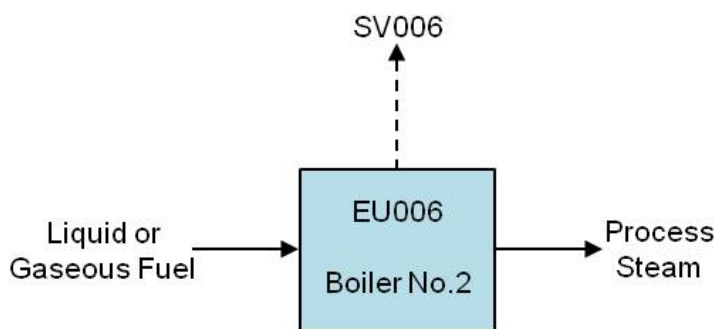
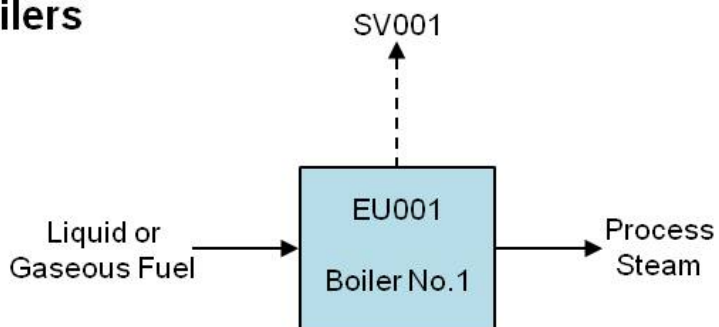
lowest natural gas and/or no. 2 diesel fuel Hg fuel options are proposed for this amendment resulting in a Hg emission reduction.

Higher Hg-containing no. 6 diesel fuel will be discontinued as part of this proposed amendment.



- 1) AQ Facility ID No.: **03700070**
- 2) Facility Name: **Sanimax USA Inc**
- 3) Flow Diagram:

Boilers



Legend

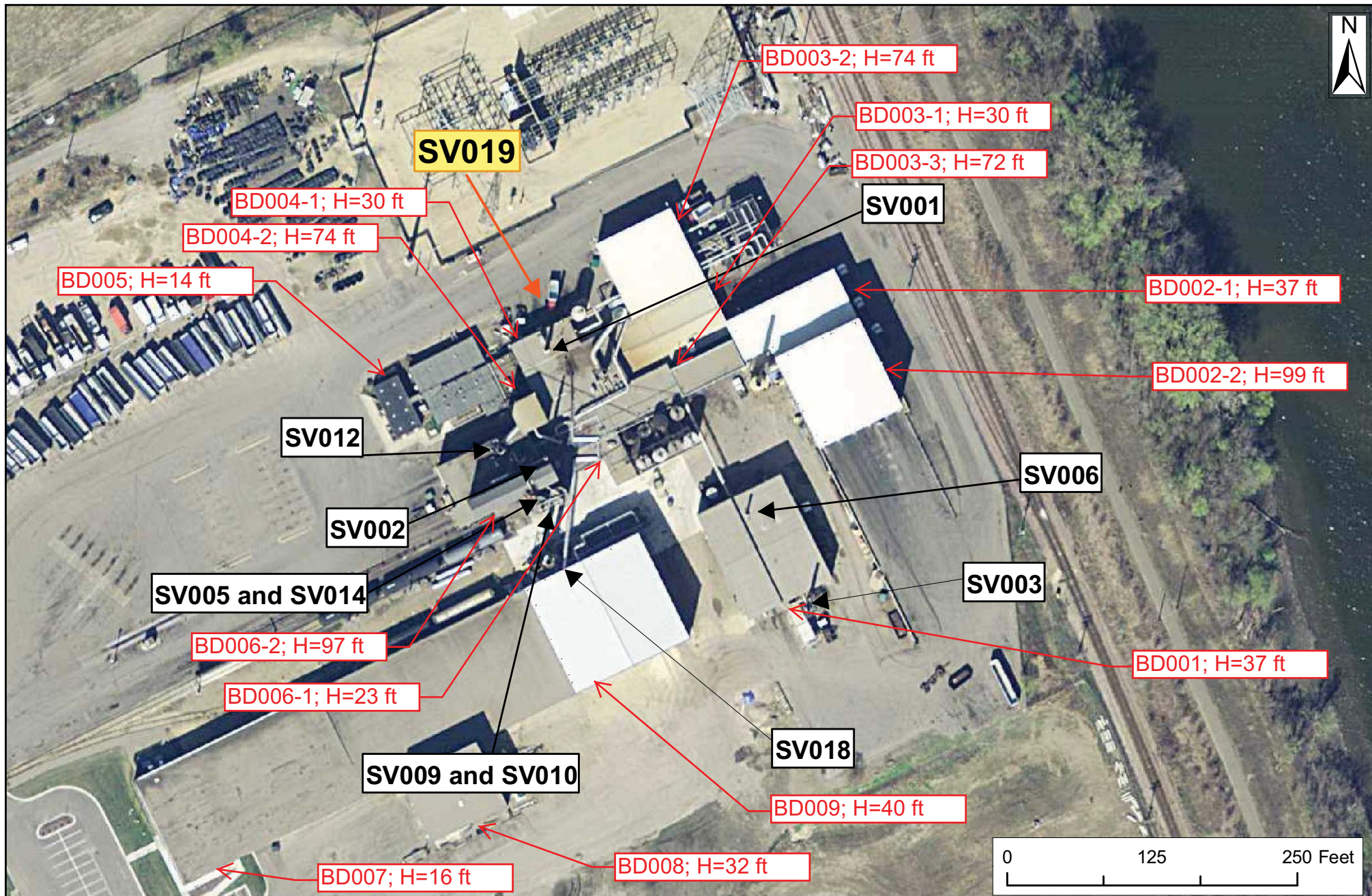
- Non-emitting Process Unit
- Emission Unit
- Control Equipment
- Process Line
- Emissions



AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **GI-03**
FACILITY AND STACK/VENT DIAGRAM
2/16/05

-
- 1) AQ Facility ID No.: 03700070
 - 2) Facility Name: Sanimax USA Inc
 - 3) Facility and Stack/Vent Diagram:



3535 VADNAIS CENTER DR.
ST. PAUL, MN 55110
PHONE: (651) 490-2000
FAX: (888) 908-8166
TF: (800) 325-2055
www.sehinc.com

Project: NACME 123033
Print Date: 1/10/2013

Map by: RB/bpt
Projection: UTM NAD83
Source: LMIC, USGS

Proposed Stack SV019 Stack Location
Sanimax USA Inc
Saint Paul, MN

Figure 1



Minnesota Pollution Control Agency

AIR QUALITY
520 LAFAYETTE ROAD
ST. PAUL, MN 55155-4194

PERMIT APPLICATION FORM **GI-04**
STACK/VENT INFORMATION
7/25/05

1) AQ Facility ID No.: 03700070 2) Facility Name: Sanimax USA Inc

3a) SV ID No.	3b) Operator's Description	3c) Height of Opening From Ground (ft.)	3d) Inside Diameter in ft. (left column only) or Length x Width in ft. (both columns)		3e) Design Flow Rate at Exit (acfm)	3f) Exit Gas Temperature (° F)	3g) Rate/Temp Information Source	3h) Discharge Direction
019	Boiler No. 3	100	2.67		11000	350	E	U
001	Boiler No. 1	100	3		20120	560	E	U
018	PPF	100	4		67710	90	E	U



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

GI-05A

Pollution Control Equipment Information
Air Quality Permit Program

Doc Type: Permit Application

Instructions on Page 2

1a) AQ Facility ID No.: 03700070

1b) AQ File No.: 578

2) Facility name: Sanimax USA Inc

3a) Control equip ID no.	3b) CE type code	3c) Description	3d) Manufacturer	3e) Model no.	3f) Pollutants controlled	3g) Capture efficiency	3h) Destruct/ collect efficiency	3i) Afterburner/ Oxidizer combustion parameters
001	053	Blood Process Venturi Scrubber	SCP Control	PT75K	PM/ PM10/ PM2.5	100%	90%	
003	053	PRF Venturi Scrubber	SCP Control	PT40K	PM/ PM10/ PM2.5	100%	90%	
012	053	Cookers Venturi Scrubber	SCP Control	PT18K	PM/ PM10/ PM2.5	100%	90%	



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

CD-05

**Compliance Plan for Control Equipment
Air Quality Permit Program**

Facility Information

1) **AQ Facility ID No.:** 03700070

2) **Facility Name:** Sanimax USA Inc

3) **Electrostatic Precipitators (includes wet electrostatic precipitators) (control codes 010, 011, 012, 128, 146)**

Complete the following information for each electrostatic precipitator not already included in an existing individual permit. For changes to parameters of electrostatic precipitators already included in an existing permit, attach a copy of the relevant permit page with proposed changes clearly marked.

CE Number:	Control Efficiency Basis (for control and capture efficiencies listed on Form GI-05A)	Using control equipment rule?	Voltage	Secondary Current	Minimum Fields Online	Using conditioning agent?	Conditioning agent flow rate, if applicable	Subject to CAM?	For a "Large" or "Other" PSEU?
		☐ No ☐ Yes				☐ No ☐ Yes		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes				☐ No ☐ Yes		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes				☐ No ☐ Yes		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes				☐ No ☐ Yes		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes				☐ No ☐ Yes		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA

CAM = Compliance Assurance Monitoring

PSEU = Pollutant specific emission unit

4) Fabric Filters (control codes 016, 017, 018)

Complete the following information for each fabric filter not already included in an existing individual permit. For changes to parameters for fabric filters already included in an existing permit, attach a copy of the relevant permit page with proposed changes clearly marked.

CE Number:	Control Efficiency Basis (for control and capture efficiencies listed on Form GI-05A)	Using control equipment rule?	Pressure Drop (inches of water column)	Bag leak detector in use?	Subject to CAM?	For a "Large" or "Other" PSEU?
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA

5) Panel/Wall Filters (including HEPA filters) (control codes 058, 101) Mechanically Aided Separators (control code 056, 113)

Complete the following information for each wall or panel filter not already included in an existing individual permit. For changes to parameters for filters already included in an existing permit, attach a copy of the relevant permit page with proposed changes clearly marked.

CE Number:	Control Efficiency Basis (for control and capture efficiencies listed on Form GI-05A)	Using control equipment rule?	Subject to CAM?	For a "Large" or "Other" PSEU?
		☐ Yes ☐ No	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ Yes ☐ No	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ Yes ☐ No	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ Yes ☐ No	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ Yes ☐ No	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ Yes ☐ No	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA

6) Cyclones/Multiclones (control code 007, 008, 009, 076)

Complete the following information for each cyclone or multiclone not already included in an existing individual permit. For changes to parameters for cyclones or multiclones already included in an existing permit, attach a copy of the relevant permit page with proposed changes clearly marked.

CE Number:	Control Efficiency Basis (for control and capture efficiencies listed on Form GI-05A)	Using control equipment rule?	Pressure Drop (inches of water column)	Subject to CAM?	For a "Large" or "Other" PSEU?
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA

7) Wet Cyclone Separator (control code 057, 085)

Complete the following information for each wet cyclone separator not already included in an existing individual permit. For changes to parameters for wet cyclone separators already included in an existing permit, attach a copy of the relevant permit page with proposed changes clearly marked.

CE Number:	Control Efficiency Basis (for control and capture efficiencies listed on Form GI-05A)	Using control equipment rule?	Pressure Drop (inches of water column)	Water pressure (psi)	Subject to CAM?	For a "Large" or "Other" PSEU?
		☐ No ☐ Yes			☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes			☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes			☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes			☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes			☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes			☐ Yes ☐ No	☐ Large ☐ Other ☐ NA

8) Spray Tower (control code 052), Venturi Scrubber (control code 053), Impingement Plate Scrubber (control code 055), or Charged Scrubber (control code 503)

Complete the following information for each wet scrubber not already included in an existing individual permit. For changes to parameters for wet scrubbers already included in an existing permit, attach a copy of the relevant permit page with proposed changes clearly marked.

CE Number:	Control Efficiency Basis (for control and capture efficiencies listed on Form GI-05A)	Using control equipment rule?	Pressure Drop (inches of water column)	Liquid flow rate (gal/min)	Subject to CAM?	For a "Large" or "Other" PSEU?
001	Facility estimate	☒ No ☐ Yes	3.5 to 7.0	at least 48	☐ Yes ☒ No	☐ Large ☐ Other ☒ NA
003	Facility estimate	☒ No ☐ Yes	3.5 to 7.0	at least 16	☐ Yes ☒ No	☐ Large ☐ Other ☒ NA
012	Facility estimate	☒ No ☐ Yes	3.5 to 7.0	at least 65	☐ Yes ☒ No	☐ Large ☐ Other ☒ NA
		☐ No ☐ Yes			☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes			☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes			☐ Yes ☐ No	☐ Large ☐ Other ☐ NA

9) Condensation Scrubber (control code 517)

Complete the following information for each condensation scrubber not already included in an existing individual permit. For changes to parameters for condensation scrubbers already included in an existing permit, attach a copy of the relevant permit page with proposed changes clearly marked.

CE Number:	Control Efficiency Basis (for control and capture efficiencies listed on Form GI-05A)	Using control equipment rule?	Pressure Drop (inches of water column)	Steam Supply rate (units)	Blowdown Rate (units)	Subject to CAM?	For a "Large" or "Other" PSEU?
		☐ No ☐ Yes				☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes				☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes				☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes				☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes				☐ Yes ☐ No	☐ Large ☐ Other ☐ NA

10) Thermal Oxidation (control code 021, 022, 131, 133, 510)

Complete the following information for each thermal oxidizer not already included in an existing individual permit. For changes to parameters for thermal oxidizers already included in an existing permit, attach a copy of the relevant permit page with proposed changes clearly marked.

CE Number:	Control Efficiency Basis (for control and capture efficiencies listed on Form GI-05A)	Using control equipment rule?	Combustion Temperature (degrees F)	Inlet and Outlet Temperatures (degrees F)	Residence Time (seconds)	Subject to CAM?	For a "Large" or "Other" PSEU?
		☐ No ☐ Yes		Inlet: _____ Outlet: _____		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		Inlet: _____ Outlet: _____		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		Inlet: _____ Outlet: _____		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		Inlet: _____ Outlet: _____		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		Inlet: _____ Outlet: _____		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA

11) Catalytic Oxidation (control code 019, 020, 109, 116, 509)

Complete the following information for each catalytic oxidizer not already included in an existing individual permit. For changes to parameters for catalytic oxidizers already included in an existing permit, attach a copy of the relevant permit page with proposed changes clearly marked.

CE Number:	Control Efficiency Basis (for control and capture efficiencies listed on Form GI-05A)	Using control equipment rule?	Catalyst Bed Reactivity (units)	Inlet and Outlet Temperatures (degrees F)	Subject to CAM?	For a "Large" or "Other" PSEU?
		☐ No ☐ Yes		Inlet: _____ Outlet: _____	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		Inlet: _____ Outlet: _____	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		Inlet: _____ Outlet: _____	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		Inlet: _____ Outlet: _____	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		Inlet: _____ Outlet: _____	☐ Yes ☐ No	☐ Large ☐ Other ☐ NA

12) Vapor Recovery Systems (including condensers) (control code 047)

Complete the following information for each vapor recovery system not already included in an existing individual permit. For changes to parameters for vapor recovery systems already included in an existing permit, attach a copy of the relevant permit page with proposed changes clearly marked.

CE Number:	Control Efficiency Basis (for control and capture efficiencies listed on Form GI-05A)	Temperature Range (degrees F)	Condenser Pressure Drop Range (inches of water column)	Filter Pressure Drop Range (inches of water column)	Subject to CAM?	For a "Large" or "Other" PSEU?
					☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
					☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
					☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
					☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
					☐ Yes ☐ No	☐ Large ☐ Other ☐ NA

13) Flaring (control code 023)

Complete the following information for each flare not already included in an existing individual permit. For changes to parameters for cyclones or multicyclones already included in an existing permit, attach a copy of the relevant permit page with proposed changes clearly marked.

CE Number:	Control Efficiency Basis (for control and capture efficiencies listed on Form GI-05A)	Using control equipment rule?	Temperature (indicating presence of flame) (degrees F)	Subject to CAM?	For a "Large" or "Other" PSEU?
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
		☐ No ☐ Yes		☐ Yes ☐ No	☐ Large ☐ Other ☐ NA

13) Other Controls

Complete the following information for each control device not described above and not already included in an existing individual permit. For changes to parameters for any other control devices that are already included in an existing permit, attach a copy of the relevant permit page with proposed changes clearly marked.

CE Number:	Control Efficiency Basis (for control and capture efficiencies listed on Form GI-05A)	Operating Parameters (describe)	Subject to CAM?	For a "Large" or "Other" PSEU?
			☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
			☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
			☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
			☐ Yes ☐ No	☐ Large ☐ Other ☐ NA
			☐ Yes ☐ No	☐ Large ☐ Other ☐ NA



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

GI-05B

Emission Unit Information
Air Quality Permit Program

Doc Type: Permit Application

Instructions on Page 3

1a) AQ Facility ID No.: 03700070 **1b)** AQ File No.: 578

2) Facility Name: Sanimax USA Inc

3a) Emis Unit ID No.	3b) SV ID No(s).	3c) Relation Type	3d) Control Equip ID No.	3e) Emission Unit Operator's Description	3f) Manufacturer	3g) Model No.
023	019	(M)ain		Boiler No. 3	York Shipley	382L-S2D-900X-250

[illegible]

Appendix B

Emission Calculations

Sanimax USA Inc
Facility PTE Summary

Emission Unit	Stack / Vent	Pollutant																			
		PM		PM ₁₀		PM _{2.5}		SO ₂		NOx		CO		VOC		CO ₂ e		Single HAP*		All HAPs	
		(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Existing																					
EU001	SV001	5.81	25.46	5.00	21.89	3.25	14.26	80.07	350.71	18.70	81.91	4.20	18.40	0.28	1.20	8,995	39,397	0.09	0.39	0.09	0.41
EU002	SV002	1.43	6.24	1.26	5.51	0.74	3.23	2.54	11.11	0.71	3.13	0.41	1.80	0.12	0.51	800	3,504	0.01	0.04	0.01	0.04
EU003	SV003	1.06	4.62	1.02	4.45	0.97	4.23	--	--	--	--	--	--	0.17	0.74	--	--	--	--	--	--
EU005	SV005	0.01	0.03	0.005	0.02	0.005	0.02	--	--	--	--	--	--	--	--	--	--	--	--	--	--
EU006	SV006	0.25	1.10	0.13	0.57	0.03	0.14	8.92	39.05	2.51	11.00	1.45	6.34	0.09	0.42	2,813	12,320	0.03	0.14	0.03	0.14
EU009	SV009	0.07	0.32	0.05	0.20	0.05	0.20	--	--	--	--	--	--	--	--	--	--	--	--	--	--
EU010	SV010	0.07	0.32	0.05	0.20	0.05	0.20	--	--	--	--	--	--	--	--	--	--	--	--	--	--
EU011	SV012	0.34	1.47	0.28	1.25	0.10	0.44	--	--	--	--	--	--	--	--	--	--	--	--	--	--
EU012	SV012	1.00	4.38	0.90	3.92	0.51	2.23	--	--	--	--	--	--	1.06	4.66	--	--	--	--	--	--
EU013	SV012	1.00	4.38	0.90	3.92	0.51	2.23	--	--	--	--	--	--	1.06	4.66	--	--	--	--	--	--
EU014	SV014	0.01	0.04	0.01	0.03	0.01	0.03	--	--	--	--	--	--	--	--	--	--	--	--	--	--
EU020	SV018	1.52	6.64	1.36	5.94	0.77	3.39	--	--	--	--	--	--	0.16	0.71	--	--	--	--	--	--
EU021	SV018	0.43	1.88	0.38	1.68	0.22	0.96	--	--	--	--	--	--	0.05	0.20	--	--	--	--	--	--
EU022	SV018	0.17	0.72	0.14	0.61	0.05	0.22	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Existing PTE		13.15	57.60	11.46	50.19	7.25	31.77	91.52	240**	21.93	96.03	6.06	26.54	2.99	13.11	12,607	55,220	0.13	0.57	0.14	0.60
Proposed/Revised																					
EU001	SV001	0.80	3.51	0.40	1.75	0.39	1.71	5.69	24.91	8.01	35.09	4.20	18.40	0.45	1.95	8,964	39,264	0.09	0.39	0.09	0.41
EU002	SV002	1.43	6.28	1.26	5.52	0.77	3.36	0.56	2.44	0.79	3.44	0.41	1.80	0.24	1.07	879	3,849	0.01	0.04	0.01	0.04
EU006	SV006	0.28	1.21	0.14	0.60	0.13	0.59	1.96	8.59	2.76	12.09	1.45	6.34	0.15	0.67	3,090	13,535	0.03	0.14	0.03	0.14
EU023	SV019	0.53	2.32	0.28	1.24	0.28	1.24	0.61	2.66	5.29	23.15	3.05	13.35	0.32	1.42	5,915	25,907	0.07	0.29	0.07	0.30
Difference		-4.45	-19.50	-4.30	-18.86	-2.45	-10.73	-82.71	-201.40	-5.08	-22.26	3.05	13.35	0.68	2.98	6,241	27,335	0.07	0.29	0.07	0.30
Proposed PTE		8.70	38.10	7.15	31.34	4.81	21.05	8.81	38.60	16.84	73.77	9.11	39.89	3.67	16.08	18,848	82,556	0.20	0.85	0.21	0.90

*Largest single HAP is hexane from natural gas combustion.

** Facility is currently subject to a 240 tpy SO₂ limit.

Propane sulfur content from Santa Barbara County Air Pollution Control District "Technical Information and References, Gaseous Fuel SOx Emission Factor (v. 1.0, 1/31/97) [<http://www.sbcapcd.org/eng/tech/sulfur01.htm>]

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Sanimax													
Boiler No. 3 - EU023 (SV019)													
Combustion Emissions Calculations													
All Emission Factors from AP-42, unless otherwise noted.													
Capacity:		37 MMBtu/hr =	900 hp										
#2 Fuel Oil:		0.264276276 1000 gal/hr		#2 Fuel Oil Heating Value:		0.140005 MMBtu/gal			S (No. 2):		0.0015 %		
Propane:		0.404371585 1000 gal/hr		Propane Heating Value:		0.0915 MMBtu/gal			S (propane):		15 gr/100 scf		
Natural Gas:		0.03627451 MMcf/hr		Natural Gas Heating Value:		1020 MMBtu/cf							
		Natural Gas Emission Factor (lb/MMcf)	#2 Oil Emission Factor (lb/1000 gal)	Propane Emission Factor (lb/1000 gal)	Natural Gas Hourly Potential (lb/hr)	#2 Oil Hourly Potential (lb/hr)	Propane Hourly Potential (lb/hr)	Worst Case Emissions (lb/hr)	Unrestricted Potential (tpy)	Limited Potential (tpy)			
EU023 Boiler 3 Fuels: Distillate (#2) Fuel Oil, Natural Gas, Propane	Acenaphthene	1.80E-06	2.11E-05	Use natural gas emission factors for HAPs and lead as a conservative estimate for propane.	6.53E-08	5.58E-06	6.53E-08	5.58E-06	2.44E-05	2.44E-05			
	Acenaphthylene	1.80E-06	2.53E-07		6.53E-08	6.69E-08	6.53E-08	6.69E-08	2.93E-07	2.93E-07			
	Anthracene	2.40E-06	1.22E-06		8.71E-08	3.22E-07	8.71E-08	3.22E-07	1.41E-06	1.41E-06			
	benz(a)anthracene	1.80E-06	4.01E-06		6.53E-08	1.06E-06	6.53E-08	1.06E-06	4.64E-06	4.64E-06			
	Benzene	2.10E-03	2.14E-04		7.62E-05	5.66E-05	7.62E-05	7.62E-05	3.34E-04	3.34E-04			
	Benzo(a)pyrene	1.20E-06			4.35E-08		4.35E-08	4.35E-08	1.91E-07	1.91E-07			
	Benzo(b)fluoranthene	1.80E-06	1.48E-06		6.53E-08	3.91E-07	6.53E-08	3.91E-07	1.71E-06	1.71E-06			
	Benzo(g,h,i)perylene	1.20E-06	2.26E-06		4.35E-08	5.97E-07	4.35E-08	5.97E-07	2.62E-06	2.62E-06			
	Benzo(k)fluoranthene	1.80E-06	1.48E-06		6.53E-08	3.91E-07	6.53E-08	3.91E-07	1.71E-06	1.71E-06			
	Chrysene	1.80E-06	2.38E-06		6.53E-08	6.29E-07	6.53E-08	6.29E-07	2.75E-06	2.75E-06			
	Dibenz(a,h)anthracene	1.20E-03	1.67E-06		4.35E-05	4.41E-07	4.35E-05	4.35E-05	1.91E-04	1.91E-04			
	Dichlorobenzene	1.20E-03			4.35E-05		4.35E-05	4.35E-05	1.91E-04	1.91E-04			
	7,12-Dimethylbenz(a)anthracene	1.60E-05			5.80E-07		5.80E-07	5.80E-07	2.54E-06	2.54E-06			
	Ethylbenzene		6.36E-05			1.68E-05		1.68E-05	7.36E-05	7.36E-05			
	Fluoranthene	3.00E-06	4.84E-06			1.09E-07	1.28E-06	1.09E-07	1.28E-06	5.60E-06	5.60E-06		
	Fluorene	2.80E-06	4.47E-06			1.02E-07	1.18E-06	1.02E-07	1.18E-06	5.17E-06	5.17E-06		
	Formaldehyde	7.50E-02	3.30E-02			2.72E-03	8.72E-03	2.72E-03	8.72E-03	3.82E-02	3.82E-02		
	Hexane	1.80E+00				6.53E-02		6.53E-02	6.53E-02	2.86E-01	2.86E-01		
	Indeno(1,2,3-cd)pyrene	1.80E-06	2.14E-06			6.53E-08	5.66E-07	6.53E-08	5.66E-07	2.48E-06	2.48E-06		
	2-Methylnaphthalene	2.40E-05				8.71E-07	0.00E+00	8.71E-07	8.71E-07	3.81E-06	3.81E-06		
	3-Methylchloranthrene	1.80E-06				6.53E-08		6.53E-08	6.53E-08	2.86E-07	2.86E-07		
	Naphthalene	6.10E-04	1.13E-03			2.21E-05	2.99E-04	2.21E-05	2.99E-04	1.31E-03	1.31E-03		
	Phenanthrene	1.70E-05	1.05E-05			6.17E-07	2.77E-06	6.17E-07	2.77E-06	1.22E-05	1.22E-05		
	Phosphorus								0.00E+00	0.00E+00	0.00E+00		
	Pyrene	5.00E-06	4.25E-06			1.81E-07	1.12E-06	1.81E-07	1.12E-06	4.92E-06	4.92E-06		
	Toluene	3.40E-03	6.20E-03			1.23E-04	1.64E-03	1.23E-04	1.64E-03	7.18E-03	7.18E-03		
	1,1,1-Trichloroethane		2.36E-04				6.24E-05		6.24E-05	2.73E-04	2.73E-04		
	Xylenes		1.09E-04				2.88E-05		2.88E-05	1.26E-04	1.26E-04		
	Antimony compounds	5.25E-03				1.90E-04		1.90E-04	1.90E-04	8.34E-04	8.34E-04		
	Arsenic compounds	2.00E-04	5.60E-10			7.25E-06	1.48E-10	7.25E-06	7.25E-06	3.18E-05	3.18E-05		
	Beryllium compounds	1.20E-05	4.20E-10			4.35E-07	1.11E-10	4.35E-07	4.35E-07	1.91E-06	1.91E-06		
	Cadmium compounds	1.10E-03	4.20E-10			3.99E-05	1.11E-10	3.99E-05	3.99E-05	1.75E-04	1.75E-04		
	Chromium compounds	1.40E-03	4.20E-10			5.08E-05	1.11E-10	5.08E-05	5.08E-05	2.22E-04	2.22E-04		
	Cobalt compounds	8.40E-05				3.05E-06		3.05E-06	3.05E-06	1.33E-05	1.33E-05		
	Manganese compounds	3.80E-04	8.40E-10			1.38E-05	2.22E-10	1.38E-05	1.38E-05	6.04E-05	6.04E-05		
	Mercury compounds	2.60E-04	4.20E-10			9.43E-06	1.11E-10	9.43E-06	9.43E-06	4.13E-05	4.13E-05		
	Nickel compounds	2.10E-03	4.20E-10			7.62E-05	1.11E-10	7.62E-05	7.62E-05	3.34E-04	3.34E-04		
	Selenium compounds	2.40E-05	2.10E-09			8.71E-07	5.55E-10	8.71E-07	8.71E-07	3.81E-06	3.81E-06		
	HAPs					0.07	0.01	0.07	0.07	0.30	0.30		
	Lead	5.00E-04	1.26E-09			1.81E-05	3.33E-10	1.81E-05	1.81E-05	7.94E-05	7.94E-05		
	Total PM	7.60E+00	2.00E+00		7.00E-01	0.28	0.53	0.28	0.53	2.32	2.32		
	PM ₁₀	7.60E+00	1.00E+00		7.00E-01	0.28	0.26	0.28	0.28	1.24	1.24		
	PM _{2.5}	7.60E+00	2.50E-01		7.00E-01	0.28	0.07	0.28	0.28	1.24	1.24		
	SO ₂	6.00E-01	2.13E-01		1.50E+00	0.02	0.06	0.61	0.61	2.66	2.66		
	NOx	5.00E+01	2.00E+01		1.30E+01	1.81	5.29	5.26	5.29	23.15	23.15		
VOC	5.50E+00	2.00E-01	8.00E-01	0.20	0.05	0.32	0.32	1.42	1.42				
CO	8.40E+01	5.00E+00	7.50E+00	3.05	1.32	3.03	3.05	13.35	13.35				
CO ₂	1.20E+05	2.23E+04	1.25E+04	4.353	5.893	5.055	5.893	25.813	25,813				
CH ₄	2.30E+00	5.20E-02	2.00E-01	0.08	0.01	0.08	0.08	0.37	0.37				
N ₂ O	2.20E+00	2.60E-01	9.00E-01	0.08	0.07	0.36	0.36	1.59	1.59				
GHG				4,353	5,893	5,055	5,893	25,813	25,813				
CO ₂ e				4,379	5,915	5,169	5,915	25,907	25,907				
Propane sulfur content from Santa Barbara County Air Pollution Control District *Technical Information and References, Gaseous Fuel SOx Emission Factor (v. 1.0, 1/31/97)													
[http://www.sbcapcd.org/eng/tech/sulfur01.htm]													
	Proposed PTE												
		Total (lb/hr)	Total (tpy)										
	CO ₂	18,780	82,254										
	CH ₄	0.32	1.42										
	N ₂ O	1.09	4.76										
	GHG	18,781	82,261										
	CO ₂ e	19,124	83,761										

Sanimax
Hazardous Air Pollutants
Combustion Emissions Summary

Name	CAS No.	EU001		EU002		EU006		EU023		Total	
		(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Acenaphthene	83-32-9	8.45E-06	3.70E-05	8.29E-07	3.63E-06	2.91E-06	1.28E-05	5.58E-06	2.44E-05	1.78E-05	7.78E-05
Acenaphthylene	203-96-8	1.01E-07	4.44E-07	9.93E-09	4.35E-08	3.49E-08	1.53E-07	6.69E-08	2.93E-07	2.13E-07	9.33E-07
Anthracene	120-12-7	4.89E-07	2.14E-06	4.79E-08	2.10E-07	1.68E-07	7.38E-07	3.22E-07	1.41E-06	1.03E-06	4.50E-06
benz(a)anthracene	56-55-3	1.61E-06	7.03E-06	1.57E-07	6.90E-07	5.54E-07	2.42E-06	1.06E-06	4.64E-06	3.38E-06	1.48E-05
Benzene	71-43-2	1.05E-04	4.60E-04	1.03E-05	4.51E-05	3.62E-05	1.59E-04	7.62E-05	3.34E-04	2.28E-04	9.97E-04
Benzo(a)pyrene	50-32-8	6.00E-08	2.63E-07	5.88E-09	2.58E-08	2.07E-08	9.06E-08	4.35E-08	1.91E-07	1.30E-07	5.70E-07
Benzo(b)fluoranthene	205-99-2	5.93E-07	2.60E-06	5.81E-08	2.55E-07	2.04E-07	8.95E-07	3.91E-07	1.71E-06	1.25E-06	5.46E-06
Benzo(g,h,i)perylene	191-24-2	9.05E-07	3.96E-06	8.87E-08	3.89E-07	3.12E-07	1.37E-06	5.97E-07	2.62E-06	1.90E-06	8.34E-06
Benzo(k)fluoranthene	205-82-3	5.93E-07	2.60E-06	5.81E-08	2.55E-07	2.04E-07	8.95E-07	3.91E-07	1.71E-06	1.25E-06	5.46E-06
Chrysene	218-01-9	9.53E-07	4.18E-06	9.35E-08	4.09E-07	3.29E-07	1.44E-06	6.29E-07	2.75E-06	2.00E-06	8.78E-06
Dibenzo(a,h)anthracene	53-70-3	6.00E-05	2.63E-04	5.88E-06	2.58E-05	2.07E-05	9.06E-05	4.35E-05	1.91E-04	1.30E-04	5.70E-04
Dichlorobenzene	106-46-7	6.00E-05	2.63E-04	5.88E-06	2.58E-05	2.07E-05	9.06E-05	4.35E-05	1.91E-04	1.30E-04	5.70E-04
7,12-Dimethylbenz(a)anthracene	57-97-6	8.00E-07	3.50E-06	7.84E-08	3.44E-07	2.76E-07	1.21E-06	5.80E-07	2.54E-06	1.73E-06	7.60E-06
Ethylbenzene	100-41-4	2.55E-05	1.12E-04	2.50E-06	1.09E-05	8.78E-06	3.85E-05	1.68E-05	7.36E-05	5.36E-05	2.35E-04
Fluoranthene	206-44-0	1.94E-06	8.49E-06	1.90E-07	8.32E-07	6.68E-07	2.93E-06	1.28E-06	5.60E-06	4.08E-06	1.79E-05
Fluorene	86-73-7	1.79E-06	7.84E-06	1.76E-07	7.69E-07	6.17E-07	2.70E-06	1.18E-06	5.17E-06	3.76E-06	1.65E-05
Formaldehyde	50-00-0	1.32E-02	5.79E-02	1.30E-03	5.68E-03	4.56E-03	2.00E-02	8.72E-03	3.82E-02	2.78E-02	1.22E-01
Hexane	110-54-3	9.00E-02	3.94E-01	8.82E-03	3.86E-02	3.10E-02	1.36E-01	6.53E-02	2.86E-01	1.95E-01	8.55E-01
Indendo(1,2,3-cd)pyrene	193-39-5	8.57E-07	3.75E-06	8.40E-08	3.68E-07	2.95E-07	1.29E-06	5.66E-07	2.48E-06	1.80E-06	7.89E-06
2-Methylnaphthalene	91-57-6	1.20E-06	5.26E-06	1.18E-07	5.15E-07	4.14E-07	1.81E-06	8.71E-07	3.81E-06	2.60E-06	1.14E-05
3-Methylchloranthrene	56-49-5	9.00E-08	3.94E-07	8.82E-09	3.86E-08	3.10E-08	1.36E-07	6.53E-08	2.86E-07	1.95E-07	8.55E-07
Naphthalene	91-20-3	4.53E-04	1.98E-03	4.44E-05	1.94E-04	1.56E-04	6.83E-04	2.99E-04	1.31E-03	9.52E-04	4.17E-03
Phenanthrene	85-01-8	4.21E-06	1.84E-05	4.12E-07	1.81E-06	1.45E-06	6.35E-06	2.77E-06	1.22E-05	8.84E-06	3.87E-05
Pyrene	129-00-0	1.70E-06	7.46E-06	1.67E-07	7.31E-07	5.87E-07	2.57E-06	1.12E-06	4.92E-06	3.58E-06	1.57E-05
Toluene	108-88-3	2.48E-03	1.09E-02	2.43E-04	1.07E-03	8.56E-04	3.75E-03	1.64E-03	7.18E-03	5.22E-03	2.29E-02
1,1,1-Trichloroethane	71-55-6	9.45E-05	4.14E-04	9.27E-06	4.06E-05	3.26E-05	1.43E-04	6.24E-05	2.73E-04	1.99E-04	8.70E-04
Xylenes	1330-20-7	4.37E-05	1.91E-04	4.28E-06	1.87E-05	1.50E-05	6.59E-05	2.88E-05	1.26E-04	9.18E-05	4.02E-04
Antimony compounds	7440-36-0	2.63E-04	1.15E-03	2.57E-05	1.13E-04	9.05E-05	3.96E-04	1.90E-04	8.34E-04	5.69E-04	2.49E-03
Arsenic compounds	7440-38-2	1.00E-05	4.38E-05	9.80E-07	4.29E-06	3.45E-06	1.51E-05	7.25E-06	3.18E-05	2.17E-05	9.50E-05
Beryllium compounds	7440-41-7	6.00E-07	2.63E-06	5.88E-08	2.58E-07	2.07E-07	9.06E-07	4.35E-07	1.91E-06	1.30E-06	5.70E-06
Cadmium compounds	7440-43-9	5.50E-05	2.41E-04	5.39E-06	2.36E-05	1.90E-05	8.30E-05	3.99E-05	1.75E-04	1.19E-04	5.22E-04
Chromium compounds	7440-47-3	7.00E-05	3.07E-04	6.86E-06	3.01E-05	2.41E-05	1.06E-04	5.08E-05	2.22E-04	1.52E-04	6.65E-04
Cobalt compounds	7440-48-4	4.20E-06	1.84E-05	4.12E-07	1.80E-06	1.45E-06	6.34E-06	3.05E-06	1.33E-05	9.11E-06	3.99E-05
Manganese compounds	7439-96-5	1.90E-05	8.32E-05	1.86E-06	8.16E-06	6.55E-06	2.87E-05	1.38E-05	6.04E-05	4.12E-05	1.80E-04
Mercury compounds	7439-97-6	1.30E-05	5.69E-05	1.27E-06	5.58E-06	4.48E-06	1.96E-05	9.43E-06	4.13E-05	2.82E-05	1.23E-04
Nickel compounds	7440-02-0	1.05E-04	4.60E-04	1.03E-05	4.51E-05	3.62E-05	1.59E-04	7.62E-05	3.34E-04	2.28E-04	9.97E-04
Selenium compounds	7782-49-2	1.20E-06	5.26E-06	1.18E-07	5.15E-07	4.14E-07	1.81E-06	8.71E-07	3.81E-06	2.60E-06	1.14E-05

Sanimax
Blood/Ring Dryer - EU002 (SV002)
Process Emissions Calculations

Process Emissions: Blood Drying

Pollutant	Emission Factors (lb/ton)			Process Capacity (lbs/hr)	Controlled Emission Rates	
	Filterable	Condensable	Total		(lbs/hr)	(tons/yr)
PM ^[1]	0.89	0.46	1.35	2,000	1.35	5.93
PM₁₀ ^[2]	0.76	0.46	1.22		1.22	5.34
PM_{2.5} ^[3]	0.27	0.46	0.73		0.73	3.19
VOC ^[4]	NA	NA	0.09		0.09	0.39

^[1] PM filterable emission factor is calculated from PM/PM₁₀ ratio of 100/85 as no AP-42 factor is available. PM condensable is taken from AP-42 Table 9.5.3-2

^[2] PM₁₀ filterable is taken from AP-42 Table 9.5.3-2 PM₁₀ condensable is 100% of PM condensable emission factor

^[3] PM_{2.5} filterable is calculated from PM_{2.5}/PM₁₀ ratio of 30/85, taken from EPA PM calculator based on SCC code 30203801 (Animal/Poultry Rendering - General:Uncontrolled). PM_{2.5} condensable is 100% of PM condensable emission factor.

^[4] VOC emission factor from Air Pollutant Emission Inventory Report 2009

Sanimax
Protein Recovery Facility (PRF) - EU003 (SV003)
PM, PM₁₀ and PM_{2.5} Emissions Calculations

Drying

Pollutant	Emission Factors (lb/ton)			Process Capacity (lbs/hr)	Controlled Emission Rates	
	Filterable	Condensable	Total		(lbs/hr)	(tons/yr)
PM ^[1]	-	-	0.87	2,000	0.87	3.81
PM ₁₀ ^[2]	-	-	0.87		0.87	3.81
PM _{2.5} ^[2]	-	-	0.87		0.87	3.81
VOC ^[3]	NA	NA	0.085		0.09	0.37

^[1] Performance test data showing 0.87 lb PM per ton of feathers processed (Braun Intertec Report: Central Bi-Products, Redwood Falls, Minnesota, June 1995)

^[2] PM₁₀ and PM_{2.5} emission factors assumed 100% of PM emission factor

^[3] VOC emission factor from Air Pollutant Emission Inventory Report 2009

Cooking

Pollutant	Emission Factors (lb/ton)			Process Capacity (lbs/hr)	Uncontrolled Emission Rate (lbs/hr)	Control Efficiency (%)	Controlled Emission Rates	
	Filterable	Condensable	Total				(lbs/hr)	(tons/yr)
PM ^[1]	0.56	0.24	0.80	2,000	0.80	90	0.08	0.35
PM ₁₀ ^[2]	0.48	0.24	0.72		0.72	90	0.07	0.31
PM _{2.5} ^[3]	0.17	0.24	0.41		0.41	90	0.04	0.18
VOC ^[4]	NA	NA	0.085		0.09	NA	0.09	0.37

^[1] PM filterable and condensable emission factors taken from AP-42 Table 9.13.3-2 for "Continuous Deep Fat Fryer - Other Snack Chips"

^[2] PM₁₀ filterable is calculated as 85% of PM filterable, taken from EPA PM calculator based on SCC code 30203803 (Animal/Poultry Rendering - Cooking:Uncontrolled). PM₁₀ condensable is 100% of PM condensable emission factor.

^[3] PM_{2.5} filterable is calculated as 30% of PM filterable, taken from EPA PM calculator based on SCC code 30203803 (Animal/Poultry Rendering - Cooking:Uncontrolled). PM_{2.5} condensable is 100% of PM condensable emission factor.

^[4] VOC emission factor from Air Pollutant Emission Inventory Report 2009

Conveying

Pollutant	Emission Factors (lb/ton)			Process Capacity (lbs/hr)	Uncontrolled Emission Rate (lbs/hr)	Control Efficiency (%)	Controlled Emission Rates	
	Filterable	Condensable	Total				(lbs/hr)	(tons/yr)
PM ^[1]	-	-	0.72	2,000	0.72	90	0.07	0.32
PM ₁₀ ^[2]	-	-	0.46		0.46	90	0.05	0.20
PM _{2.5} ^[3]	-	-	0.46		0.46	90	0.05	0.20

^[1] PM emission factor taken from AP-42 Table 11.12-2 "Pneumatic Unloading of Cement to Elevated Storage Silo"

^[2] PM₁₀ emission factor taken from AP-42 Table 11.12-2 "Pneumatic Unloading of Cement to Elevated Storage Silo"

^[3] PM_{2.5} emissions factor is calculated as 100% of PM₁₀ as no AP-42 emission factor is available.

Milling

Pollutant	Emission Factors (lb/ton)			Process Capacity (lbs/hr)	Uncontrolled Emission Rate (lbs/hr)	Control Efficiency (%)	Controlled Emission Rates	
	Filterable	Condensable	Total				(lbs/hr)	(tons/yr)
PM ^[1]	0.34	-	0.34	2,000	0.34	90	0.03	0.15
PM ₁₀ ^[2]	0.28	-	0.28		0.28	90	0.03	0.12
PM _{2.5} ^[3]	0.10	-	0.10		0.10	90	0.01	0.04

^[1] PM filterable emission factors taken from AP-42 Table 9.9.1-2 for "Hammermill - Cyclone Control" and assumes 80% cyclone control efficiency = 0.067/(1-0.8)

^[2] PM₁₀ filterable is calculated as 85% of PM filterable, taken from EPA PM calculator based on SCC code 30203801 (Animal/Poultry Rendering - General:Uncontrolled).

^[3] PM_{2.5} filterable is calculated as 30% of PM filterable, taken from EPA PM calculator based on SCC code 30203801 (Animal/Poultry Rendering - General:Uncontrolled).

Total Controlled PRF Emissions

Pollutant	Process Emission Rate (lbs/hr)	Maximum Unlimited (tons/yr)	Limited Potential (tons/yr)
	(lbs/hr)	(tons/yr)	(tons/yr)
PM	1.06	4.62	4.62
PM ₁₀	1.02	4.45	4.45
PM _{2.5}	0.97	4.23	4.23
VOC	0.17	0.74	0.74

Sanimax
Blood Pneumatic Conveying System - EU005 (SV005)
PM, PM₁₀ and PM_{2.5} Emissions Calculations

Conveying

Pollutant	Emission Factors (lb/ton)			Process Capacity (lbs/hr)	Uncontrolled Emission Rate (lbs/hr)	Air Flow (dscfm)	Emission Factor ^[1] (gr/dscf)	Controlled Emission Rates		Control Efficiency (%)	Requested Control Efficiency (%)	Controlled Emission Rates	
	Filterable	Condensable	Total					(lbs/hr)	(tons/yr)			(lbs/hr)	(tons/yr)
PM ^[2]	-	-	0.72	2,000	0.72	240	0.002	0.004	0.018	99.4%	99%	0.007	0.032
PM ₁₀ ^[3]	-	-	0.46		0.46			0.004	0.018	99.1%	99%	0.005	0.020
PM _{2.5} ^[4]	-	-	0.46		0.46			0.004	0.018	99.1%	99%	0.005	0.020

^[1] See attached emission statement

^[2] PM emission factor taken from AP-42 Table 11.12-2 "Pneumatic Unloading of Cement to Elevated Storage Silo"

^[3] PM₁₀ emission factor taken from AP-42 Table 11.12-2 "Pneumatic Unloading of Cement to Elevated Storage Silo"

^[4] PM_{2.5} emissions factor is calculated as 100% of PM₁₀ as no AP-42 emission factor is available.

Sanimax
Protein Silos (EU009 & EU010)
PM, PM₁₀ and PM_{2.5} Emissions Calculations

Silo EU009 (SV009)

Pollutant	Emission Factors (lb/ton)			Process Capacity (lbs/hr)	Uncontrolled Emission Rate (lbs/hr)	Air Flow (dscfm)	Emission Factor ^[1] (gr/dscf)	Controlled Emission Rates		Control Efficiency (%)	Requested Control Efficiency (%)	Controlled Emission Rates	
	Filterable	Condensable	Total					(lbs/hr)	(tons/yr)			(lbs/hr)	(tons/yr)
PM ^[2]	-	-	0.72	20,000	7.20	566	0.002	0.010	0.042	99.9%	99%	0.072	0.315
PM ₁₀ ^[3]	-	-	0.46		4.60			0.010	0.042	99.8%	99%	0.046	0.201
PM _{2.5} ^[4]	-	-	0.46		4.60			0.010	0.042	99.8%	99%	0.046	0.201

^[1] See attached emission statement

^[2] PM emission factor taken from AP-42 Table 11.12-2 "Pneumatic Unloading of Cement to Elevated Storage Silo"

^[3] PM₁₀ emission factor taken from AP-42 Table 11.12-2 "Pneumatic Unloading of Cement to Elevated Storage Silo"

^[4] PM_{2.5} emissions factor is calculated as 100% of PM₁₀ as no AP-42 emission factor is available.

Silo EU010 (SV010)

Pollutant	Emission Factors (lb/ton)			Process Capacity (lbs/hr)	Uncontrolled Emission Rate (lbs/hr)	Air Flow (dscfm)	Emission Factor ^[1] (gr/dscf)	Controlled Emission Rates		Control Efficiency (%)	Requested Control Efficiency (%)	Controlled Emission Rates	
	Filterable	Condensable	Total					(lbs/hr)	(tons/yr)			(lbs/hr)	(tons/yr)
PM ^[2]	-	-	0.72	20,000	7.20	566	0.002	0.010	0.042	99.9%	99%	0.072	0.315
PM ₁₀ ^[3]	-	-	0.46		4.60			0.010	0.042	99.8%	99%	0.046	0.201
PM _{2.5} ^[4]	-	-	0.46		4.60			0.010	0.042	99.8%	99%	0.046	0.201

^[1] See attached emission statement

^[2] PM emission factor taken from AP-42 Table 11.12-2 "Pneumatic Unloading of Cement to Elevated Storage Silo"

^[3] PM₁₀ emission factor taken from AP-42 Table 11.12-2 "Pneumatic Unloading of Cement to Elevated Storage Silo"

^[4] PM_{2.5} emissions factor is calculated as 100% of PM₁₀ as no AP-42 emission factor is available.

Sanimax
Cooking Process - EU011, EU012 and EU013 (SV012)
PM, PM₁₀ and PM_{2.5} Emissions Calculations

Milling Process - EU011

Pollutant	Emission Factors (lb/ton)			Process Capacity (lbs/hr)	Uncontrolled Emission Rate (lbs/hr)	Control Efficiency (%)	Controlled Emission Rates	
	Filterable	Condensable	Total				(lbs/hr)	(tons/yr)
PM ^[1]	0.34	-	0.34	20,000	3.35	90	0.34	1.47
PM ₁₀ ^[2]	0.28	-	0.28		2.85	90	0.28	1.25
PM _{2.5} ^[3]	0.10	-	0.10		1.01	90	0.10	0.44

^[1] PM filterable emission factors taken from AP-42 Table 9.9.1-2 for "Hammermill - Cyclone Control" and assumes 80% cyclone control efficiency = 0.067/(1-0.8)

^[2] PM₁₀ filterable is calculated as 85% of PM filterable, taken from EPA PM calculator based on SCC code 30203801 (Animal/Poultry Rendering - General:Uncontrolled).

^[3] PM_{2.5} filterable is calculated as 30% of PM filterable, taken from EPA PM calculator based on SCC code 30203801 (Animal/Poultry Rendering - General:Uncontrolled).

Cooker No. 1 - EU012

Pollutant	Emission Factors (lb/ton)			Process Capacity (lbs/hr)	Uncontrolled Emission Rate (lbs/hr)	Control Efficiency (%)	Controlled Emission Rates	
	Filterable	Condensable	Total				(lbs/hr)	(tons/yr)
PM ^[1]	0.56	0.24	0.80	25,000	10.00	90	1.00	4.38
PM ₁₀ ^[2]	0.48	0.24	0.72		8.95	90	0.90	3.92
PM _{2.5} ^[3]	0.17	0.24	0.41		5.10	90	0.51	2.23
VOC ^[4]	NA	NA	0.085		1.06	NA	1.06	4.66

^[1] PM filterable and condensable emission factors taken from AP-42 Table 9.13.3-2 for "Continuous Deep Fat Fryer - Other Snack Chips"

^[2] PM₁₀ filterable is calculated as 85% of PM filterable, taken from EPA PM calculator based on SCC code 30203803 (Animal/Poultry Rendering - Cooking:Uncontrolled). PM₁₀ condensable is 100% of PM condensable emission factor

^[3] PM_{2.5} filterable is calculated as 30% of PM filterable, taken from EPA PM calculator based on SCC code 30203803 (Animal/Poultry Rendering - Cooking:Uncontrolled). PM_{2.5} condensable is 100% of PM condensable emission factor

^[4] VOC emission factor from MPCA PTE records for GP003, dated January 8, 2013

Cooker No. 2 - EU013

Pollutant	Emission Factors (lb/ton)			Process Capacity (lbs/hr)	Uncontrolled Emission Rate (lbs/hr)	Control Efficiency (%)	Controlled Emission Rates	
	Filterable	Condensable	Total				(lbs/hr)	(tons/yr)
PM ^[1]	0.56	0.24	0.80	25,000	10.00	90	1.00	4.38
PM ₁₀ ^[2]	0.48	0.24	0.72		8.95	90	0.90	3.92
PM _{2.5} ^[3]	0.17	0.24	0.41		5.10	90	0.51	2.23
VOC ^[4]	NA	NA	0.085		1.06	NA	1.06	4.66

^[1] PM filterable and condensable emission factors taken from AP-42 Table 9.13.3-2 for "Continuous Deep Fat Fryer - Other Snack Chips"

^[2] PM₁₀ filterable is calculated as 85% of PM filterable, taken from EPA PM calculator based on SCC code 30203803 (Animal/Poultry Rendering - Cooking:Uncontrolled). PM₁₀ condensable is 100% of PM condensable emission factor

^[3] PM_{2.5} filterable is calculated as 30% of PM filterable, taken from EPA PM calculator based on SCC code 30203803 (Animal/Poultry Rendering - Cooking:Uncontrolled). PM_{2.5} condensable is 100% of PM condensable emission factor

^[4] VOC emission factor from MPCA PTE records for GP003, dated January 8, 2013

Total Controlled Cooking Process Emissions

Pollutant	Process Emission Rate (lbs/hr)	Maximum Unlimited (tons/yr)	Limited Potential (tons/yr)
PM	2.34	10.23	10.23
PM ₁₀	2.07	9.09	9.09
PM _{2.5}	1.12	4.91	4.91
VOIC	2.13	9.32	9.32

Sanimax
Feather Pneumatic Conveying System - EU014 (SV014)
PM, PM₁₀ and PM_{2.5} Emissions Calculations

Conveying

Pollutant	Emission Factors (lb/ton)			Process Capacity (lbs/hr)	Uncontrolled Emission Rate (lbs/hr)	Air Flow (dscfm)	Emission Factor ^[1] (gr/dscf)	Controlled Emission Rates		Control Efficiency (%)	Requested Control Efficiency (%)	Controlled Emission Rates	
	Filterable	Condensable	Total					(lbs/hr)	(tons/yr)			(lbs/hr)	(tons/yr)
PM ^[2]	-	-	0.72	2,500	0.90	240	0.002	0.004	0.018	99.5%	99%	0.009	0.039
PM ₁₀ ^[3]	-	-	0.46		0.58			0.004	0.018	99.3%	99%	0.006	0.025
PM _{2.5} ^[4]	-	-	0.46		0.58			0.004	0.018	99.3%	99%	0.006	0.025

^[1] See attached emission statement

^[2] PM emission factor taken from AP-42 Table 11.12-2 "Pneumatic Unloading of Cement to Elevated Storage Silo"

^[3] PM₁₀ emission factor taken from AP-42 Table 11.12-2 "Pneumatic Unloading of Cement to Elevated Storage Silo"

^[4] PM_{2.5} emissions factor is calculated as 100% of PM₁₀ as no AP-42 emission factor is available.

Sanimax
PPF Process - EU020, EU021 and EU022 (SV018)

PPF Cooking Process - EU020

Pollutant	Emission Factors (lb/ton)			Process Capacity (lbs/hr)	Uncontrolled Emission Rate (lbs/hr)	Control Efficiency (%)	Controlled Emission Rates	
	Filterable	Condensable	Total				(lbs/hr)	(tons/yr)
PM ^[1]	0.56	0.24	0.80	37,893	15.16	90	1.52	6.64
PM ₁₀ ^[2]	0.48	0.24	0.72		13.57	90	1.36	5.94
PM _{2.5} ^[3]	0.17	0.24	0.41		7.73	90	0.77	3.39
VOC ^[4]	-	-	0.09		1.61	90	0.16	0.71

^[1]PM filterable and condensable emission factors taken from AP-42 Table 9.13.3-2 for "Continuous Deep Fat Fryer - Other Snack Chips"

^[2] PM₁₀ filterable is calculated as 85% of PM filterable, taken from EPA PM calculator based on SCC code 30203803 (Animal/Poultry Rendering - Cooking:Uncontrolled). PM₁₀ condensable is 100% of PM condensable emission factor

^[3] PM_{2.5} filterable is calculated as 30% of PM filterable, taken from EPA PM calculator based on SCC code 30203803 (Animal/Poultry Rendering - Cooking:Uncontrolled). PM_{2.5} condensable is 100% of PM condensable emission factor

^[4]VOC emission factor taken from AP-42 Table 9.13.3-3 for "Continuous Deep Fat Fryer - Other Snack Chips"

PPF Pressing Process - EU021

Pollutant	Emission Factors (lb/ton)			Process Capacity (lbs/hr)	Uncontrolled Emission Rate (lbs/hr)	Control Efficiency (%)	Controlled Emission Rates	
	Filterable	Condensable	Total				(lbs/hr)	(tons/yr)
PM ^[1]	0.56	0.24	0.80	10,717	4.29	90	0.43	1.88
PM ₁₀ ^[2]	0.48	0.24	0.72		3.84	90	0.38	1.68
PM _{2.5} ^[3]	0.17	0.24	0.41		2.19	90	0.22	0.96
VOC ^[4]	-	-	0.09		0.46	90	0.05	0.20

^[1]PM filterable and condensable emission factors taken from AP-42 Table 9.13.3-2 for "Continuous Deep Fat Fryer - Other Snack Chips"

^[2] PM₁₀ filterable is calculated as 85% of PM filterable, taken from EPA PM calculator based on SCC code 30203801 (Animal/Poultry Rendering - General:Uncontrolled). PM₁₀ condensable is 100% of PM condensable emission factor

^[3] PM_{2.5} filterable is calculated as 30% of PM filterable, taken from EPA PM calculator based on SCC code 30203801 (Animal/Poultry Rendering - General:Uncontrolled). PM_{2.5} condensable is 100% of PM condensable emission factor

^[4]VOC emission factor taken from AP-42 Table 9.13.3-3 for "Continuous Deep Fat Fryer - Other Snack Chips"

PPF Milling Process - EU022

Pollutant	Emission Factors (lb/ton)			Process Capacity (lbs/hr)	Uncontrolled Emission Rate (lbs/hr)	Control Efficiency (%)	Controlled Emission Rates	
	Filterable	Condensable	Total				(lbs/hr)	(tons/yr)
PM ^[1]	0.34	-	0.34	9,860	1.65	90	0.17	0.72
PM ₁₀ ^[2]	0.28	-	0.28		1.40	90	0.14	0.61
PM _{2.5} ^[3]	0.10	-	0.10		0.50	90	0.05	0.22

^[1]PM filterable emission factors taken from AP-42 Table 9.9.1-2 for "Hammermill - Cyclone Control" and assumes 80% cyclone control efficiency = 0.067/(1-0.8)

^[2] PM₁₀ filterable is calculated as 85% of PM filterable, taken from EPA PM calculator based on SCC code 30203801 (Animal/Poultry Rendering - General:Uncontrolled)

^[3] PM_{2.5} filterable is calculated as 30% of PM filterable, taken from EPA PM calculator based on SCC code 30203801 (Animal/Poultry Rendering - General:Uncontrolled)

Total Controlled PPF Process Emissions

Pollutant	Process Emission Rate (lbs/hr)	Maximum Unlimited (tons/yr)	Limited Potential (tons/yr)
	(lbs/hr)	(tons/yr)	(tons/yr)
PM	2.11	9.24	9.24
PM ₁₀	1.88	8.24	8.24
PM _{2.5}	1.04	4.56	4.56
VOC	0.21	0.90	0.90

Sanimax											
Blood/Ring Dryer - EU002 (SV002)											
Combustion Emissions Calculations - EXISTING - (does not include process emissions)											
All Emission Factors from AP-42, unless otherwise noted.											
Capacity:	5 MMBtu/hr										
#2 Fuel Oil:	0.03571301	1000 gal/hr		#2 Fuel Oil Heating Value:		0.140005	MMBtu/gal		S (No. 2):	0.5	%
Natural Gas:	0.004901961	MMcf/hr		Natural Gas Heating Value:		1020	MMBtu/cf				
Item	Pollutant	#2 Oil Emission Factor (lb/1000 gal)	Natural Gas Emission Factor (lb/MMcf)	#2 Oil Hourly Potential (lb/hr)	Natural Gas Hourly Potential (lb/hr)	Worst Case Fuel Hourly Potential (lb/hr)	Unrestricted Potential (tpy)	Limited Potential (tpy)			
EU002 Dryer Fuels: Distillate (#2) Oil, Natural Gas	Acenaphthene	2.11E-05	1.80E-06	7.54E-07	8.82E-09	7.54E-07	3.30E-06	3.30E-06			
	Acenaphthylene	2.53E-07	1.80E-06	9.04E-09	8.82E-09	9.04E-09	3.96E-08	3.96E-08			
	Anthracene	1.22E-06	2.40E-06	4.36E-08	1.18E-08	4.36E-08	1.91E-07	1.91E-07			
	Benz(a)anthracene	4.01E-06	1.80E-06	1.43E-07	8.82E-09	1.43E-07	6.27E-07	6.27E-07			
	Benzene	2.14E-04	2.10E-03	7.64E-06	1.03E-05	1.03E-05	4.51E-05	4.51E-05			
	Benzo(a)pyrene		1.20E-06		5.88E-09	5.88E-09	2.58E-08	2.58E-08			
	Benzo(b)fluoranthene	1.48E-06	1.80E-06	5.29E-08	8.82E-09	5.29E-08	2.32E-07	2.32E-07			
	Benzo(g,h,i)perylene	2.26E-06	1.20E-06	8.07E-08	5.88E-09	8.07E-08	3.54E-07	3.54E-07			
	Benzo(k)fluoranthene	1.48E-06	1.80E-06	5.29E-08	8.82E-09	5.29E-08	2.32E-07	2.32E-07			
	Chrysene	2.38E-06	1.80E-06	8.50E-08	8.82E-09	8.50E-08	3.72E-07	3.72E-07			
	Dibenzo(a,h)anthracene	1.67E-06	1.20E-03	5.96E-08	5.88E-06	5.88E-06	2.58E-05	2.58E-05			
	Dichlorobenzene		1.20E-03		5.88E-06	5.88E-06	2.58E-05	2.58E-05			
	7,12-Dimethylbenz(a)anthracene		1.60E-05		7.84E-08	7.84E-08	3.44E-07	3.44E-07			
	Ethylbenzene	6.36E-05		2.27E-06		2.27E-06	9.95E-06	9.95E-06			
	Fluoranthene	4.84E-06	3.00E-06	1.73E-07	1.47E-08	1.73E-07	7.57E-07	7.57E-07			
	Fluorene	4.47E-06	2.80E-06	1.60E-07	1.37E-08	1.60E-07	6.99E-07	6.99E-07			
	Formaldehyde	3.30E-02	7.50E-02	1.18E-03	3.68E-04	1.18E-03	5.16E-03	5.16E-03			
	Hexane		1.80E+00	0.00E+00	8.82E-03	8.82E-03	3.86E-02	3.86E-02			
	Indeno(1,2,3-cd)pyrene	2.14E-06	1.80E-06	7.64E-08	8.82E-09	7.64E-08	3.35E-07	3.35E-07			
	2-Methylnaphthalene		2.40E-05		1.18E-07	1.18E-07	5.15E-07	5.15E-07			
	3-Methylchloranthrene		1.80E-06		8.82E-09	8.82E-09	3.86E-08	3.86E-08			
	Naphthalene	1.13E-03	6.10E-04	4.04E-05	2.99E-06	4.04E-05	1.77E-04	1.77E-04			
	Phenanthrene	1.05E-05	1.70E-05	3.75E-07	8.33E-08	3.75E-07	1.64E-06	1.64E-06			
	Phosphorus										
	Pyrene	4.25E-06		1.52E-07		1.52E-07	6.65E-07	6.65E-07			
	Toluene	6.20E-03	5.00E-06		2.45E-08	2.45E-08	1.07E-07	1.07E-07			
	1,1,1-Trichloroethane	2.36E-04		8.43E-06		8.43E-06	3.69E-05	3.69E-05			
	Xylenes	1.09E-04		3.89E-06		3.89E-06	1.71E-05	1.71E-05			
	Antimony compounds		5.25E-03		2.57E-05	2.57E-05	1.13E-04	1.13E-04			
	Arsenic compounds	5.60E-10	2.00E-04	2.00E-11	9.80E-07	9.80E-07	4.29E-06	4.29E-06			
	Beryllium compounds	4.20E-10	1.20E-05	1.50E-11	5.88E-08	5.88E-08	2.58E-07	2.58E-07			
	Cadmium compounds	4.20E-10	1.10E-03	1.50E-11	5.39E-06	5.39E-06	2.36E-05	2.36E-05			
	Chromium compounds	4.20E-10	1.40E-03	1.50E-11	6.86E-06	6.86E-06	3.01E-05	3.01E-05			
	Cobalt compounds		8.40E-05	0.00E+00	4.12E-07	4.12E-07	1.80E-06	1.80E-06			
	Manganese compounds	8.40E-10	3.80E-04	3.00E-11	1.86E-06	1.86E-06	8.16E-06	8.16E-06			
	Mercury compounds	4.20E-10	2.60E-04	1.50E-11	1.27E-06	1.27E-06	5.58E-06	5.58E-06			
	Nickel compounds	4.20E-10	2.10E-03	1.50E-11	1.03E-05	1.03E-05	4.51E-05	4.51E-05			
	Selenium compounds	2.10E-09	2.40E-05	7.50E-11	1.18E-07	1.18E-07	5.15E-07	5.15E-07			
	HAPs			0.00	0.01	0.01	0.04	0.04			
	Lead	1.26E-09	5.00E-04	4.50E-11	2.45E-06	2.45E-06	1.07E-05	1.07E-05			
	Total PM	2.00E+00	7.60E+00	7.14E-02	3.73E-02	0.07	0.31	0.31			
	PM ₁₀	1.00E+00	7.60E+00	3.57E-02	3.73E-02	0.04	0.16	0.16			
	PM _{2.5}	2.50E-01	7.60E+00	8.93E-03	3.73E-02	0.01	0.04	0.04			
	SO ₂	7.10E+01	6.00E-01	2.54E+00	2.94E-03	2.54	11.11	11.11			
	NOx	2.00E+01	1.00E+02	7.14E-01	4.90E-01	0.71	3.13	3.13			
	VOC	3.40E-01	5.50E+00	1.21E-02	2.70E-02	0.03	0.12	0.12			
	CO	5.00E+00	8.40E+01	1.79E-01	4.12E-01	0.41	1.80	1.80			
	CO ₂	2.23E+04	1.20E+05	7.96E+02	5.88E+02	796.40	3,488	3,488			
	CH ₄	5.20E-02	2.30E+00	1.86E-03	1.13E-02	0.01	0.05	0.05			
	N ₂ O	2.60E-01	2.20E+00	9.29E-03	1.08E-02	0.01	0.05	0.05			
	GHG			7.96E+02	5.88E+02	796.42	3,488	3,488			
	CO ₂ e			7.99E+02	5.92E+02	799.98	3,504	3,504			

Sanimax											
Boiler No. 2 - EU006 (SV006)											
Combustion Emissions Calculations - EXISTING											
All Emission Factors from AP-42, unless otherwise noted.											
Capacity:	17.58	MMBtu/hr									
#2 Fuel Oil:	0.125566944	1000 gal/hr			#2 Fuel Oil Heating Value:		0.140005	MMBtu/gal		S (No. 2):	0.5 %
Natural Gas:	0.017235294	MMcft/hr			Natural Gas Heating Value:		1020	MMBtu/cf			
Item	Pollutant	Natural Gas Emission Factor (lb/MMcf)	#2 Oil Emission Factor (lb/1000 gal)	Natural Gas Hourly Potential (lb/hr)	#2 Oil Hourly Potential (lb/hr)	Worst Case Emissions (lb/hr)	Unrestricted Potential (tpy)	Limited Potential (tpy)			
EU006 Boiler 2 Fuels: Distillate (#2) Fuel Oil, Natural Gas	Acenaphthene	1.80E-06	2.11E-05	3.10E-08	2.65E-06	2.65E-06	1.16E-05	1.16E-05			
	Acenaphthylene	1.80E-06	2.53E-07	3.10E-08	3.18E-08	3.18E-08	1.39E-07	1.39E-07			
	Anthracene	2.40E-06	1.22E-06	4.14E-08	1.53E-07	1.53E-07	6.71E-07	6.71E-07			
	benz(a)anthracene	1.80E-06	4.01E-06	3.10E-08	5.04E-07	5.04E-07	2.21E-06	2.21E-06			
	Benzene	2.10E-03	2.14E-04	3.62E-05	2.69E-05	3.62E-05	1.59E-04	1.59E-04			
	Benzo(a)pyrene	1.20E-06		2.07E-08		2.07E-08	9.06E-08	9.06E-08			
	Benzo(b)fluoranthene	1.80E-06	1.48E-06	3.10E-08	1.86E-07	1.86E-07	8.14E-07	8.14E-07			
	Benzo(g,h,i)perylene	1.20E-06	2.26E-06	2.07E-08	2.84E-07	2.84E-07	1.24E-06	1.24E-06			
	Benzo(k)fluoranthene	1.80E-06	1.48E-06	3.10E-08	1.86E-07	1.86E-07	8.14E-07	8.14E-07			
	Chrysene	1.80E-06	2.38E-06	3.10E-08	2.99E-07	2.99E-07	1.31E-06	1.31E-06			
	Dibenzo(a,h)anthracene	1.20E-03	1.67E-06	2.07E-05	2.10E-07	2.07E-05	9.06E-05	9.06E-05			
	Dichlorobenzene	1.20E-03		2.07E-05		2.07E-05	9.06E-05	9.06E-05			
	7,12-Dimethylbenz(a)anthracene	1.60E-05		2.76E-07		2.76E-07	1.21E-06	1.21E-06			
	Ethylbenzene		6.36E-05		7.99E-06	7.99E-06	3.50E-05	3.50E-05			
	Fluoranthene	3.00E-06	4.84E-06	5.17E-08	6.08E-07	6.08E-07	2.66E-06	2.66E-06			
	Fluorene	2.80E-06	4.47E-06	4.83E-08	5.61E-07	5.61E-07	2.46E-06	2.46E-06			
	Formaldehyde	7.50E-02	3.30E-02	1.29E-03	4.14E-03	4.14E-03	1.81E-02	1.81E-02			
	Hexane	1.80E+00		3.10E-02		3.10E-02	1.36E-01	1.36E-01			
	Indeno(1,2,3-cd)pyrene	1.80E-06	2.14E-06	3.10E-08	2.69E-07	2.69E-07	1.18E-06	1.18E-06			
	2-Methylnaphthalene	2.40E-05		4.14E-07		4.14E-07	1.81E-06	1.81E-06			
	3-Methylchloranthrene	1.80E-06		3.10E-08		3.10E-08	1.36E-07	1.36E-07			
	Naphthalene	6.10E-04	1.13E-03	1.05E-05	1.42E-04	1.42E-04	6.21E-04	6.21E-04			
	Phenanthrene	1.70E-05	1.05E-05	2.93E-07	1.32E-06	1.32E-06	5.77E-06	5.77E-06			
	Phosphorus										
	Pyrene	5.00E-06	4.25E-06	8.62E-08	5.34E-07	5.34E-07	2.34E-06	2.34E-06			
	Toluene	3.40E-03	6.20E-03	5.86E-05	7.79E-04	7.79E-04	3.41E-03	3.41E-03			
	1,1,1-Trichloroethane		2.36E-04		2.96E-05	2.96E-05	1.30E-04	1.30E-04			
	Xylenes		1.09E-04		1.37E-05	1.37E-05	5.99E-05	5.99E-05			
	Antimony compounds	5.25E-03		9.05E-05	0.00E+00	9.05E-05	3.96E-04	3.96E-04			
	Arsenic compounds	2.00E-04	5.60E-10	3.45E-06	7.03E-11	3.45E-06	1.51E-05	1.51E-05			
	Beryllium compounds	1.20E-05	4.20E-10	2.07E-07	5.27E-11	2.07E-07	9.06E-07	9.06E-07			
	Cadmium compounds	1.10E-03	4.20E-10	1.90E-05	5.27E-11	1.90E-05	8.30E-05	8.30E-05			
	Chromium compounds	1.40E-03	4.20E-10	2.41E-05	5.27E-11	2.41E-05	1.06E-04	1.06E-04			
	Cobalt compounds	8.40E-05		1.45E-06		1.45E-06	6.34E-06	6.34E-06			
	Manganese compounds	3.80E-04	8.40E-10	6.55E-06	1.05E-10	6.55E-06	2.87E-05	2.87E-05			
	Mercury compounds	2.60E-04	4.20E-10	4.48E-06	5.27E-11	4.48E-06	1.96E-05	1.96E-05			
	Nickel compounds	2.10E-03	4.20E-10	3.62E-05	5.27E-11	3.62E-05	1.59E-04	1.59E-04			
	Selenium compounds	2.40E-05	2.10E-09	4.14E-07	2.64E-10	4.14E-07	1.81E-06	1.81E-06			
	HAPs			0.03	0.01	0.03	0.14	0.14			
	Lead	5.00E-04	1.26E-09	8.62E-06	1.58E-10	8.62E-06	3.77E-05	3.77E-05			
	Total PM	7.60E+00	2.00E+00	1.31E-01	2.51E-01	0.25	1.10	1.10			
	PM ₁₀	7.60E+00	1.00E+00	1.31E-01	1.26E-01	0.13	0.57	0.57			
	PM _{2.5}	7.60E+00	2.50E-01	1.31E-01	3.14E-02	0.03	0.14	0.14			
	SO ₂	6.00E-01	7.10E+01	1.03E-02	8.92E+00	8.92	39.05	39.05			
	NOx	1.00E+02	2.00E+01	1.72E+00	2.51E+00	2.51	11.00	11.00			
	VOC	5.50E+00	2.00E-01	9.48E-02	2.51E-02	0.09	0.42	0.42			
	CO	8.40E+01	5.00E+00	1.45E+00	6.28E-01	1.45	6.34	6.34			
	CO ₂	1.20E+05	2.23E+04	2.07E+03	2.80E+03	2,800	12,265	12,265			
	CH ₄	2.30E+00	5.20E-02	3.96E-02	6.53E-03	0.04	0.17	0.17			
	N ₂ O	2.20E+00	2.60E-01	3.79E-02	3.26E-02	0.04	0.17	0.17			
	GHG			2.07E+03	2.80E+03	2,800	12,265	12,265			
	CO ₂ e			2.08E+03	2.81E+03	2,813	12,320	12,320			
	Existing PTE	lb/hr	tpy								
	CO ₂	12,528	54,874								
	CH ₄	0.39	1.71								
	N ₂ O	0.23	1.00								
	GHG	12,529	54,876								
	CO ₂ e	12,607	55,220								

Appendix C

Highlighted Copy of NSPS Subpart Dc

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR Data is current as of December 17, 2012

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Contents

- § 60.40c Applicability and delegation of authority.
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 - § 60.45c Compliance and performance test methods and procedures for particulate matter.
 - § 60.46c Emission monitoring for sulfur dioxide.
 - § 60.47c Emission monitoring for particulate matter.
 - § 60.48c Reporting and recordkeeping requirements.
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SOURCE: 72 FR 32759, June 13, 2007, unless otherwise noted.

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO₂) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

(e) Affected facilities (i.e. heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA

or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

(h) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_x standards under this subpart and the SO₂ standards under subpart J or subpart Ja of this part, as applicable.

(i) Temporary boilers are not subject to this subpart.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

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

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (*i.e.* , the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrosulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

Dry flue gas desulfurization technology means a SO₂ control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO₂ control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under § 60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO₂ emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

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

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

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

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

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO₂ emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

- (1) The equipment is attached to a foundation.
- (2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.
- (3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.
- (4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Wet flue gas desulfurization technology means an SO₂ control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO₂.

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

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

§ 60.42c Standard for sulfur dioxide (SO₂).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 87 ng/J (0.20

lb/MMBtu) heat input or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO₂ in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

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

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

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO₂ emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO₂ emissions limit or the 90 percent SO₂ reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO₂ emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 50 percent (0.50) of the potential SO₂ emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO₂ reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/h) or less;

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area; or

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be

completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO₂ in excess of the following:

(1) The percent of potential SO₂ emission rate or numerical SO₂ emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

- (i) Combusts coal in combination with any other fuel;
- (ii) Has a heat input capacity greater than 22 MW (75 MMBtu/h); and
- (iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

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

Where:

E_s = SO₂ emission limit, expressed in ng/J or lb/MMBtu heat input;

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

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

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

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

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

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

(f) Reduction in the potential SO₂ emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

- (1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO₂ emission rate; and
- (2) Emissions from the pretreated fuel (without either combustion or post-combustion SO₂ control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

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

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under § 60.48c(f), as applicable.

- (1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).
 - (2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).
 - (3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).
 - (4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).
- (i) The SO₂ emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.
- (j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9462, Feb. 16, 2012]

§ 60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and

operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under § 60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO₂ emissions is not subject to the PM limit in this section.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 77 FR 9462, Feb. 16, 2012]

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

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

(b) The initial performance test required under § 60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO₂ emission limits under § 60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) of this section and § 60.8,

compliance with the percent reduction requirements and SO₂ emission limits under § 60.42c is based on the average percent reduction and the average SO₂ emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO₂ emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO₂ emission rate (E_{ho}) and the 30-day average SO₂ emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B of appendix A of this part.

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

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

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

Where:

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

E_{ho} = Hourly SO₂ emission rate, ng/J (lb/MMBtu);

E_w = SO₂ concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w = 0$.

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

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

(f) Affected facilities subject to the percent reduction requirements under § 60.42c(a) or (b) shall determine compliance with the SO₂ emission limits under § 60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO₂ emission rate is computed using the following formula:

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

Where:

$\%P_s$ = Potential SO₂ emission rate, in percent;

$\%R_g$ = SO₂ removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$ = SO₂ removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in

paragraph (f)(1) of this section are used, except as provided for in the following:

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

$$\%R_{g\ o} = 100 \left(1 - \frac{E_{ao\ o}}{E_{ai\ o}} \right)$$

Where:

$\%R_{g\ o}$ = Adjusted $\%R_g$, in percent;

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

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

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

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

Where:

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

E_{hi} = Hourly SO_2 inlet rate, ng/J (lb/MMBtu);

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w = 0$; and

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

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under § 60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under § 60.46c(d)(2).

(h) For affected facilities subject to § 60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in § 60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under § 60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under § 60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating $\%P_s$ or E_{ho} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

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

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under § 60.43c shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B of appendix A-2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A-3 of this part or 17 of appendix A-6 of this part.

(3) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F).

(6) For determination of PM emissions, an oxygen (O₂) or carbon dioxide (CO₂) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O₂ or CO₂ measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(8) Method 9 of appendix A-4 of this part shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under § 60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated

24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) In place of PM testing with Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with § 60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under § 60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under § 60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (c)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (c)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under § 60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (c)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O₂ (or CO₂) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and

(ii) For O₂ (or CO₂), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in

accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.*, reference method) data and performance test (*i.e.*, compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/ert_tool.html/) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under § 60.43c(e)(4) shall follow the applicable procedures under § 60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

§ 60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO₂ emission limits under § 60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO₂ concentrations and either O₂ or CO₂ concentrations at the outlet of the SO₂ control device (or the outlet of the steam generating unit if no SO₂ control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under § 60.42c shall measure SO₂ concentrations and either O₂ or CO₂ concentrations at both the inlet and outlet of the SO₂ control device.

(b) The 1-hour average SO₂ emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.42c. Each 1-hour average SO₂ emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under § 60.13(h)(2). Hourly SO₂ emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

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

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

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

(3) For affected facilities subject to the percent reduction requirements under § 60.42c, the span value of the SO₂ CEMS at the inlet to the SO₂ control device shall be 125 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted, and the span value of the SO₂ CEMS at the outlet from the SO₂ control device shall be 50 percent of the maximum estimated hourly potential SO₂ emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of § 60.42c, the span value of the SO₂ CEMS at the outlet from the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) shall be 125 percent of the maximum estimated hourly potential

SO₂ emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO₂ emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO₂ control device (or outlet of the steam generating unit if no SO₂ control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO₂ emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO₂ input rate.

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

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO₂ at the inlet or outlet of the SO₂ control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO₂ and CO₂ measurement train operated at the candidate location and a second similar train operated according to the procedures in § 3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to § 60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO₂ standards based on fuel supplier certification, as described under § 60.48c(f), as applicable.

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

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c

shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in § 60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.*, 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.*, 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.*, 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in § 60.45c(a)(8).

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO₂ or PM emissions and that are subject to an opacity standard in § 60.43c(c) are not required to operate a COMS if they follow the applicable procedures in § 60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in § 60.45c(c). The CEMS specified in paragraph § 60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) Owners and operators of an affected facility that is subject to an opacity standard in § 60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO₂, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating

unit operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(4) You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(f) An owner or operator of an affected facility that is subject to an opacity standard in § 60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section § 60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section § 60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.48c(c).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by § 60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under § 60.42c, or § 60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO₂ emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO₂ emission limits of § 60.42c, or

the PM or opacity limits of § 60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator

(d) The owner or operator of each affected facility subject to the SO₂ emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO₂ emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO₂ emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO₂ emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO₂ or diluent (O₂ or CO₂) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of

average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in § 60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in § 60.48c(f) to demonstrate compliance with the SO₂ standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in § 60.42C to use fuel certification to demonstrate compliance with the SO₂ standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under § 60.42c or § 60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

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

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Appendix D

Highlighted Copy of NESHAP Subpart JJJJJJ

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR Data is current as of May 2, 2013

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES (CONTINUED)

Subpart JJJJJJ—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

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SOURCE: 76 FR 15591, Mar. 21, 2011, unless otherwise noted.

What This Subpart Covers

§ 63.11193 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler as defined in § 63.11237 that is located at, or is part of, an area source of hazardous air pollutants (HAP), as defined in § 63.2, except as specified in § 63.11195.

§ 63.11194 What is the affected source of this subpart?

(a) This subpart applies to each new, reconstructed, or existing affected source as defined in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers within a subcategory, as listed in § 63.11200 and defined in § 63.11237, located at an area source.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler within a subcategory, as listed in § 63.11200 and as defined in § 63.11237, located at an area source.

(b) An affected source is an existing source if you commenced construction or reconstruction of the affected source on or before June 4, 2010.

(c) An affected source is a new source if you commenced construction of the affected source after June 4, 2010, and the boiler meets the applicability criteria at the time you commence construction.

(d) An affected source is a reconstructed source if the boiler meets the reconstruction criteria as defined in § 63.2, you commenced reconstruction after June 4, 2010, and the boiler meets the applicability criteria at the time you commence reconstruction.

(e) An existing dual-fuel fired boiler meeting the definition of gas-fired boiler, as defined in § 63.11237, that meets the applicability requirements of this subpart after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be an existing source under this subpart as long as the boiler was designed to accommodate the alternate fuel.

(f) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or part 71 as a result of this subpart. You may, however, be required to obtain a title V permit due to another reason or reasons. See 40 CFR 70.3(a) and (b) or 71.3(a) and (b). Notwithstanding the exemption from title V permitting for area sources under this subpart, you must continue to comply with the provisions of this subpart.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7506, Feb. 1, 2013]

§ 63.11195 Are any boilers not subject to this subpart?

The types of boilers listed in paragraphs (a) through (k) of this section are not subject to this subpart and to any requirements in this subpart.

(a) Any boiler specifically listed as, or included in the definition of, an affected source in another standard(s) under this part.

(b) Any boiler specifically listed as an affected source in another standard(s) established under section 129 of the Clean Air Act.

(c) A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (e.g., hazardous waste boilers), unless such units do not combust hazardous waste and combust comparable fuels.

(d) A boiler that is used specifically for research and development. This exemption does not include boilers that solely or primarily provide steam (or heat) to a process or for heating at a research and development facility. This exemption does not prohibit the use of the steam (or heat) generated from the boiler during research and development, however, the boiler must be concurrently and primarily engaged in research and development for the exemption to apply.

(e) A gas-fired boiler as defined in this subpart.

(f) A hot water heater as defined in this subpart.

(g) Any boiler that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler is provided by regulated gas streams that are subject to another standard.

(h) Temporary boilers as defined in this subpart.

(i) Residential boilers as defined in this subpart.

(j) Electric boilers as defined in this subpart.

(k) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7506, Feb. 1, 2013]

§ 63.11196 What are my compliance dates?

(a) If you own or operate an existing affected boiler, you must achieve compliance with the applicable provisions in this subpart as specified in paragraphs (a)(1) through (3) of this section.

(1) If the existing affected boiler is subject to a work practice or management practice standard of a tune-up, you must achieve compliance with the work practice or management practice standard no later than March 21, 2014.

(2) If the existing affected boiler is subject to emission limits, you must achieve compliance with the emission limits no later than March 21, 2014.

(3) If the existing affected boiler is subject to the energy assessment requirement, you must achieve compliance with the energy assessment requirement no later than March 21, 2014.

(b) If you start up a new affected source on or before May 20, 2011, you must achieve compliance with the provisions of this subpart no later than May 20, 2011.

(c) If you start up a new affected source after May 20, 2011, you must achieve compliance with the provisions of this subpart upon startup of your affected source.

(d) If you own or operate an industrial, commercial, or institutional boiler and would be subject to this subpart except for the exemption in § 63.11195(b) for commercial and industrial solid waste incineration units covered by 40 CFR part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the waste to fuel switch as specified in § 60.2145(a)(2) and (3) of subpart CCCC or § 60.2710(a)(2) and (3) of subpart DDDD.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7506, Feb. 1, 2013]

Emission Limits, Work Practice Standards, Emission Reduction Measures, and Management Practices

§ 63.11200 What are the subcategories of boilers?

The subcategories of boilers, as defined in § 63.11237 are:

(a) Coal.

(b) Biomass.

(c) Oil.

(d) Seasonal boilers.

(e) Oil-fired boilers with heat input capacity of equal to or less than 5 million British thermal units (Btu) per hour.

(f) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up.

(g) Limited-use boilers.

[78 FR 7506, Feb. 1, 2013]

§ 63.11201 What standards must I meet?

(a) You must comply with each emission limit specified in Table 1 to this subpart that applies to your boiler.

(b) You must comply with each work practice standard, emission reduction measure, and management practice specified in Table 2 to this subpart that applies to your boiler. An energy assessment completed on or after January 1, 2008 that meets or is amended to meet the energy assessment requirements in Table 2 to this subpart satisfies the energy assessment requirement. A facility that operates under an energy management program established through energy management systems compatible with ISO 50001, that includes the affected units, also satisfies the energy

assessment requirement.

(c) You must comply with each operating limit specified in Table 3 to this subpart that applies to your boiler.

(d) These standards apply at all times the affected boiler is operating, except during periods of startup and shutdown as defined in § 63.11237, during which time you must comply only with Table 2 to this subpart.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7506, Feb. 1, 2013]

General Compliance Requirements

§ 63.11205 What are my general requirements for complying with this subpart?

(a) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or a continuous monitoring system (CMS), including a continuous emission monitoring system (CEMS), a continuous opacity monitoring system (COMS), or a continuous parameter monitoring system (CPMS), where applicable. You may demonstrate compliance with the applicable mercury emission limit using fuel analysis if the emission rate calculated according to § 63.11211(c) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using stack testing.

(c) If you demonstrate compliance with any applicable emission limit through performance stack testing and subsequent compliance with operating limits (including the use of CPMS), with a CEMS, or with a COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (c)(1) through (3) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses paragraphs (c)(1)(i) through (vi) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of § 63.11224.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations).

(iv) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(v) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(vi) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c) (as applicable in Table 8 to this subpart), (e)(1), and (e)(2)(i).

(2) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(3) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7506, Feb. 1, 2013]

Initial Compliance Requirements

§ 63.11210 What are my initial compliance requirements and by what date must I conduct them?

(a) You must demonstrate initial compliance with each emission limit specified in Table 1 to this subpart that applies to you by either conducting performance (stack) tests, as applicable, according to § 63.11212 and Table 4 to this subpart or, for mercury, conducting fuel analyses, as applicable, according to § 63.11213 and Table 5 to this subpart.

(b) For existing affected boilers that have applicable emission limits, you must demonstrate initial compliance with the applicable emission limits no later than 180 days after the compliance date that is specified in § 63.11196 and according to the applicable provisions in § 63.7(a)(2), except as provided in paragraph (j) of this section.

(c) For existing affected boilers that have applicable work practice standards, management practices, or emission reduction measures, you must demonstrate initial compliance no later than the compliance date that is specified in § 63.11196 and according to the applicable provisions in § 63.7(a)(2), except as provided in paragraph (j) of this section.

(d) For new or reconstructed affected boilers that have applicable emission limits, you must demonstrate initial compliance with the applicable emission limits no later than 180 days after March 21, 2011 or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(e) For new or reconstructed oil-fired boilers that combust only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM emission limit under this subpart and that do not use a post-combustion technology (except a wet scrubber) to reduce particulate matter (PM) or sulfur dioxide emissions, you are not subject to the PM emission limit in Table 1 of this subpart providing you monitor and record on a monthly basis the type of fuel combusted. If you intend to burn a new type of fuel or fuel mixture that does not meet the requirements of this paragraph, you must conduct a performance test within 60 days of burning the new fuel.

(f) For new or reconstructed affected boilers that have applicable work practice standards or management practices, you are not required to complete an initial performance tune-up, but you are required to complete the applicable biennial or 5-year tune-up as specified in § 63.11223 no later than 25 months or 61 months, respectively, after the initial startup of the new or reconstructed affected source.

(g) For affected boilers that ceased burning solid waste consistent with § 63.11196(d) and for which your initial compliance date has passed, you must demonstrate compliance within 60 days of the

effective date of the waste-to-fuel switch as specified in § 60.2145(a)(2) and (3) of subpart CCCC or § 60.2710(a)(2) and (3) of subpart DDDD. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(h) For affected boilers that switch fuels or make a physical change to the boiler that results in the applicability of a different subcategory within subpart JJJJJJ or the boiler becoming subject to subpart JJJJJJ, you must demonstrate compliance within 180 days of the effective date of the fuel switch or the physical change. Notification of such changes must be submitted according to § 63.11225(g).

(i) For boilers located at existing major sources of HAP that limit their potential to emit (e.g., make a physical change or take a permit limit) such that the existing major source becomes an area source, you must comply with the applicable provisions as specified in paragraphs (i)(1) through (3) of this section.

(1) Any such existing boiler at the existing source must demonstrate compliance with subpart JJJJJJ within 180 days of the later of March 21, 2014 or upon the existing major source commencing operation as an area source.

(2) Any new or reconstructed boiler at the existing source must demonstrate compliance with subpart JJJJJJ within 180 days of the later of March 21, 2011 or startup.

(3) Notification of such changes must be submitted according to § 63.11225(g).

(j) For existing affected boilers that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.11196, you must comply with the applicable provisions as specified in paragraphs (j)(1) through (3) of this section.

(1) You must complete the initial compliance demonstration, if subject to the emission limits in Table 1 to this subpart, as specified in paragraphs (a) and (b) of this section, no later than 180 days after the re-start of the affected boiler and according to the applicable provisions in § 63.7(a)(2).

(2) You must complete the initial performance tune-up, if subject to the tune-up requirements in § 63.11223, by following the procedures described in § 63.11223(b) no later than 30 days after the re-start of the affected boiler.

(3) You must complete the one-time energy assessment, if subject to the energy assessment requirements specified in Table 2 to this subpart, no later than the compliance date specified in § 63.11196.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7507, Feb. 1, 2013]

§ 63.11211 How do I demonstrate initial compliance with the emission limits?

(a) For affected boilers that demonstrate compliance with any of the emission limits of this subpart through performance (stack) testing, your initial compliance requirements include conducting performance tests according to § 63.11212 and Table 4 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler according to § 63.11213 and Table 5 to this subpart, establishing operating limits according to § 63.11222, Table 6 to this subpart and paragraph (b) of this section, as applicable, and conducting CMS performance evaluations according to § 63.11224. For affected boilers that burn a single type of fuel, you are exempted from the compliance requirements of conducting a fuel analysis for each type of fuel burned in your boiler. For purposes of this subpart, boilers that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected boilers that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.11213 and Table 5 to this subpart.

(b) You must establish parameter operating limits according to paragraphs (b)(1) through (4) of this

section.

(1) For a wet scrubber, you must establish the minimum scrubber liquid flow rate and minimum scrubber pressure drop as defined in § 63.11237, as your operating limits during the three-run performance stack test. If you use a wet scrubber and you conduct separate performance stack tests for PM and mercury emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. If you conduct multiple performance stack tests, you must set the minimum scrubber liquid flow rate and pressure drop operating limits at the highest minimum values established during the performance stack tests.

(2) For an electrostatic precipitator operated with a wet scrubber, you must establish the minimum total secondary electric power (secondary voltage and secondary current), as defined in § 63.11237, as your operating limits during the three-run performance stack test.

(3) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.11237, as your operating limit during the three-run performance stack test.

(4) The operating limit for boilers with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.11224, and that each fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period.

(c) If you elect to demonstrate compliance with an applicable mercury emission limit through fuel analysis, you must conduct fuel analyses according to § 63.11213 and Table 5 to this subpart and follow the procedures in paragraphs (c)(1) through (3) of this section.

(1) If you burn more than one fuel type, you must determine the fuel type, or mixture, you could burn in your boiler that would result in the maximum emission rates of mercury.

(2) You must determine the 90th percentile confidence level fuel mercury concentration of the composite samples analyzed for each fuel type using Equation 1 of this section.

$$P_{90} = \text{mean} + (\text{SD} * t) \quad (\text{Eq. 1})$$

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Where:

P_{90} = 90th percentile confidence level mercury concentration, in pounds per million Btu.

mean = Arithmetic average of the fuel mercury concentration in the fuel samples analyzed according to § 63.11213, in units of pounds per million Btu.

SD = Standard deviation of the mercury concentration in the fuel samples analyzed according to § 63.11213, in units of pounds per million Btu.

t = t distribution critical value for 90th percentile (0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable mercury emission limit, the emission rate that you calculate for your boiler using Equation 1 of this section must be less than the applicable mercury emission limit.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7508, Feb. 1, 2013]

§ 63.11212 What stack tests and procedures must I use for the performance tests?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also

develop a site-specific test plan according to the requirements in § 63.7(c).

(b) You must conduct each stack test according to the requirements in Table 4 to this subpart.

Boilers that use a CEMS for carbon monoxide (CO) are exempt from the initial CO performance testing in Table 4 to this subpart and the oxygen concentration operating limit requirement specified in Table 3 to this subpart.

(c) You must conduct performance stack tests at the representative operating load conditions while burning the type of fuel or mixture of fuels that have the highest emissions potential for each regulated pollutant, and you must demonstrate initial compliance and establish your operating limits based on these performance stack tests. For subcategories with more than one emission limit, these requirements could result in the need to conduct more than one performance stack test. Following each performance stack test and until the next performance stack test, you must comply with the operating limit for operating load conditions specified in Table 3 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance stack test required in this section, as specified in § 63.7(e)(3) and in accordance with the provisions in Table 4 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 of appendix A-7 to part 60 of this chapter to convert the measured PM concentrations and the measured mercury concentrations that result from the performance test to pounds per million Btu heat input emission rates.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7508, Feb. 1, 2013]

§ 63.11213 What fuel analyses and procedures must I use for the performance tests?

(a) You must conduct fuel analyses according to the procedures in paragraphs (b) and (c) of this section and Table 5 to this subpart, as applicable. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury in Table 1 of this subpart.

(b) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in Table 5 to this subpart. Each composite sample must consist of a minimum of three samples collected at approximately equal intervals during a test run period.

(c) Determine the concentration of mercury in the fuel in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 5 to this subpart.

§ 63.11214 How do I demonstrate initial compliance with the work practice standard, emission reduction measures, and management practice?

(a) If you own or operate an existing or new coal-fired boiler with a heat input capacity of less than 10 million Btu per hour, you must conduct a performance tune-up according to § 63.11223(b) and you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the boiler.

(b) If you own or operate an existing or new biomass-fired boiler or an existing or new oil-fired boiler, you must conduct a performance tune-up according to § 63.11223(b) and you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the boiler.

(c) If you own or operate an existing affected boiler with a heat input capacity of 10 million Btu per hour or greater, you must submit a signed certification in the Notification of Compliance Status report

that an energy assessment of the boiler and its energy use systems was completed according to Table 2 to this subpart and is an accurate depiction of your facility.

(d) If you own or operate a boiler subject to emission limits in Table 1 of this subpart, you 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, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7508, Feb. 1, 2013]

Continuous Compliance Requirements

§ 63.11220 When must I conduct subsequent performance tests or fuel analyses?

(a) If your boiler has a heat input capacity of 10 million British thermal units per hour or greater, you must conduct all applicable performance (stack) tests according to § 63.11212 on a triennial basis, except as specified in paragraphs (b) through (d) of this section. Triennial performance tests must be completed no more than 37 months after the previous performance test.

(b) When demonstrating initial compliance with the PM emission limit, if your boiler's performance test results show that your PM emissions are equal to or less than half of the PM emission limit, you do not need to conduct further performance tests for PM but must continue to comply with all applicable operating limits and monitoring requirements. If your initial performance test results show that your PM emissions are greater than half of the PM emission limit, you must conduct subsequent performance tests as specified in paragraph (a) of this section.

(c) If you demonstrate compliance with the mercury emission limit based on fuel analysis, you must conduct a fuel analysis according to § 63.11213 for each type of fuel burned as specified in paragraphs (c)(1) and (2) of this section. If you plan to burn a new type of fuel or fuel mixture, you must conduct a fuel analysis before burning the new type of fuel or mixture in your boiler. You must recalculate the mercury emission rate using Equation 1 of § 63.11211. The recalculated mercury emission rate must be less than the applicable emission limit.

(1) When demonstrating initial compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are measured to be equal to or less than half of the mercury emission limit, you do not need to conduct further fuel analysis sampling but must continue to comply with all applicable operating limits and monitoring requirements.

(2) When demonstrating initial compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are greater than half of the mercury emission limit, you must conduct quarterly sampling.

(d) For existing affected boilers that have not operated since the previous compliance demonstration and more than 3 years have passed since the previous compliance demonstration, you must complete your subsequent compliance demonstration no later than 180 days after the re-start of the affected boiler.

[78 FR 7508, Feb. 1, 2013]

§ 63.11221 Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan

required by § 63.11205(c).

(b) You must operate the monitoring system and collect data at all required intervals at all times the affected source is operating and compliance is required, except for periods of monitoring system malfunctions or out-of-control periods (see § 63.8(c)(7) of this part), repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data collected during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or quality control activities in calculations used to report emissions or operating levels. Any such periods must be reported according to the requirements in § 63.11225. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan), failure to collect required data is a deviation of the monitoring requirements.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7508, Feb. 1, 2013]

§ 63.11222 How do I demonstrate continuous compliance with the emission limits?

(a) You must demonstrate continuous compliance with each emission limit and operating limit in Tables 1 and 3 to this subpart that applies to you according to the methods specified in Table 7 to this subpart and to paragraphs (a)(1) through (4) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.11196, whichever date comes first, you must continuously monitor the operating parameters. Operation above the established maximum, below the established minimum, or outside the allowable range of the operating limits specified in paragraph (a) of this section constitutes a deviation from your operating limits established under this subpart, except during performance tests conducted to determine compliance with the emission and operating limits or to establish new operating limits. Operating limits are confirmed or reestablished during performance tests.

(2) If you have an applicable mercury or PM emission limit, you must keep records of the type and amount of all fuels burned in each boiler during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in lower emissions of mercury than the applicable emission limit (if you demonstrate compliance through fuel analysis), or result in lower fuel input of mercury than the maximum values calculated during the last performance stack test (if you demonstrate compliance through performance stack testing).

(3) If you have an applicable mercury emission limit and you plan to burn a new type of fuel, you must determine the mercury concentration for any new fuel type in units of pounds per million Btu, using the procedures in Equation 1 of § 63.11211 based on supplier data or your own fuel analysis, and meet the requirements in paragraphs (a)(3)(i) or (ii) of this section.

(i) The recalculated mercury emission rate must be less than the applicable emission limit.

(ii) If the mercury concentration is higher than mercury fuel input during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.11212 to demonstrate that the mercury emissions do not exceed the emission limit.

(4) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alarm and operate and maintain the fabric filter system such that the alarm does not sound more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm is counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time is counted as the actual amount of time taken to initiate corrective action.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 and 3 to this subpart that apply to you. These instances are deviations from the emission limits in this subpart. These deviations must be reported according to the requirements in § 63.11225.

§ 63.11223 How do I demonstrate continuous compliance with the work practice and management practice standards?

(a) For affected sources subject to the work practice standard or the management practices of a tune-up, you must conduct a performance tune-up according to paragraph (b) of this section and keep records as required in § 63.11225(c) to demonstrate continuous compliance. You must conduct the tune-up while burning the type of fuel (or fuels in the case of boilers that routinely burn two types of fuels at the same time) that provided the majority of the heat input to the boiler over the 12 months prior to the tune-up.

(b) Except as specified in paragraphs (c) through (f) of this section, you must conduct a tune-up of the boiler biennially to demonstrate continuous compliance as specified in paragraphs (b)(1) through (7) of this section. Each biennial tune-up must be conducted no more than 25 months after the previous tune-up. For a new or reconstructed boiler, the first biennial tune-up must be no later than 25 months after the initial startup of the new or reconstructed boiler.

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection.

(2) 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.

(3) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection.

(4) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any nitrogen oxide requirement to which the unit is subject.

(5) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer.

(6) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (b)(6)(i) through (iii) of this section.

(i) The concentrations of CO in the effluent stream in parts per million, by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler.

(ii) A description of any corrective actions taken as a part of the tune-up of the boiler.

(iii) The type and amount of fuel used over the 12 months prior to the tune-up of the boiler, 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) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 days of startup.

(c) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up must conduct a tune-up of the boiler every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed boiler with an oxygen trim system, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months.

(d) Seasonal boilers must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed seasonal boiler, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months. Seasonal boilers are not subject to the emission limits in Table 1 to this subpart or the operating limits in Table 3 to this subpart.

(e) Oil-fired boilers with a heat input capacity of equal to or less than 5 million Btu per hour must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed oil-fired boiler with a heat input capacity of equal to or less than 5 million Btu per hour, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months.

(f) Limited-use boilers must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed limited-use boiler, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months. Limited-use boilers are not subject to the emission limits in Table 1 to this subpart, the energy assessment requirements in Table 2 to this subpart,

or the operating limits in Table 3 to this subpart.

(g) If you own or operate a boiler subject to emission limits in Table 1 of this subpart, you 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, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7509, Feb. 1, 2013]

§ 63.11224 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler is subject to a CO emission limit in Table 1 to this subpart, you must either install, operate, and maintain a CEMS for CO and oxygen according to the procedures in paragraphs (a)(1) through (6) of this section, or install, calibrate, operate, and maintain an oxygen analyzer system, as defined in § 63.11237, according to the manufacturer's recommendations and paragraphs (a)(7) and (d) of this section, as applicable, by the compliance date specified in § 63.11196. Where a certified CO CEMS is used, the CO level shall be monitored at the outlet of the boiler, after any add-on controls or flue gas recirculation system and before release to the atmosphere. Boilers that use a CO CEMS are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in § 63.11211(a) of this subpart. Oxygen monitors and oxygen trim systems must be installed to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location.

(1) Each CO CEMS must be installed, operated, and maintained according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, and each oxygen CEMS must be installed, operated, and maintained according to Performance Specification 3 at 40 CFR part 60, appendix B. Both the CO and oxygen CEMS must also be installed, operated, and maintained according to the site-specific monitoring plan developed according to paragraph (c) of this section.

(2) You must conduct a performance evaluation of each CEMS according to the requirements in § 63.8(e) and according to Performance Specifications 3 and 4, 4A, or 4B at 40 CFR part 60, appendix B.

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) every 15 minutes. You must have CEMS data values from a minimum of four successive cycles of operation representing each of the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2).

(5) You must calculate hourly averages, corrected to 3 percent oxygen, from each hour of CO CEMS data in parts per million CO concentrations and determine the 10-day rolling average of all recorded readings, except as provided in § 63.11221(c). Calculate a 10-day rolling average from all of the hourly averages collected for the 10-day operating period using Equation 2 of this section.

$$\text{10-day average} = \frac{\sum_{i=1}^n H_{pvi}}{n} \quad (\text{Eq. 2})$$

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Where:

H_{pvi} = the hourly parameter value for hour *i*

n = the number of valid hourly parameter values collected over 10 boiler operating days

(6) For purposes of collecting CO data, you must operate the CO CEMS as specified in § 63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in § 63.11221(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in § 63.11221(d).

(7) You must operate the oxygen analyzer system at or above the minimum oxygen level that is established as the operating limit according to Table 6 to this subpart when firing the fuel or fuel mixture utilized during the most recent CO performance stack test. Operation of oxygen trim systems to meet these requirements shall not be done in a manner which compromises furnace safety.

(b) If you are using a control device to comply with the emission limits specified in Table 1 to this subpart, you must maintain each operating limit in Table 3 to this subpart that applies to your boiler as specified in Table 7 to this subpart. If you use a control device not covered in Table 3 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the United States Environmental Protection Agency (EPA) Administrator for approval of alternative monitoring under § 63.8(f).

(c) If you demonstrate compliance with any applicable emission limit through stack testing and subsequent compliance with operating limits, you must develop a site-specific monitoring plan according to the requirements in paragraphs (c)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section, you must develop, and submit to the EPA Administrator for approval upon request, a site-specific monitoring plan that addresses paragraphs (c)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan (if requested) at least 60 days before your initial performance evaluation of your CMS.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected unit such that the measurement is representative of control of the exhaust emissions (*e.g.*, on or downstream of the last control device).

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(iii) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations).

(2) In your site-specific monitoring plan, you must also address paragraphs (c)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1), (3), and (4)(ii).

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d).

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific

monitoring plan.

(d) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each CPMS according to the procedures in paragraphs (d)(1) through (4) of this section.

(1) The CPMS must complete a minimum of one cycle of operation every 15 minutes. You must have data values from a minimum of four successive cycles of operation representing each of the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed, to have a valid hour of data.

(2) You must calculate hourly arithmetic averages from each hour of CPMS data in units of the operating limit and determine the 30-day rolling average of all recorded readings, except as provided in § 63.11221(c). Calculate a 30-day rolling average from all of the hourly averages collected for the 30-day operating period using Equation 3 of this section.

$$\text{30-day average} = \frac{\sum_{i=1}^n Hpvi}{n} \quad (\text{Eq. 3})$$

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Where:

Hpvi = the hourly parameter value for hour i

n = the number of valid hourly parameter values collected over 30 boiler operating days

(3) For purposes of collecting data, you must operate the CPMS as specified in § 63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in § 63.11221(c). Periods when CPMS data are unavailable may constitute monitoring deviations as specified in § 63.11221(d).

(4) Record the results of each inspection, calibration, and validation check.

(e) If you have an applicable opacity operating limit under this rule, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (e)(1) through (8) of this section by the compliance date specified in § 63.11196.

(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 of 40 CFR part 60, appendix B.

(2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8 and according to Performance Specification 1 of 40 CFR part 60, appendix B.

(3) As specified in § 63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in § 63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in § 63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit,

or an annual zero alignment audit.

(7) You must calculate and record 6-minute averages from the opacity monitoring data and determine and record the daily block average of recorded readings, except as provided in § 63.11221(c).

(8) For purposes of collecting opacity data, you must operate the COMS as specified in § 63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in § 63.11221(c). Periods when COMS data are unavailable may constitute monitoring deviations as specified in § 63.11221(d).

(f) If you use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (f)(1) through (8) of this section.

(1) You must install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(2) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with EPA-454/R-98-015 (incorporated by reference, see § 63.14).

(3) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(5) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.

(6) The bag leak detection system must be equipped with an audible or visual alarm system that will activate automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard or seen by plant operating personnel.

(7) For positive pressure fabric filter systems that do not duct all compartments or cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

(8) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7510, Feb. 1, 2013]

§ 63.11225 What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications specified in paragraphs (a)(1) through (5) of this section to the administrator.

(1) You must submit all of the notifications in §§ 63.7(b); 63.8(e) and (f); and 63.9(b) through (e), (g), and (h) that apply to you by the dates specified in those sections except as specified in paragraphs (a)(2) and (4) of this section.

(2) An Initial Notification must be submitted no later than January 20, 2014 or within 120 days after the source becomes subject to the standard.

(3) If you are required to conduct a performance stack test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance stack test is scheduled to begin.

(4) You must submit the Notification of Compliance Status no later than 120 days after the applicable compliance date specified in § 63.11196 unless you must conduct a performance stack test. If you must conduct a performance stack test, you must submit the Notification of Compliance Status within 60 days of completing the performance stack test. You must submit the Notification of Compliance Status in accordance with paragraphs (a)(4)(i) and (vi) of this section. The Notification of Compliance Status must include the information and certification(s) of compliance in paragraphs (a)(4)(i) through (v) of this section, as applicable, and signed by a responsible official.

(i) You must submit the information required in § 63.9(h)(2), except the information listed in § 63.9(h)(2)(i)(B), (D), (E), and (F). If you conduct any performance tests or CMS performance evaluations, you must submit that data as specified in paragraph (e) of this section. If you conduct any opacity or visible emission observations, or other monitoring procedures or methods, you must submit that data to the Administrator at the appropriate address listed in § 63.13.

(ii) "This facility complies with the requirements in § 63.11214 to conduct an initial tune-up of the boiler."

(iii) "This facility has had an energy assessment performed according to § 63.11214(c)."

(iv) For units that install bag leak detection systems: "This facility complies with the requirements in § 63.11224(f)."

(v) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: "No secondary materials that are solid waste were combusted in any affected unit."

(vi) The notification must be submitted electronically using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written Notification of Compliance Status must be submitted to the Administrator at the appropriate address listed in § 63.13.

(5) If you are using data from a previously conducted emission test to serve as documentation of conformance with the emission standards and operating limits of this subpart, you must include in the Notification of Compliance Status the date of the test and a summary of the results, not a complete test report, relative to this subpart.

(b) You must prepare, by March 1 of each year, and submit to the delegated authority upon request, an annual compliance certification report for the previous calendar year containing the information specified in paragraphs (b)(1) through (4) of this section. You must submit the report by March 15 if you had any instance described by paragraph (b)(3) of this section. For boilers that are subject only to a requirement to conduct a biennial or 5-year tune-up according to § 63.11223(a) and not subject to emission limits or operating limits, you may prepare only a biennial or 5-year compliance report as specified in paragraphs (b)(1) and (2) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with the official's name, title, phone number, email address, and signature, certifying the truth, accuracy and completeness of the notification and a statement of whether the source has complied with all the relevant standards and other requirements of this subpart. Your notification must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility complies with the requirements in § 63.11223 to conduct a biennial or 5-year tune-up, as applicable, of each boiler."

(ii) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: “No secondary materials that are solid waste were combusted in any affected unit.”

(iii) “This facility complies with the requirement in §§ 63.11214(d) and 63.11223(g) to minimize the boiler's time spent during startup and shutdown and to conduct startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available.”

(3) If the source experiences any deviations from the applicable requirements during the reporting period, include a description of deviations, the time periods during which the deviations occurred, and the corrective actions taken.

(4) The total fuel use by each affected boiler subject to an emission limit, for each calendar month within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by you or EPA through a petition process to be a non-waste under § 241.3(c), whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of § 241.3, and the total fuel usage amount with units of measure.

(c) You must maintain the records specified in paragraphs (c)(1) through (7) of this section.

(1) As required in § 63.10(b)(2)(xiv), you must keep a copy of each notification and report that you submitted to comply with this subpart and all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted.

(2) You must keep records to document conformance with the work practices, emission reduction measures, and management practices required by § 63.11214 and § 63.11223 as specified in paragraphs (c)(2)(i) through (vi) of this section.

(i) Records must identify each boiler, the date of tune-up, the procedures followed for tune-up, and the manufacturer's specifications to which the boiler was tuned.

(ii) For operating units that combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) of this chapter, you must keep a record which documents how the secondary material meets each of the legitimacy criteria under § 241.3(d)(1). If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfies the definition of processing in § 241.2 and each of the legitimacy criteria in § 241.3(d)(1) of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per § 241.4, you must keep records documenting that the material is a listed non-waste under § 241.4(a).

(iii) For each boiler required to conduct an energy assessment, you must keep a copy of the energy assessment report.

(iv) For each boiler subject to an emission limit in Table 1 to this subpart, you must also keep records of monthly fuel use by each boiler, including the type(s) of fuel and amount(s) used.

(v) For each boiler that meets the definition of seasonal boiler, you must keep records of days of operation per year.

(vi) For each boiler that meets the definition of limited-use boiler, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and records of fuel use for the days the boiler is operating.

(3) For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation that were done to demonstrate compliance with the mercury emission limits. Supporting documentation should include results of any fuel analyses. You can use the results from one fuel analysis for multiple boilers provided they are all burning the same fuel type.

(4) Records of the occurrence and duration of each malfunction of the boiler, or of the associated air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in § 63.11205(a), including corrective actions to restore the malfunctioning boiler, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(6) You must keep the records of all inspection and monitoring data required by §§ 63.11221 and 63.11222, and the information identified in paragraphs (c)(6)(i) through (vi) of this section for each required inspection or monitoring.

(i) The date, place, and time of the monitoring event.

(ii) Person conducting the monitoring.

(iii) Technique or method used.

(iv) Operating conditions during the activity.

(v) Results, including the date, time, and duration of the period from the time the monitoring indicated a problem to the time that monitoring indicated proper operation.

(vi) Maintenance or corrective action taken (if applicable).

(7) If you use a bag leak detection system, you must keep the records specified in paragraphs (c)(7)(i) through (iii) of this section.

(i) Records of the bag leak detection system output.

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings.

(iii) The date and time of all bag leak detection system alarms, and for each valid alarm, the time you initiated corrective action, the corrective action taken, and the date on which corrective action was completed.

(d) Your records must be in a form suitable and readily available for expeditious review. You must keep each record for 5 years following the date of each recorded action. You must keep each record on-site or be accessible from a central location by computer or other means that instantly provide access at the site for at least 2 years after the date of each recorded action. You may keep the records off site for the remaining 3 years.

(e)(1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart to EPA's WebFIRE database by using CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see <http://www.epa.gov/ttn/chief/ert/index.html>). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must

submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including CBI, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator at the appropriate address listed in § 63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation test as defined in § 63.2, you must submit relative accuracy test audit (RATA) data to EPA's CDX by using CEDRI in accordance with paragraph (e)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator shall submit the results of the performance evaluation in paper submissions to the Administrator at the appropriate address listed in § 63.13.

(f) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(g) If you have switched fuels or made a physical change to the boiler and the fuel switch or change resulted in the applicability of a different subcategory within subpart JJJJJJ, in the boiler becoming subject to subpart JJJJJJ, or in the boiler switching out of subpart JJJJJJ due to a change to 100 percent natural gas, or you have taken a permit limit that resulted in you being subject to subpart JJJJJJ, you must provide notice of the date upon which you switched fuels, made the physical change, or took a permit limit within 30 days of the change. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that have switched fuels, were physically changed, or took a permit limit, and the date of the notice.

(2) The date upon which the fuel switch, physical change, or permit limit occurred.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7511, Feb. 1, 2013] .

§ 63.11226 Affirmative defense for violation of emission standards during malfunction.

In response to an action to enforce the standards set forth in § 63.11201 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) *Assertion of affirmative defense.* To establish the affirmative defense in any action to enforce

such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when a violation occurred; and

(3) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

[78 FR 7513, Feb. 1, 2013]

Other Requirements and Information

§ 63.11235 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.11236 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by EPA or an administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraphs (c) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency.

(c) The authorities that cannot be delegated to state, local, or tribal agencies are specified in paragraphs (c)(1) through (5) of this section.

(1) Approval of an alternative non-opacity emission standard and work practice standards in § 63.11223(a).

(2) Approval of alternative opacity emission standard under § 63.6(h)(9).

(3) Approval of major change to test methods under § 63.7(e)(2)(ii) and (f). A “major change to test method” is defined in § 63.90.

(4) Approval of a major change to monitoring under § 63.8(f). A “major change to monitoring” is defined in § 63.90.

(5) Approval of major change to recordkeeping and reporting under § 63.10(f). A “major change to recordkeeping/reporting” is defined in § 63.90.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7513, Feb. 1, 2013]

§ 63.11237 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2 (the General Provisions), and in this section as follows:

10-day rolling average means the arithmetic mean of all valid hours of data from 10 successive operating days, except for periods of startup and shutdown and periods when the unit is not operating.

30-day rolling average means the arithmetic mean of all valid hours of data from 30 successive operating days, except for periods of startup and shutdown and periods when the unit is not operating.

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Bag leak detection system means a group of instruments that are capable of monitoring particulate matter loadings in the exhaust of a fabric filter (*i.e.*, baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

Biodiesel means a mono-alkyl ester derived from biomass and conforming to ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see § 63.14).

Biomass means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue and wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (e.g., almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste.

Biomass subcategory includes any boiler that burns any biomass and is not in the coal subcategory.

Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of *Boiler* .

Boiler system means the boiler and associated components, such as, feedwater systems, combustion air systems, fuel systems (including burners), blowdown systems, combustion control systems, steam systems, and condensate return systems, directly connected to and serving the energy use systems.

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of “coal” includes synthetic fuels derived from coal including, but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

Coal subcategory includes any boiler that burns any solid fossil fuel and no more than 15 percent biomass on an annual heat input basis.

Commercial boiler means a boiler used in commercial establishments such as hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

Common stack means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown and periods when the unit is not operating.

Deviation (1) Means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see § 63.14).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

Electric boiler means a boiler in which electric heating serves as the source of heat. Electric boilers that burn gaseous or liquid fuel during periods of electrical power curtailment or failure are included in this definition.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be “capable of combusting” fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2015.

Electrostatic precipitator (ESP) means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.

Energy assessment means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers with less than 0.3 trillion Btu per year (TBtu/year) heat input capacity will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (e.g., steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour energy assessment.

(2) The energy assessment for facilities with affected boilers with 0.3 to 1.0 TBtu/year heat input capacity will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 33 percent of the affected boiler(s) energy (e.g., steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour energy assessment.

(3) The energy assessment for facilities with affected boilers with greater than 1.0 TBtu/year heat input capacity will be up to 24 on-site technical labor hours in length for the first TBtu/year plus 8 on-site technical labor hours for every additional 1.0 TBtu/year not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 20 percent of the affected boiler(s) energy (e.g., steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use system(s) serving as the basis for the percent of affected boiler(s) energy production, as applicable, in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z).

Energy management program means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

Energy use system (1) Includes the following systems located on the site of the affected boiler that use energy provided by the boiler:

(i) Process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air conditioning systems; hot water systems; building envelop; and lighting; or

(ii) Other systems that use steam, hot water, process heat, or electricity, provided by the affected boiler.

(2) Energy use systems are only those systems using energy clearly produced by affected boilers.

Equivalent means the following only as this term is used in Table 5 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or

EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining mercury using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing this

metal. On the other hand, if metals analysis is done on an “as received” basis, a separate aliquot can be dried to determine moisture content and the mercury concentration mathematically adjusted to a dry basis.

(6) An equivalent mercury determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for mercury and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 5 to this subpart for the same purpose.

Fabric filter means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse. A fabric filter is a dry control system.

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Gaseous fuels includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, hydrogen, and biogas.

Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

Heat input means heat derived from combustion of fuel in a boiler and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass fuel and hot water is withdrawn for use external to the vessel. Hot water boilers (*i.e.*, not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 million Btu per hour heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on-demand hot water.

Hourly average means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Institutional boiler means a boiler used in institutional establishments such as, but not limited to,

medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, and governmental buildings to provide electricity, steam, and/or hot water.

Limited-use boiler means any boiler that burns any amount of solid or liquid fuels and has a federally enforceable average annual capacity factor of no more than 10 percent.

Liquid fuel includes, but is not limited to, distillate oil, residual oil, any form of liquid fuel derived from petroleum, used oil meeting the specification in 40 CFR 279.11, liquid biofuels, biodiesel, and vegetable oil, and comparable fuels as defined under 40 CFR 261.38.

Load fraction means the actual heat input of a boiler divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (e.g., for 50 percent load the load fraction is 0.5).

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable carbon monoxide emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average scrubber liquid flow rate (e.g., to the particulate matter scrubber) measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions (i.e., a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals). Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane-derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8 .

Oil subcategory includes any boiler that burns any liquid fuel and is not in either the biomass or coal subcategories. Gas-fired boilers that burn liquid fuel only during periods of gas curtailment, gas supply interruptions, startups, or for periodic testing are not included in this definition. Periodic testing on liquid

fuel shall not exceed a combined total of 48 hours during any calendar year.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location. This definition includes oxygen trim systems.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or carbon monoxide monitor that automatically provides a feedback signal to the combustion air controller.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

Performance testing means the collection of data resulting from the execution of a test method used (either by stack testing or fuel analysis) to demonstrate compliance with a relevant emission standard.

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. Process heaters include units that heat water/water mixtures for pool heating, sidewalk heating, cooling tower water heating, power washing, or oil heating.

Qualified energy assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

- (i) Boiler combustion management.
- (ii) Boiler thermal energy recovery, including
 - (A) Conventional feed water economizer,
 - (B) Conventional combustion air preheater, and
 - (C) Condensing economizer.
- (iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vii) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Regulated gas stream means an offgas stream that is routed to a boiler for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

Residential boiler means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) used primarily to provide heat and/or hot water for:

(1) A dwelling containing four or fewer families, or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396-10 (incorporated by reference, see § 63.14(b)).

Responsible official means responsible official as defined in § 70.2.

Seasonal boiler means a boiler that undergoes a shutdown for a period of at least 7 consecutive months (or 210 consecutive days) each 12-month period due to seasonal conditions, except for periodic testing. Periodic testing shall not exceed a combined total of 15 days during the 7-month shutdown. This definition only applies to boilers that would otherwise be included in the biomass subcategory or the oil subcategory.

Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam or heat from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler.

Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire-derived fuel.

Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel.

Startup means either the first-ever firing of fuel in a boiler for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler is supplied for heating and/or producing electricity, or for any other purpose.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location within the facility and performs the same or similar function will be included in calculating the consecutive time period unless there is a gap in operation of 12 months or more.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Tune-up means adjustments made to a boiler in accordance with the procedures outlined in § 63.11223(b).

Vegetable oil means oils extracted from vegetation.

Voluntary Consensus Standards (VCS) mean technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, <http://www.astm.org>), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, <http://www.asme.org>), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, +41 22 749 01 11, <http://www.iso.org/iso/home.htm>), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 <http://www.stadards.org.au>), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, +44 (0)20 8996 9001, <http://www.bsigroup.com>), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada,

800-463-6727, <http://www.csa.ca>), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B-1000 Brussels, Belgium +32 2 550 08 11, <http://www.cen.eu/cen>), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, +49 211 6214-230, <http://www.vdi.eu>). The types of standards that are not considered VCS are standards developed by: the United States, e.g., California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, e.g., Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

Waste heat boiler means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

Wet scrubber means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to section 112(h) of the Clean Air Act.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7513, Feb. 1, 2013]

Table 1 to Subpart JJJJJ of Part 63—Emission Limits

As stated in § 63.11201, you must comply with the following applicable emission limits:

If your boiler is in this subcategory . . .	For the following pollutants . . .	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown . . .
1. New coal-fired boilers with heat input capacity of 30 million British thermal units per hour (MMBtu/hr) or greater that do not meet the definition of limited-use boiler	a. PM (Filterable) b. Mercury c. CO	3.0E-02 pounds(lb) per million British thermal units (MMBtu) of heat input. 2.2E-05 lb per MMBtu of heat input. 420 parts per million (ppm) by volume on a dry basis corrected to 3 percent oxygen (3-run average or 10-day rolling average).
2. New coal-fired boilers with heat input capacity of between 10 and 30 MMBtu/hr that do not meet the definition of limited-use boiler	a. PM (Filterable) b. Mercury c. CO	4.2E-01 lb per MMBtu of heat input. 2.2E-05 lb per MMBtu of heat input. 420 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average or 10-day rolling average).
3. New biomass-fired boilers with heat input capacity of 30 MMBtu/hr or greater that do not meet the definition of seasonal boiler or limited-use boiler	PM (Filterable)	3.0E-02 lb per MMBtu of heat input.
4. New biomass fired boilers with heat input capacity of between 10 and 30 MMBtu/hr that do not meet the definition of seasonal boiler or	PM (Filterable)	7.0E-02 lb per MMBtu of heat input.

limited-use boiler		
5. New oil-fired boilers with heat input capacity of 10 MMBtu/hr or greater that do not meet the definition of seasonal boiler or limited-use boiler	PM (Filterable)	3.0E-02 lb per MMBtu of heat input.
6. Existing coal-fired boilers with heat input capacity of 10 MMBtu/hr or greater that do not meet the definition of limited-use boiler	a. Mercury b. CO	2.2E-05 lb per MMBtu of heat input. 420 ppm by volume on a dry basis corrected to 3 percent oxygen.

[78 FR 7517, Feb. 1, 2013]

Table 2 to Subpart JJJJJJ of Part 63—Work Practice Standards, Emission Reduction Measures, and Management Practices

As stated in § 63.11201, you must comply with the following applicable work practice standards, emission reduction measures, and management practices:

If your boiler is in this subcategory . . .	You must meet the following . . .
1. Existing or new coal-fired, new biomass-fired, or new oil-fired boilers (units with heat input capacity of 10 MMBtu/hr or greater)	Minimize the boiler's startup and shutdown periods and conduct startups and shutdowns according to the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available.
2. Existing coal-fired boilers with heat input capacity of less than 10 MMBtu/hr that do not meet the definition of limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.
3. New coal-fired boilers with heat input capacity of less than 10 MMBtu/hr that do not meet the definition of limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
4. Existing oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.
5. New oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or	Conduct a tune-up of the boiler biennially as specified in § 63.11223.

limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	
6. Existing biomass-fired boilers that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.
7. New biomass-fired boilers that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
8. Existing seasonal boilers	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
9. New seasonal boilers	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
10. Existing limited-use boilers	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
11. New limited-use boilers	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
12. Existing oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
13. New oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
14. Existing coal-fired, biomass-fired, or oil-fired boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
15. New coal-fired, biomass-fired, or oil-fired boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
16. Existing coal-fired, biomass-fired, or oil-fired boilers (units with heat input capacity of 10 MMBtu/hr and greater), not including limited-use boilers	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table satisfies the energy assessment requirement. Energy assessor approval and qualification requirements are waived in instances where past or amended energy assessments are used to meet the energy assessment requirements. A facility that operates under an

	energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items (1) to (4) appropriate for the on-site technical hours listed in § 63.11237:
	(1) A visual inspection of the boiler system,
	(2) An evaluation of operating characteristics of the affected boiler systems, specifications of energy use systems, operating and maintenance procedures, and unusual operating constraints,
	(3) An inventory of major energy use systems consuming energy from affected boiler(s) and which are under control of the boiler owner or operator,
	(4) A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage,
	(5) A list of major energy conservation measures that are within the facility's control,
	(6) A list of the energy savings potential of the energy conservation measures identified, and
	(7) A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

[78 FR 7518, Feb. 1, 2013]

Table 3 to Subpart JJJJJJ of Part 63—Operating Limits for Boilers With Emission Limits

As stated in § 63.11201, you must comply with the applicable operating limits:

If you demonstrate compliance with applicable emission limits using . . .	You must meet these operating limits except during periods of startup and shutdown . . .
1. Fabric filter control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR b. Install and operate a bag leak detection system according to § 63.11224 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period.
2. Electrostatic precipitator control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR b. Maintain the 30-day rolling average total secondary electric power of the electrostatic precipitator at or above the minimum total secondary electric power as defined in § 63.11237.
3. Wet scrubber control	Maintain the 30-day rolling average pressure drop across the wet scrubber at or above the minimum scrubber pressure drop as defined in § 63.11237 and the 30-day rolling average liquid flow rate at or above the minimum scrubber liquid flow rate as defined in § 63.11237.
4. Dry sorbent or activated carbon injection control	Maintain the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent injection rate or minimum activated carbon injection rate as defined in § 63.11237. When your boiler operates at lower loads, multiply your sorbent or activated carbon injection rate by the load fraction (e.g., actual heat input divided by the heat input during the performance stack test; for 50 percent load, multiply the injection rate operating limit by 0.5).

5. Any other add-on air pollution control type.	This option is for boilers that operate dry control systems. Boilers must maintain opacity to less than or equal to 10 percent opacity (daily block average).
6. Fuel analysis	Maintain the fuel type or fuel mixture (annual average) such that the mercury emission rate calculated according to § 63.11211(c) are less than the applicable emission limit for mercury.
7. Performance stack testing	For boilers that demonstrate compliance with a performance stack test, maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance stack test.
8. Oxygen analyzer system	For boilers subject to a CO emission limit that demonstrate compliance with an oxygen analyzer system as specified in § 63.11224(a), maintain the 30-day rolling average oxygen level at or above the minimum oxygen level as defined in § 63.11237. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.11224(a)(7).

[78 FR 7519, Feb. 1, 2013]

Table 4 to Subpart JJJJJJ of Part 63—Performance (Stack) Testing Requirements

As stated in § 63.11212, you must comply with the following requirements for performance (stack) test for affected sources:

To conduct a performance test for the following pollutant. . .	You must. . .	Using. . .
1. Particulate Matter	a. Select sampling ports location and the number of traverse points	Method 1 in appendix A-1 to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G in appendix A-2 to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A-2 to part 60 of this chapter, or ASTM D6522-00 (Reapproved 2005), ^a or ANSI/ASME PTC 19.10-1981. ^a
	d. Measure the moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter.
	e. Measure the particulate matter emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A-3 and A-6 to part 60 of this chapter and a minimum 1 dscm of sample volume per run.
	f. Convert emissions concentration to lb/MMBtu emission rates	Method 19 F-factor methodology in appendix A-7 to part 60 of this chapter.
2. Mercury	a. Select sampling ports location and the number of traverse	Method 1 in appendix A-1 to part 60 of this chapter.

	points	
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G in appendix A-2 to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A-2 to part 60 of this chapter, or ASTM D6522-00 (Reapproved 2005), ^a or ANSI/ASME PTC 19.10-1981. ^a
	d. Measure the moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B in appendix A-8 to part 60 of this chapter or Method 101A in appendix B to part 61 of this chapter or ASTM Method D6784-02. ^a Collect a minimum 2 dscm of sample volume with Method 29 of 101A per run. Use a minimum run time of 2 hours with Method 30A.
	f. Convert emissions concentration to lb/MMBtu emission rates	Method 19 F-factor methodology in appendix A-7 to part 60 of this chapter.
3. Carbon Monoxide	a. Select the sampling ports location and the number of traverse points	Method 1 in appendix A-1 to part 60 of this chapter.
	b. Determine oxygen and carbon dioxide concentrations of the stack gas	Method 3A or 3B in appendix A-2 to part 60 of this chapter, or ASTM D6522-00 (Reapproved 2005), ^a or ANSI/ASME PTC 19.10-1981. ^a
	c. Measure the moisture content of the stack gas	Method 4 in appendix A-3 to part 60 of this chapter.
	d. Measure the carbon monoxide emission concentration	Method 10, 10A, or 10B in appendix A-4 to part 60 of this chapter or ASTM D6522-00 (Reapproved 2005) ^a and a minimum 1 hour sampling time per run.

^a Incorporated by reference, see § 63.14.

Table 5 to Subpart JJJJJ of Part 63—Fuel Analysis Requirements

As stated in § 63.11213, you must comply with the following requirements for fuel analysis testing for affected sources:

To conduct a fuel analysis for the following pollutant . . .	You must. . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.11213(b) or ASTM D2234/D2234M ^a (for coal) or ASTM D6323 ^a (for biomass) or equivalent.
	b. Compose fuel samples	Procedure in § 63.11213(b) or equivalent.

	c. Prepare composited fuel samples	EPA SW-846-3050B ^a (for solid samples) or EPA SW-846-3020A ^a (for liquid samples) or ASTM D2013/D2013M ^a (for coal) or ASTM D5198 ^a (for biomass) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 ^a (for coal) or ASTM E711 ^a (for biomass) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 ^a or ASTM E871 ^a or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722 ^a (for coal) or EPA SW-846-7471B ^a (for solid samples) or EPA SW-846-7470A ^a (for liquid samples) or equivalent.
	g. Convert concentrations into units of lb/MMBtu of heat content	

^a Incorporated by reference, see § 63.14.

Table 6 to Subpart JJJJJJ of Part 63—Establishing Operating Limits

As stated in § 63.11211, you must comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. PM or mercury	a. Wet scrubber operating parameters	Establish site-specific minimum scrubber pressure drop and minimum scrubber liquid flow rate operating limits according to § 63.11211(b)	Data from the pressure drop and liquid flow rate monitors and the PM or mercury performance stack tests	(a) You must collect pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance stack tests;
				(b) Determine the average pressure drop and liquid flow rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
	b. Electrostatic precipitator operating parameters	Establish a site-specific minimum total secondary electric power operating limit according to § 63.11211(b)	Data from the secondary electric power monitors and the PM or mercury performance stack tests	(a) You must collect secondary electric power data every 15 minutes during the entire period of the performance stack tests;

				(b) Determine the average total secondary electric power for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
2. Mercury	Dry sorbent or activated carbon injection rate operating parameters	Establish a site-specific minimum sorbent or activated carbon injection rate operating limit according to § 63.11211(b)	Data from the sorbent or activated carbon injection rate monitors and the mercury performance stack tests	(a) You must collect sorbent or activated carbon injection rate data every 15 minutes during the entire period of the performance stack tests;
				(b) Determine the average sorbent or activated carbon injection rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
				(c) When your unit operates at lower loads, multiply your sorbent or activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance stack test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
3. CO	Oxygen	Establish a unit-specific limit for minimum oxygen level	Data from the oxygen analyzer system specified in § 63.11224(a)	(a) You must collect oxygen data every 15 minutes during the entire period of the performance stack tests;
				(b) Determine the average hourly oxygen concentration for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
4. Any pollutant for which compliance is demonstrated by	Boiler operating load	Establish a unit-specific limit for maximum operating load according to	Data from the operating load monitors (fuel feed monitors or	(a) You must collect operating load data (fuel feed rate or steam generation data) every 15

a performance stack test		§ 63.11212(c)	steam generation monitors)	minutes during the entire period of the performance test.
				(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

[78 FR 7520, Feb. 1, 2013]

Table 7 to Subpart JJJJJ of Part 63—Demonstrating Continuous Compliance

As stated in § 63.11222, you must show continuous compliance with the emission limitations for affected sources according to the following:

If you must meet the following operating limits . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.11224(e) and § 63.11221; and
	b. Reducing the opacity monitoring data to 6-minute averages; and
	c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to § 63.11224(f) and operating the fabric filter such that the requirements in § 63.11222(a)(4) are met.
3. Wet Scrubber Pressure Drop and Liquid Flow Rate	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.11224 and 63.11221; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average pressure drop and liquid flow rate at or above the minimum pressure drop and minimum liquid flow rate according to § 63.11211.
4. Dry Scrubber Sorbent or Activated Carbon Injection Rate	a. Collecting the sorbent or activated carbon injection rate monitoring system data for the dry scrubber according to §§ 63.11224 and 63.11221; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent or activated carbon injection rate according to § 63.11211.
5. Electrostatic Precipitator Total Secondary Electric Power	a. Collecting the total secondary electric power monitoring system data for the electrostatic precipitator according to §§ 63.11224 and 63.11221; and

	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average total secondary electric power at or above the minimum total secondary electric power according to § 63.11211.
6. Fuel Pollutant Content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.11213 as applicable; and
	b. Keeping monthly records of fuel use according to §§ 63.11222(a)(2) and 63.11225(b)(4).
7. Oxygen content	a. Continuously monitoring the oxygen content of flue gas according to § 63.11224 (This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.11224(a)(7)); and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average oxygen content at or above the minimum oxygen level established during the most recent CO performance test.
8. CO emissions	a. Continuously monitoring the CO concentration in the combustion exhaust according to §§ 63.11224 and 63.11221; and
	b. Correcting the data to 3 percent oxygen, and reducing the data to 1-hour averages; and
	c. Reducing the data from the hourly averages to 10-day rolling averages; and
	d. Maintaining the 10-day rolling average CO concentration at or below the applicable emission limit in Table 1 to this subpart.
9. Boiler operating load	a. Collecting operating load data (fuel feed rate or steam generation data) every 15 minutes; and
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average at or below the operating limit established during the performance test according to § 63.11212(c) and Table 6 to this subpart.

[78 FR 7521, Feb. 1, 2013]

Table 8 to Subpart JJJJJJ of Part 63—Applicability of General Provisions to Subpart JJJJJJ

As stated in § 63.11235, you must comply with the applicable General Provisions according to the following:

General provisions cite	Subject	Does it apply?
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.11237.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	No
§ 63.6(a), (b)(1)-(b)(5), (b)(7), (c), (f)(2)-(3), (g), (i), (j)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. See § 63.11205 for general duty requirement.

§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(3)	SSM Plan	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.6(h)(2) to (9)	Determining compliance with opacity emission standards	Yes.
§ 63.7(a), (b), (c), (d), (e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Performance testing	No. See § 63.11210.
§ 63.8(a), (b), (c)(1), (c)(1)(ii), (c)(2) to (c)(9), (d)(1) and (d)(2), (e), (f), and (g)	Monitoring Requirements	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification Requirements	Yes, excluding the information required in § 63.9(h)(2)(i)(B), (D), (E) and (F). See § 63.11225.
§ 63.10(a) and (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.11225 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during SSM	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§ 63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§ 63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions	No. See § 63.11225 for malfunction recordkeeping requirements.
§ 63.10(c)(11)	Recording corrective actions	No. See § 63.11225 for malfunction recordkeeping requirements.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Allows use of SSM plan	No.

§ 63.10(d)(1) and (2)	General reporting requirements	Yes.
§ 63.10(d)(3)	Reporting opacity or visible emission observation results	No.
§ 63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§ 63.10(d)(5)	SSM reports	No. See § 63.11225 for malfunction reporting requirements.
§ 63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§ 63.1(a)(5), (a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9)	Reserved	No.

[76 FR 15591, Mar. 21, 2011, as amended at 78 FR 7521, Feb. 1, 2013]

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Third Edition, IBR approved for table 6 to subpart DDDDD.

(18) Method 6010C (SW-846-6010C), Inductively Coupled Plasma-Atomic Emission Spectrometry, Revision 3, February 2007, in EPA Publication No. SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(19) Method 7060A (SW-846-7060A), Arsenic (Atomic Absorption, Furnace Technique), Revision 1, September 1994, in EPA Publication No. SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(20) Method 7740 (SW-846-7740), Selenium (Atomic Absorption, Furnace Technique), Revision 0, September 1986, in EPA Publication No. SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

* * * *

(r) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Norcross, GA 30092, (800) 332-8686, <http://www.tappi.org>.

(1) TAPPI T 266, Determination of Sodium, Calcium, Copper, Iron, and Manganese in Pulp and Paper by Atomic Absorption Spectroscopy (Reaffirmation of T 266 om-02), Draft No. 2, July 2006, IBR approved for table 6 to subpart DDDDD.

(2) [Reserved]

Subpart JJJJJJ—[AMENDED]

■ 3. Section 63.11194 is amended by revising paragraphs (a)(1), (c) and (d), by redesignating paragraph (e) as paragraph (f) and by adding new paragraph (e) to read as follows:

§ 63.11194 What is the affected source of this subpart?

(a) * * *

(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers within a subcategory, as listed in § 63.11200 and defined in § 63.11237, located at an area source.

* * * *

(c) An affected source is a new source if you commenced construction of the affected source after June 4, 2010, and the boiler meets the applicability criteria at the time you commence construction.

(d) An affected source is a reconstructed source if the boiler meets the reconstruction criteria as defined in

§ 63.2, you commenced reconstruction after June 4, 2010, and the boiler meets the applicability criteria at the time you commence reconstruction.

(e) An existing dual-fuel fired boiler meeting the definition of gas-fired boiler, as defined in § 63.11237, that meets the applicability requirements of this subpart after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be an existing source under this subpart as long as the boiler was designed to accommodate the alternate fuel.

* * * *

■ 4. Section 63.11195 is amended by revising the introductory text and paragraphs (c) and (g) and by adding paragraphs (h) through (k) to read as follows:

§ 63.11195 Are any boilers not subject to this subpart?

The types of boilers listed in paragraphs (a) through (k) of this section are not subject to this subpart and to any requirements in this subpart.

* * * *

(c) A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (e.g., hazardous waste boilers), unless such units do not combust hazardous waste and combust comparable fuels.

* * * *

(g) Any boiler that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler is provided by regulated gas streams that are subject to another standard.

(h) Temporary boilers as defined in this subpart.

(i) Residential boilers as defined in this subpart.

(j) Electric boilers as defined in this subpart.

(k) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part.

■ 5. Section 63.11196 is amended by revising paragraphs (a)(1) and (d) to read as follows:

§ 63.11196 What are my compliance dates?

(a) * * *

(1) If the existing affected boiler is subject to a work practice or management practice standard of a tune-up, you must achieve compliance with the work practice or management

practice standard no later than March 21, 2014.

* * * *

(d) If you own or operate an industrial, commercial, or institutional boiler and would be subject to this subpart except for the exemption in § 63.11195(b) for commercial and industrial solid waste incineration units covered by 40 CFR part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the waste to fuel switch as specified in § 60.2145(a)(2) and (3) of subpart CCCC or § 60.2710(a)(2) and (3) of subpart DDDD.

■ 6. Section 63.11200 is revised to read as follows:

§ 63.11200 What are the subcategories of boilers?

The subcategories of boilers, as defined in § 63.11237 are:

(a) Coal.

(b) Biomass.

(c) Oil.

(d) Seasonal boilers.

(e) Oil-fired boilers with heat input capacity of equal to or less than 5 million British thermal units (Btu) per hour.

(f) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up.

(g) Limited-use boilers.

■ 7. Section 63.11201 is amended by revising paragraphs (b) and (d) to read as follows:

§ 63.11201 What standards must I meet?

* * * *

(b) You must comply with each work practice standard, emission reduction measure, and management practice specified in Table 2 to this subpart that applies to your boiler. An energy assessment completed on or after January 1, 2008 that meets or is amended to meet the energy assessment requirements in Table 2 to this subpart satisfies the energy assessment requirement. A facility that operates under an energy management program established through energy management systems compatible with ISO 50001, that includes the affected units, also satisfies the energy assessment requirement.

* * * *

(d) These standards apply at all times the affected boiler is operating, except during periods of startup and shutdown as defined in § 63.11237, during which time you must comply only with Table 2 to this subpart.

■ 8. Section 63.11205 is amended by revising paragraphs (b), (c) introductory

text, (c)(1) introductory text, and (c)(1)(i) to read as follows:

§ 63.11205 What are my general requirements for complying with this subpart?

* * * * *

(b) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or a continuous monitoring system (CMS), including a continuous emission monitoring system (CEMS), a continuous opacity monitoring system (COMS), or a continuous parameter monitoring system (CPMS), where applicable. You may demonstrate compliance with the applicable mercury emission limit using fuel analysis if the emission rate calculated according to § 63.11211(c) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using stack testing.

(c) If you demonstrate compliance with any applicable emission limit through performance stack testing and subsequent compliance with operating limits (including the use of CPMS), with a CEMS, or with a COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (c)(1) through (3) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses paragraphs (c)(1)(i) through (vi) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of § 63.11224.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

* * * * *

■ 9. Section 63.11210 is amended by revising paragraphs (b) through (e) and adding paragraphs (f) through (j) to read as follows:

§ 63.11210 What are my initial compliance requirements and by what date must I conduct them?

* * * * *

(b) For existing affected boilers that have applicable emission limits, you must demonstrate initial compliance with the applicable emission limits no later than 180 days after the compliance date that is specified in § 63.11196 and according to the applicable provisions in § 63.7(a)(2), except as provided in paragraph (j) of this section.

(c) For existing affected boilers that have applicable work practice standards, management practices, or emission reduction measures, you must demonstrate initial compliance no later than the compliance date that is specified in § 63.11196 and according to the applicable provisions in § 63.7(a)(2), except as provided in paragraph (j) of this section.

(d) For new or reconstructed affected boilers that have applicable emission limits, you must demonstrate initial compliance with the applicable emission limits no later than 180 days after March 21, 2011 or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(e) For new or reconstructed oil-fired boilers that combust only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM emission limit under this subpart and that do not use a post-combustion technology (except a wet scrubber) to reduce particulate matter (PM) or sulfur dioxide emissions, you are not subject to the PM emission limit in Table 1 of this subpart providing you monitor and record on a monthly basis the type of fuel combusted. If you intend to burn a new type of fuel or fuel mixture that does not meet the requirements of this paragraph, you must conduct a performance test within 60 days of burning the new fuel.

(f) For new or reconstructed affected boilers that have applicable work practice standards or management practices, you are not required to complete an initial performance tune-up, but you are required to complete the applicable biennial or 5-year tune-up as specified in § 63.11223 no later than 25 months or 61 months, respectively, after the initial startup of the new or reconstructed affected source.

(g) For affected boilers that ceased burning solid waste consistent with § 63.11196(d) and for which your initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch as specified in § 60.2145(a)(2) and (3) of subpart CCCC or

§ 60.2710(a)(2) and (3) of subpart DDDD. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(h) For affected boilers that switch fuels or make a physical change to the boiler that results in the applicability of a different subcategory within subpart JJJJJ or the boiler becoming subject to subpart JJJJJ, you must demonstrate compliance within 180 days of the effective date of the fuel switch or the physical change. Notification of such changes must be submitted according to § 63.11225(g).

(i) For boilers located at existing major sources of HAP that limit their potential to emit (e.g., make a physical change or take a permit limit) such that the existing major source becomes an area source, you must comply with the applicable provisions as specified in paragraphs (i)(1) through (3) of this section.

(1) Any such existing boiler at the existing source must demonstrate compliance with subpart JJJJJ within 180 days of the later of March 21, 2014 or upon the existing major source commencing operation as an area source.

(2) Any new or reconstructed boiler at the existing source must demonstrate compliance with subpart JJJJJ within 180 days of the later of March 21, 2011 or startup.

(3) Notification of such changes must be submitted according to § 63.11225(g).

(j) For existing affected boilers that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.11196, you must comply with the applicable provisions as specified in paragraphs (j)(1) through (3) of this section.

(1) You must complete the initial compliance demonstration, if subject to the emission limits in Table 1 to this subpart, as specified in paragraphs (a) and (b) of this section, no later than 180 days after the re-start of the affected boiler and according to the applicable provisions in § 63.7(a)(2).

(2) You must complete the initial performance tune-up, if subject to the tune-up requirements in § 63.11223, by following the procedures described in § 63.11223(b) no later than 30 days after the re-start of the affected boiler.

(3) You must complete the one-time energy assessment, if subject to the energy assessment requirements specified in Table 2 to this subpart, no

later than the compliance date specified in § 63.11196.

■ 10. Section 63.11211 is amended by revising paragraphs (a), (b)(1), and (b)(2) to read as follows:

§ 63.11211 How do I demonstrate initial compliance with the emission limits?

(a) For affected boilers that demonstrate compliance with any of the emission limits of this subpart through performance (stack) testing, your initial compliance requirements include conducting performance tests according to § 63.11212 and Table 4 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler according to § 63.11213 and Table 5 to this subpart, establishing operating limits according to § 63.11222, Table 6 to this subpart and paragraph (b) of this section, as applicable, and conducting CMS performance evaluations according to § 63.11224. For affected boilers that burn a single type of fuel, you are exempted from the compliance requirements of conducting a fuel analysis for each type of fuel burned in your boiler. For purposes of this subpart, boilers that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected boilers that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.11213 and Table 5 to this subpart.

(b) * * *

(1) For a wet scrubber, you must establish the minimum scrubber liquid flow rate and minimum scrubber pressure drop as defined in § 63.11237, as your operating limits during the three-run performance stack test. If you use a wet scrubber and you conduct separate performance stack tests for PM and mercury emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. If you conduct multiple performance stack tests, you must set the minimum scrubber liquid flow rate and pressure drop operating limits at the highest minimum values established during the performance stack tests.

(2) For an electrostatic precipitator operated with a wet scrubber, you must establish the minimum total secondary electric power (secondary voltage and secondary current), as defined in § 63.11237, as your operating limits during the three-run performance stack test.

* * * * *

■ 11. Section 63.11212 is amended by revising paragraphs (b) and (e) to read as follows:

§ 63.11212 What stack tests and procedures must I use for the performance tests?

* * * * *

(b) You must conduct each stack test according to the requirements in Table 4 to this subpart. Boilers that use a CEMS for carbon monoxide (CO) are exempt from the initial CO performance testing in Table 4 to this subpart and the oxygen concentration operating limit requirement specified in Table 3 to this subpart.

* * * * *

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 of appendix A-7 to part 60 of this chapter to convert the measured PM concentrations and the measured mercury concentrations that result from the performance test to pounds per million Btu heat input emission rates.

■ 12. Section 63.11214 is amended by revising paragraph (c) to read as follows:

§ 63.11214 How do I demonstrate initial compliance with the work practice standard, emission reduction measures, and management practice?

* * * * *

(c) If you own or operate an existing affected boiler with a heat input capacity of 10 million Btu per hour or greater, you must submit a signed certification in the Notification of Compliance Status report that an energy assessment of the boiler and its energy use systems was completed according to Table 2 to this subpart and is an accurate depiction of your facility.

* * * * *

■ 13. Section 63.11220 is revised to read as follows:

§ 63.11220 When must I conduct subsequent performance tests or fuel analyses?

(a) If your boiler has a heat input capacity of 10 million British thermal units per hour or greater, you must conduct all applicable performance (stack) tests according to § 63.11212 on a triennial basis, except as specified in paragraphs (b) through (d) of this section. Triennial performance tests must be completed no more than 37 months after the previous performance test.

(b) When demonstrating initial compliance with the PM emission limit, if your boiler's performance test results show that your PM emissions are equal to or less than half of the PM emission limit, you do not need to conduct further performance tests for PM but must continue to comply with all applicable operating limits and

monitoring requirements. If your initial performance test results show that your PM emissions are greater than half of the PM emission limit, you must conduct subsequent performance tests as specified in paragraph (a) of this section.

(c) If you demonstrate compliance with the mercury emission limit based on fuel analysis, you must conduct a fuel analysis according to § 63.11213 for each type of fuel burned as specified in paragraphs (c)(1) and (2) of this section. If you plan to burn a new type of fuel or fuel mixture, you must conduct a fuel analysis before burning the new type of fuel or mixture in your boiler. You must recalculate the mercury emission rate using Equation 1 of § 63.11211. The recalculated mercury emission rate must be less than the applicable emission limit.

(1) When demonstrating initial compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are measured to be equal to or less than half of the mercury emission limit, you do not need to conduct further fuel analysis sampling but must continue to comply with all applicable operating limits and monitoring requirements.

(2) When demonstrating initial compliance with the mercury emission limit, if the mercury constituents in the fuel or fuel mixture are greater than half of the mercury emission limit, you must conduct quarterly sampling.

(d) For existing affected boilers that have not operated since the previous compliance demonstration and more than 3 years have passed since the previous compliance demonstration, you must complete your subsequent compliance demonstration no later than 180 days after the re-start of the affected boiler.

■ 14. Section 63.11221 is revised to read as follows:

§ 63.11221 Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.11205(c).

(b) You must operate the monitoring system and collect data at all required intervals at all times the affected source is operating and compliance is required, except for periods of monitoring system malfunctions or out-of-control periods (see § 63.8(c)(7) of this part), repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks, required zero and span

adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data collected during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or quality control activities in calculations used to report emissions or operating levels. Any such periods must be reported according to the requirements in § 63.11225. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan), failure to collect required data is a deviation of the monitoring requirements.

■ 15. Section 63.11223 is amended by revising paragraphs (a), (b) introductory text, (b)(1), (b)(3) through (5), (b)(6) introductory text, (b)(6)(i), (b)(6)(iii), (b)(7), and (c), and adding paragraphs (d) through (g) to read as follows:

§ 63.11223 How do I demonstrate continuous compliance with the work practice and management practice standards?

(a) For affected sources subject to the work practice standard or the management practices of a tune-up, you must conduct a performance tune-up according to paragraph (b) of this section and keep records as required in § 63.11225(c) to demonstrate continuous compliance. You must conduct the tune-up while burning the type of fuel (or fuels in the case of boilers that routinely burn two types of fuels at the same time) that provided the majority of

the heat input to the boiler over the 12 months prior to the tune-up.

(b) Except as specified in paragraphs (c) through (f) of this section, you must conduct a tune-up of the boiler biennially to demonstrate continuous compliance as specified in paragraphs (b)(1) through (7) of this section. Each biennial tune-up must be conducted no more than 25 months after the previous tune-up. For a new or reconstructed boiler, the first biennial tune-up must be no later than 25 months after the initial startup of the new or reconstructed boiler.

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection.

* * * * *

(3) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection.

(4) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any nitrogen oxide requirement to which the unit is subject.

(5) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer.

(6) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (b)(6)(i) through (iii) of this section.

(i) The concentrations of CO in the effluent stream in parts per million, by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler.

* * * * *

(iii) The type and amount of fuel used over the 12 months prior to the tune-up of the boiler, 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) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 days of startup.

(c) Boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up must conduct a tune-up of the boiler every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed boiler with an oxygen trim system, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months.

(d) Seasonal boilers must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed seasonal boiler, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months. Seasonal boilers are not subject to the emission limits in Table 1 to this subpart or the operating limits in Table 3 to this subpart.

(e) Oil-fired boilers with a heat input capacity of equal to or less than 5 million Btu per hour must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed oil-fired boiler with a heat input capacity of equal to or less than 5 million Btu per hour, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified

in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months.

(f) Limited-use boilers must conduct a tune-up every 5 years as specified in paragraphs (b)(1) through (7) of this section. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed limited-use boiler, the first 5-year tune-up must be no later than 61 months after the initial startup. You may delay the burner inspection specified in paragraph (b)(1) of this section and inspection of the system controlling the air-to-fuel ratio specified in paragraph (b)(3) of this section until the next scheduled unit shutdown, but you must inspect each burner and system controlling the air-to-fuel ratio at least once every 72 months. Limited-use boilers are not subject to the emission limits in Table 1 to this subpart, the energy assessment requirements in Table 2 to this subpart, or the operating limits in Table 3 to this subpart.

(g) If you own or operate a boiler subject to emission limits in Table 1 of this subpart, you 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, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if

manufacturer's recommended procedures are not available.

■ 16. Section 63.11224 is amended by:

■ a. Revising paragraphs (a) introductory text, (a)(1) through (3), (a)(5), (a)(6),

■ b. Adding paragraph (a)(7).

■ c. Revising paragraphs (c)(1) introductory text, (c)(2) introductory text, and (d).

■ d. Revising paragraphs (e) introductory text, (e)(6), and (e)(7).

■ e. Adding paragraph (e)(8).

■ f. Revising paragraph (f)(7).

The revisions and additions read as follows:

§ 63.11224 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler is subject to a CO emission limit in Table 1 to this subpart, you must either install, operate, and maintain a CEMS for CO and oxygen according to the procedures in paragraphs (a)(1) through (6) of this section, or install, calibrate, operate, and maintain an oxygen analyzer system, as defined in § 63.11237, according to the manufacturer's recommendations and paragraphs (a)(7) and (d) of this section, as applicable, by the compliance date specified in § 63.11196. Where a certified CO CEMS is used, the CO level shall be monitored at the outlet of the boiler, after any add-on controls or flue gas recirculation system and before release to the atmosphere. Boilers that use a CO CEMS are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in § 63.11211(a) of this subpart. Oxygen monitors and oxygen trim systems must be installed to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location.

(1) Each CO CEMS must be installed, operated, and maintained according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, and each oxygen CEMS must be installed, operated, and maintained according to Performance Specification 3 at 40 CFR part 60, appendix B. Both the CO and oxygen CEMS must also be installed, operated, and maintained according to the site-specific monitoring plan developed according to paragraph (c) of this section.

(2) You must conduct a performance evaluation of each CEMS according to the requirements in § 63.8(e) and according to Performance Specifications 3 and 4, 4A, or 4B at 40 CFR part 60, appendix B.

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) every 15 minutes. You must have CEMS data values from a minimum of four successive cycles of operation representing each of the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed, to have a valid hour of data.

* * * * *

(5) You must calculate hourly averages, corrected to 3 percent oxygen, from each hour of CO CEMS data in parts per million CO concentrations and determine the 10-day rolling average of all recorded readings, except as provided in § 63.11221(c). Calculate a 10-day rolling average from all of the hourly averages collected for the 10-day operating period using Equation 2 of this section.

$$\text{10-day average} = \frac{\sum_{i=1}^n Hpvi}{n} \quad (\text{Eq. 2})$$

Where:

Hpvi = the hourly parameter value for hour i

n = the number of valid hourly parameter values collected over 10 boiler operating days

(6) For purposes of collecting CO data, you must operate the CO CEMS as specified in § 63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in § 63.11221(c). Periods when CO data are unavailable may constitute

monitoring deviations as specified in § 63.11221(d).

(7) You must operate the oxygen analyzer system at or above the minimum oxygen level that is established as the operating limit according to Table 6 to this subpart when firing the fuel or fuel mixture utilized during the most recent CO performance stack test. Operation of oxygen trim systems to meet these requirements shall not be done in a manner which compromises furnace safety.

* * * * *

(c) * * *

(1) For each CMS required in this section, you must develop, and submit to the EPA Administrator for approval upon request, a site-specific monitoring plan that addresses paragraphs (c)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan (if requested) at least 60 days before your initial performance evaluation of your CMS.

* * * * *

(2) In your site-specific monitoring plan, you must also address paragraphs (c)(2)(i) through (iii) of this section.

* * * * *

(d) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each CPMS according to the procedures in paragraphs (d)(1) through (4) of this section.

(1) The CPMS must complete a minimum of one cycle of operation every 15 minutes. You must have data values from a minimum of four successive cycles of operation representing each of the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed, to have a valid hour of data.

(2) You must calculate hourly arithmetic averages from each hour of CPMS data in units of the operating limit and determine the 30-day rolling average of all recorded readings, except as provided in § 63.11221(c). Calculate a 30-day rolling average from all of the hourly averages collected for the 30-day operating period using Equation 3 of this section.

$$\text{30-day average} = \frac{\sum_{i=1}^n Hpvi}{n} \quad (\text{Eq. 3})$$

Where:

Hpvi = the hourly parameter value for hour i

n = the number of valid hourly parameter values collected over 30 boiler operating days

(3) For purposes of collecting data, you must operate the CPMS as specified in § 63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except that you must exclude certain data as specified in § 63.11221(c). Periods when CPMS data are unavailable may constitute monitoring deviations as specified in § 63.11221(d).

(4) Record the results of each inspection, calibration, and validation check.

(e) If you have an applicable opacity operating limit under this rule, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (e)(1) through (8) of this section by the compliance date specified in § 63.11196.

* * * * *

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit.

(7) You must calculate and record 6-minute averages from the opacity monitoring data and determine and record the daily block average of recorded readings, except as provided in § 63.11221(c).

(8) For purposes of collecting opacity data, you must operate the COMS as specified in § 63.11221(b). For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, except

that you must exclude certain data as specified in § 63.11221(c). Periods when COMS data are unavailable may constitute monitoring deviations as specified in § 63.11221(d).

(f) * * *

(7) For positive pressure fabric filter systems that do not duct all compartments or cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

* * * * *

■ 17. Section 63.11225 is amended by:

■ a. Revising paragraphs (a) introductory text, (a)(1), (a)(2), (a)(4), (a)(5), (b) introductory text, (b)(2), (c) introductory text, (c)(2) introductory text, and (c)(2)(ii).

■ b. Adding paragraphs (c)(2)(iii) through (vi).

■ c. Revising paragraphs (d), (e), and (g).

The revisions and additions read as follows:

§ 63.11225 What are my notification, reporting, and recordkeeping, requirements?

(a) You must submit the notifications specified in paragraphs (a)(1) through (5) of this section to the administrator.

(1) You must submit all of the notifications in §§ 63.7(b); 63.8(e) and (f); and 63.9(b) through (e), (g), and (h) that apply to you by the dates specified in those sections except as specified in paragraphs (a)(2) and (4) of this section.

(2) An Initial Notification must be submitted no later than January 20, 2014 or within 120 days after the source becomes subject to the standard.

* * * * *

(4) You must submit the Notification of Compliance Status no later than 120 days after the applicable compliance date specified in § 63.11196 unless you must conduct a performance stack test. If you must conduct a performance stack test, you must submit the Notification of Compliance Status within 60 days of

completing the performance stack test. You must submit the Notification of Compliance Status in accordance with paragraphs (a)(4)(i) and (vi) of this section. The Notification of Compliance Status must include the information and certification(s) of compliance in paragraphs (a)(4)(i) through (v) of this section, as applicable, and signed by a responsible official.

(i) You must submit the information required in § 63.9(h)(2), except the information listed in § 63.9(h)(2)(i)(B), (D), (E), and (F). If you conduct any performance tests or CMS performance evaluations, you must submit that data as specified in paragraph (e) of this section. If you conduct any opacity or visible emission observations, or other monitoring procedures or methods, you must submit that data to the Administrator at the appropriate address listed in § 63.13.

(ii) “This facility complies with the requirements in § 63.11214 to conduct an initial tune-up of the boiler.”

(iii) “This facility has had an energy assessment performed according to § 63.11214(c).”

(iv) For units that install bag leak detection systems: “This facility complies with the requirements in § 63.11224(f).”

(v) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: “No secondary materials that are solid waste were combusted in any affected unit.”

(vi) The notification must be submitted electronically using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA’s Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written Notification of Compliance Status must be submitted to the

Administrator at the appropriate address listed in § 63.13.

(5) If you are using data from a previously conducted emission test to serve as documentation of conformance with the emission standards and operating limits of this subpart, you must include in the Notification of Compliance Status the date of the test and a summary of the results, not a complete test report, relative to this subpart.

(b) You must prepare, by March 1 of each year, and submit to the delegated authority upon request, an annual compliance certification report for the previous calendar year containing the information specified in paragraphs (b)(1) through (4) of this section. You must submit the report by March 15 if you had any instance described by paragraph (b)(3) of this section. For boilers that are subject only to a requirement to conduct a biennial or 5-year tune-up according to § 63.11223(a) and not subject to emission limits or operating limits, you may prepare only a biennial or 5-year compliance report as specified in paragraphs (b)(1) and (2) of this section.

* * * * *

(2) Statement by a responsible official, with the official's name, title, phone number, email address, and signature, certifying the truth, accuracy and completeness of the notification and a statement of whether the source has complied with all the relevant standards and other requirements of this subpart. Your notification must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility complies with the requirements in § 63.11223 to conduct a biennial or 5-year tune-up, as applicable, of each boiler."

(ii) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: "No secondary materials that are solid waste were combusted in any affected unit."

(iii) "This facility complies with the requirement in §§ 63.11214(d) and 63.11223(g) to minimize the boiler's time spent during startup and shutdown and to conduct startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available."

* * * * *

(c) You must maintain the records specified in paragraphs (c)(1) through (7) of this section.

* * * * *

(2) You must keep records to document conformance with the work practices, emission reduction measures, and management practices required by § 63.11214 and § 63.11223 as specified in paragraphs (c)(2)(i) through (vi) of this section.

* * * * *

(ii) For operating units that combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) of this chapter, you must keep a record which documents how the secondary material meets each of the legitimacy criteria under § 241.3(d)(1). If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfies the definition of processing in § 241.2 and each of the legitimacy criteria in § 241.3(d)(1) of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per § 241.4, you must keep records documenting that the material is a listed non-waste under § 241.4(a).

(iii) For each boiler required to conduct an energy assessment, you must keep a copy of the energy assessment report.

(iv) For each boiler subject to an emission limit in Table 1 to this subpart, you must also keep records of monthly fuel use by each boiler, including the type(s) of fuel and amount(s) used.

(v) For each boiler that meets the definition of seasonal boiler, you must keep records of days of operation per year.

(vi) For each boiler that meets the definition of limited-use boiler, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and records of fuel use for the days the boiler is operating.

* * * * *

(d) Your records must be in a form suitable and readily available for expeditious review. You must keep each record for 5 years following the date of each recorded action. You must keep each record on-site or be accessible from a central location by computer or other means that instantly provide access at the site for at least 2 years after the date of each recorded action. You may keep the records off site for the remaining 3 years.

(e)(1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart to EPA's WebFIRE database by using CEDRI that is accessed through EPA's CDX (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see <http://www.epa.gov/ttn/chief/ert/index.html>). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including CBI, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator at the appropriate address listed in § 63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation test as defined in § 63.2, you must submit relative accuracy test audit (RATA) data to EPA's CDX by using CEDRI in accordance with paragraph (e)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator shall submit the results of the performance evaluation in paper submissions to the Administrator at the appropriate address listed in § 63.13.

* * * * *

(g) If you have switched fuels or made a physical change to the boiler and the fuel switch or change resulted in the

applicability of a different subcategory within subpart JJJJJJ, in the boiler becoming subject to subpart JJJJJJ, or in the boiler switching out of subpart JJJJJJ due to a change to 100 percent natural gas, or you have taken a permit limit that resulted in you being subject to subpart JJJJJJ, you must provide notice of the date upon which you switched fuels, made the physical change, or took a permit limit within 30 days of the change. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that have switched fuels, were physically changed, or took a permit limit, and the date of the notice.

(2) The date upon which the fuel switch, physical change, or permit limit occurred.

18. Section 63.11226 is revised to read as follows:

§ 63.11226 Affirmative defense for violation of emission standards during malfunction.

In response to an action to enforce the standards set forth in § 63.11201 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) *Assertion of affirmative defense.* To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when a violation occurred; and

(3) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

■ 19. Section 63.11236 is amended by revising paragraph (a) to read as follows:

§ 63.11236 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by EPA or an administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency has the authority to implement and enforce this subpart.

You should contact your EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to your state, local, or tribal agency.

* * * * *

■ 20. Section 63.11237 is amended as follows:

■ a. By adding definitions in alphabetical order for “10-day rolling average,” “30-day rolling average,” “Annual heat input,” “Biodiesel,” “Calendar year,” “Common stack,” “Daily block average,” “Distillate oil,” “Electric boiler,” “Electric utility steam generating unit (EGU),” “Energy management program,” “Fluidized bed boiler,” “Fluidized bed combustion,” “Hourly average,” “Limited-use boiler,” “Load fraction,” “Minimum scrubber pressure drop,” “Minimum sorbent injection rate,” “Minimum total secondary electric power,” “Operating day,” “Oxygen analyzer system,” “Oxygen trim system,” “Process heater,” “Regulated gas stream,” “Residential boiler,” “Residual oil,” “Seasonal boiler,” “Shutdown,” “Solid fuel,” “Startup,” “Temporary boiler,” “Tune-up,” “Vegetable oil,” “Voluntary Consensus Standards (VCS),” and “Wet scrubber.”

■ b. By revising the definitions for “Bag leak detection system,” “Biomass subcategory,” “Boiler,” “Boiler system,” “Deviation,” “Dry scrubber,” “Electrostatic precipitator (ESP),” “Energy assessment,” “Energy use system,” “Federally enforceable,” “Gas-fired boiler,” “Heat input,” “Hot water heater,” “Institutional boiler,” “Liquid fuel,” “Minimum activated carbon injection rate,” “Minimum oxygen level,” “Minimum scrubber liquid flow rate,” “Natural gas,” “Oil subcategory,” “Particulate matter,” “Period of gas curtailment or supply interruption,” “Qualified Energy Assessor,” “Solid fossil fuel,” and “Waste heat boiler.”

■ c. By removing the definitions for “Annual heat input basis,” “Minimum PM scrubber pressure drop,” “Minimum sorbent flow rate,” and “Minimum voltage or amperage”.

§ 63.11237 What definitions apply to this subpart?

10-day rolling average means the arithmetic mean of all valid hours of data from 10 successive operating days, except for periods of startup and shutdown and periods when the unit is not operating.

30-day rolling average means the arithmetic mean of all valid hours of data from 30 successive operating days, except for periods of startup and shutdown and periods when the unit is not operating.

* * * * *

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Bag leak detection system means a group of instruments that are capable of monitoring particulate matter loadings in the exhaust of a fabric filter (*i.e.*, baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

Biodiesel means a mono-alkyl ester derived from biomass and conforming to ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see § 63.14).

* * * * *

Biomass subcategory includes any boiler that burns any biomass and is not in the coal subcategory.

Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of *Boiler*.

Boiler system means the boiler and associated components, such as, feedwater systems, combustion air systems, fuel systems (including burners), blowdown systems, combustion control systems, steam systems, and condensate return systems, directly connected to and serving the energy use systems.

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

* * * * *

Common stack means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating

measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown and periods when the unit is not operating.

Deviation (1) Means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751–11b (incorporated by reference, see § 63.14).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

Electric boiler means a boiler in which electric heating serves as the source of heat. Electric boilers that burn gaseous or liquid fuel during periods of electrical power curtailment or failure are included in this definition.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be “capable of combusting” fossil fuels, an EGU would need to have these fuels allowed in their

operating permits and have the appropriate fuel handling facilities on-site or otherwise available (*e.g.*, coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2015.

Electrostatic precipitator (ESP) means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.

Energy assessment means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers with less than 0.3 trillion Btu per year (TBtu/year) heat input capacity will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (*e.g.*, steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour energy assessment.

(2) The energy assessment for facilities with affected boilers with 0.3 to 1.0 TBtu/year heat input capacity will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 33 percent of the affected boiler(s) energy (*e.g.*, steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour energy assessment.

(3) The energy assessment for facilities with affected boilers with greater than 1.0 TBtu/year heat input capacity will be up to 24 on-site technical labor hours in length for the first TBtu/year plus 8 on-site technical labor hours for every additional 1.0 TBtu/year not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler

system(s) and any on-site energy use system(s) accounting for at least 20 percent of the affected boiler(s) energy (e.g., steam, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use system(s) serving as the basis for the percent of affected boiler(s) energy production, as applicable, in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z).

Energy management program means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

Energy use system (1) Includes the following systems located on the site of the affected boiler that use energy provided by the boiler:

(i) Process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air conditioning systems; hot water systems; building envelop; and lighting; or

(ii) Other systems that use steam, hot water, process heat, or electricity, provided by the affected boiler.

(2) Energy use systems are only those systems using energy clearly produced by affected boilers.

* * * * *

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by

the forward flow of air and combustion products.

* * * * *

Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

Heat input means heat derived from combustion of fuel in a boiler and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass fuel and hot water is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 million Btu per hour heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on-demand hot water.

Hourly average means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

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Institutional boiler means a boiler used in institutional establishments such as, but not limited to, medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, and governmental buildings to provide electricity, steam, and/or hot water.

Limited-use boiler means any boiler that burns any amount of solid or liquid fuels and has a federally enforceable average annual capacity factor of no more than 10 percent.

Liquid fuel includes, but is not limited to, distillate oil, residual oil, any form of liquid fuel derived from petroleum, used oil meeting the specification in 40 CFR 279.11, liquid biofuels, biodiesel, and vegetable oil,

and comparable fuels as defined under 40 CFR 261.38.

Load fraction means the actual heat input of a boiler divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (e.g., for 50 percent load the load fraction is 0.5).

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable carbon monoxide emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average scrubber liquid flow rate (e.g., to the particulate matter scrubber) measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath

the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions (*i.e.*, a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals). Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane-derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C₃H₈.

Oil subcategory includes any boiler that burns any liquid fuel and is not in either the biomass or coal subcategories. Gas-fired boilers that burn liquid fuel only during periods of gas curtailment, gas supply interruptions, startups, or for periodic testing are not included in this definition. Periodic testing on liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

* * * * *

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler flue gas, boiler firebox, or other appropriate intermediate location. This definition includes oxygen trim systems.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or carbon monoxide monitor that automatically provides a feedback signal to the combustion air controller.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

* * * * *

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler is restricted or

halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. Process heaters include units that heat water/water mixtures for pool heating, sidewalk heating, cooling tower water heating, power washing, or oil heating.

Qualified energy assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vii) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Regulated gas stream means an offgas stream that is routed to a boiler for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

Residential boiler means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (*e.g.*, university campus, military base, church grounds) or commercial/industrial facility (*e.g.*, farm) used primarily to provide heat and/or hot water for:

(1) A dwelling containing four or fewer families, or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396-10 (incorporated by reference, see § 63.14(b)).

* * * * *

Seasonal boiler means a boiler that undergoes a shutdown for a period of at least 7 consecutive months (or 210 consecutive days) each 12-month period due to seasonal conditions, except for periodic testing. Periodic testing shall not exceed a combined total of 15 days during the 7-month shutdown. This definition only applies to boilers that would otherwise be included in the biomass subcategory or the oil subcategory.

Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none of the steam or heat from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler.

Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire-derived fuel.

Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel.

Startup means either the first-ever firing of fuel in a boiler for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler is supplied for heating and/or producing electricity, or for any other purpose.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location within the facility and performs the same or similar function will be included in calculating the consecutive time period unless there is a gap in operation of 12 months or more.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water

system in an attempt to circumvent the residence time requirements of this definition.

Tune-up means adjustments made to a boiler in accordance with the procedures outlined in § 63.11223(b).

Vegetable oil means oils extracted from vegetation.

Voluntary Consensus Standards (VCS) mean technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English.

Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, <http://www.astm.org>), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, <http://www.asme.org>), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, +41 22 749 01 11, <http://www.iso.org/iso/home.htm>), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 <http://www.stadards.org.au>), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, +44 (0)20 8996 9001, <http://www.bsigroup.com>), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800–463–6727, <http://www.csa.ca>), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B–1000 Brussels, Belgium +32 2 550 08 11, <http://www.cen.eu/cen>), and German Engineering Standards (VDI VDI Guidelines

Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, +49 211 6214–230, <http://www.vdi.eu>). The types of standards that are not considered VCS are standards developed by: the United States, e.g., California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, e.g., Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

Waste heat boiler means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

Wet scrubber means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

* * * * *

■ 21. Table 1 to subpart JJJJJJ is revised to read as follows:

As stated in § 63.11201, you must comply with the following applicable emission limits:

TABLE 1 TO SUBPART JJJJJJ OF PART 63—EMISSION LIMITS

If your boiler is in this subcategory . . .	For the following pollutants . . .	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown . . .
1. New coal-fired boilers with heat input capacity of 30 million British thermal units per hour (MMBtu/hr) or greater that do not meet the definition of limited-use boiler.	a. PM (Filterable) b. Mercury c. CO	3.0E–02 pounds(lb) per million British thermal units (MMBtu) of heat input. 2.2E–05 lb per MMBtu of heat input. 420 parts per million (ppm) by volume on a dry basis corrected to 3 percent oxygen (3-run average or 10-day rolling average).
2. New coal-fired boilers with heat input capacity of between 10 and 30 MMBtu/hr that do not meet the definition of limited-use boiler.	a. PM (Filterable) b. Mercury c. CO	4.2E–01 lb per MMBtu of heat input. 2.2E–05 lb per MMBtu of heat input. 420 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average or 10-day rolling average).

TABLE 1 TO SUBPART JJJJJJ OF PART 63—EMISSION LIMITS—Continued

If your boiler is in this subcategory . . .	For the following pollutants . . .	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown . . .
3. New biomass-fired boilers with heat input capacity of 30 MMBtu/hr or greater that do not meet the definition of seasonal boiler or limited-use boiler.	PM (Filterable)	3.0E–02 lb per MMBtu of heat input.
4. New biomass fired boilers with heat input capacity of between 10 and 30 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler.	PM (Filterable)	7.0E–02 lb per MMBtu of heat input.
5. New oil-fired boilers with heat input capacity of 10 MMBtu/hr or greater that do not meet the definition of seasonal boiler or limited-use boiler.	PM (Filterable)	3.0E–02 lb per MMBtu of heat input.
6. Existing coal-fired boilers with heat input capacity of 10 MMBtu/hr or greater that do not meet the definition of limited-use boiler.	a. Mercury b. CO	2.2E–05 lb per MMBtu of heat input. 420 ppm by volume on a dry basis corrected to 3 percent oxygen.

■ 22. Table 2 to subpart JJJJJJ is revised to read as follows:

As stated in § 63.11201, you must comply with the following applicable work practice standards, emission

reduction measures, and management practices:

TABLE 2 TO SUBPART JJJJJJ OF PART 63—WORK PRACTICE STANDARDS, EMISSION REDUCTION MEASURES, AND MANAGEMENT PRACTICES

If your boiler is in this subcategory . . .	You must meet the following . . .
1. Existing or new coal-fired, new biomass-fired, or new oil-fired boilers (units with heat input capacity of 10 MMBtu/hr or greater).	Minimize the boiler's startup and shutdown periods and conduct startups and shutdowns according to the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available.
2. Existing coal-fired boilers with heat input capacity of less than 10 MMBtu/hr that do not meet the definition of limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.
3. New coal-fired boilers with heat input capacity of less than 10 MMBtu/hr that do not meet the definition of limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
4. Existing oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.
5. New oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
6. Existing biomass-fired boilers that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler biennially as specified in § 63.11223.
7. New biomass-fired boilers that do not meet the definition of seasonal boiler or limited-use boiler, or use an oxygen trim system that maintains an optimum air-to-fuel ratio.	Conduct a tune-up of the boiler biennially as specified in § 63.11223.
8. Existing seasonal boilers	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
9. New seasonal boilers	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
10. Existing limited-use boilers	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
11. New limited-use boilers	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
12. Existing oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr.	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
13. New oil-fired boilers with heat input capacity of equal to or less than 5 MMBtu/hr.	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.

TABLE 2 TO SUBPART JJJJJ OF PART 63—WORK PRACTICE STANDARDS, EMISSION REDUCTION MEASURES, AND MANAGEMENT PRACTICES—Continued

If your boiler is in this subcategory . . .	You must meet the following . . .
14. Existing coal-fired, biomass-fired, or oil-fired boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up.	Conduct an initial tune-up as specified in § 63.11214, and conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
15. New coal-fired, biomass-fired, or oil-fired boilers with an oxygen trim system that maintains an optimum air-to-fuel ratio that would otherwise be subject to a biennial tune-up.	Conduct a tune-up of the boiler every 5 years as specified in § 63.11223.
16. Existing coal-fired, biomass-fired, or oil-fired boilers (units with heat input capacity of 10 MMBtu/hr and greater), not including limited-use boilers.	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table satisfies the energy assessment requirement. Energy assessor approval and qualification requirements are waived in instances where past or amended energy assessments are used to meet the energy assessment requirements. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items (1) to (4) appropriate for the on-site technical hours listed in § 63.11237: (1) A visual inspection of the boiler system, (2) An evaluation of operating characteristics of the affected boiler systems, specifications of energy use systems, operating and maintenance procedures, and unusual operating constraints, (3) An inventory of major energy use systems consuming energy from affected boiler(s) and which are under control of the boiler owner or operator, (4) A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage, (5) A list of major energy conservation measures that are within the facility's control, (6) A list of the energy savings potential of the energy conservation measures identified, and (7) A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

■ 23. Table 3 to subpart JJJJJ is revised to read as follows:

As stated in § 63.11201, you must comply with the applicable operating limits:

TABLE 3 TO SUBPART JJJJJ OF PART 63—OPERATING LIMITS FOR BOILERS WITH EMISSION LIMITS

If you demonstrate compliance with applicable emission limits using . . .	You must meet these operating limits except during periods of startup and shutdown . . .
1. Fabric filter control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR b. Install and operate a bag leak detection system according to § 63.11224 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period.
2. Electrostatic precipitator control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR b. Maintain the 30-day rolling average total secondary electric power of the electrostatic precipitator at or above the minimum total secondary electric power as defined in § 63.11237.
3. Wet scrubber control	Maintain the 30-day rolling average pressure drop across the wet scrubber at or above the minimum scrubber pressure drop as defined in § 63.11237 and the 30-day rolling average liquid flow rate at or above the minimum scrubber liquid flow rate as defined in § 63.11237.
4. Dry sorbent or activated carbon injection control.	Maintain the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent injection rate or minimum activated carbon injection rate as defined in § 63.11237. When your boiler operates at lower loads, multiply your sorbent or activated carbon injection rate by the load fraction (e.g., actual heat input divided by the heat input during the performance stack test; for 50 percent load, multiply the injection rate operating limit by 0.5).
5. Any other add-on air pollution control type. ...	This option is for boilers that operate dry control systems. Boilers must maintain opacity to less than or equal to 10 percent opacity (daily block average).
6. Fuel analysis	Maintain the fuel type or fuel mixture (annual average) such that the mercury emission rate calculated according to § 63.11211(c) are less than the applicable emission limit for mercury.
7. Performance stack testing	For boilers that demonstrate compliance with a performance stack test, maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance stack test.
8. Oxygen analyzer system	For boilers subject to a CO emission limit that demonstrate compliance with an oxygen analyzer system as specified in § 63.11224(a), maintain the 30-day rolling average oxygen level at or above the minimum oxygen level as defined in § 63.11237. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.11224(a)(7).

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■ 24. Table 6 to subpart JJJJJJ is revised to read as follows:

As stated in § 63.11211, you must comply with the following requirements for establishing operating limits:

TABLE 6 TO SUBPART JJJJJJ OF PART 63—ESTABLISHING OPERATING LIMITS

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. PM or mercury ..	a. Wet scrubber operating parameters.	Establish site-specific minimum scrubber pressure drop and minimum scrubber liquid flow rate operating limits according to § 63.11211(b).	Data from the pressure drop and liquid flow rate monitors and the PM or mercury performance stack tests.	(a) You must collect pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average pressure drop and liquid flow rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
	b. Electrostatic precipitator operating parameters.	Establish a site-specific minimum total secondary electric power operating limit according to § 63.11211(b).	Data from the secondary electric power monitors and the PM or mercury performance stack tests.	(a) You must collect secondary electric power data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average total secondary electric power for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
2. Mercury	Dry sorbent or activated carbon injection rate operating parameters.	Establish a site-specific minimum sorbent or activated carbon injection rate operating limit according to § 63.11211(b).	Data from the sorbent or activated carbon injection rate monitors and the mercury performance stack tests.	(a) You must collect sorbent or activated carbon injection rate data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average sorbent or activated carbon injection rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run. (c) When your unit operates at lower loads, multiply your sorbent or activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance stack test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
3. CO	Oxygen	Establish a unit-specific limit for minimum oxygen level.	Data from the oxygen analyzer system specified in § 63.11224(a).	(a) You must collect oxygen data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average hourly oxygen concentration for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
4. Any pollutant for which compliance is demonstrated by a performance stack test.	Boiler operating load.	Establish a unit-specific limit for maximum operating load according to § 63.11212(c).	Data from the operating load monitors (fuel feed monitors or steam generation monitors).	(a) You must collect operating load data (fuel feed rate or steam generation data) every 15 minutes during the entire period of the performance test. (b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

■ 25. Table 7 to subpart JJJJJJ is revised to read as follows:

As stated in § 63.11222, you must show continuous compliance with the

emission limitations for each boiler according to the following:

TABLE 7 TO SUBPART JJJJJJ OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

If you must meet the following operating limits . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.11224(e) and § 63.11221; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. Fabric Filter Bag Leak Detection Operation ...	Installing and operating a bag leak detection system according to § 63.11224(f) and operating the fabric filter such that the requirements in § 63.11222(a)(4) are met.
3. Wet Scrubber Pressure Drop and Liquid Flow Rate.	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.11224 and 63.11221; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average pressure drop and liquid flow rate at or above the minimum pressure drop and minimum liquid flow rate according to § 63.11211.
4. Dry Scrubber Sorbent or Activated Carbon Injection Rate.	a. Collecting the sorbent or activated carbon injection rate monitoring system data for the dry scrubber according to §§ 63.11224 and 63.11221; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent or activated carbon injection rate according to § 63.11211.
5. Electrostatic Precipitator Total Secondary Electric Power.	a. Collecting the total secondary electric power monitoring system data for the electrostatic precipitator according to §§ 63.11224 and 63.11221; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average total secondary electric power at or above the minimum total secondary electric power according to § 63.11211.
6. Fuel Pollutant Content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.11213 as applicable; and b. Keeping monthly records of fuel use according to §§ 63.11222(a)(2) and 63.11225(b)(4).
7. Oxygen content	a. Continuously monitoring the oxygen content of flue gas according to § 63.11224 (This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.11224(a)(7)); and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average oxygen content at or above the minimum oxygen level established during the most recent CO performance test.
8. CO emissions	a. Continuously monitoring the CO concentration in the combustion exhaust according to §§ 63.11224 and 63.11221; and b. Correcting the data to 3 percent oxygen, and reducing the data to 1-hour averages; and c. Reducing the data from the hourly averages to 10-day rolling averages; and d. Maintaining the 10-day rolling average CO concentration at or below the applicable emission limit in Table 1 to this subpart.
9. Boiler operating load	a. Collecting operating load data (fuel feed rate or steam generation data) every 15 minutes; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average at or below the operating limit established during the performance test according to § 63.11212(c) and Table 6 to this subpart.

■ 26. Table 8 to subpart JJJJJJ is amended by:

■ a. Revising the entry for “§ 63.9”.

■ b. Revising the entry for “§ 63.10(e) and (f)”.

■ c. Adding an entry for “§ 63.10(f)”.

The revisions read as follows:

* * * * *

TABLE 8 TO SUBPART JJJJJJ OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART JJJJJJ

General provisions cite	Subject	Does it apply?
* * *	* * *	* * *
§ 63.9	Notification Requirements	Yes, excluding the information required in § 63.9(h)(2)(i)(B), (D), (E) and (F). See § 63.11225.
* * *	* * *	* * *
§ 63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
* * *	* * *	* * *

Appendix E

Modeling Report Form



**Minnesota Pollution
Control Agency**

520 Lafayette Road North
St. Paul, MN 55155-4194

AQDMR-01

**Air Quality Dispersion Modeling Report(AQDMR)
Protocol Form for Criteria Pollutant Modeling**

Doc Type: Air Dispersion Modeling

Acronym Information on Page 6

Instructions: Permit applicants required to conduct air dispersion modeling should submit two paper copies of the completed Air Quality Dispersion Modeling Report form (AQDMR-01) and all accompanying files to:

Air Quality Permit Document Coordinator
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

Applicants may also submit an electronic version in addition to the two paper copies.

Electronic copies of the forms and accompanying files should be sent to: AirModeling.PCA@state.mn.us.

Facility Information

AQ tracking number: _____

AQ file no.: 578 AQ facility/permit ID no.: 03700070 Today's date (mm/dd/yyyy): 5/7/2013

Three-letter modeling facility ID (ex., XEK = Xcel Energy Allen S. King, MEC = Mankato Energy Center, etc.): SMX

Facility name: Sanimax USA Inc.

Facility street address: 505 Hardman Avenue

City: South St. Paul County: Dakota

State: MN Zip code: 55075 Elevation at facility: 211 m

Facility contact: Troy Bech Protocol prepared by: Katie Hill Brandt

Facility contact phone: 651.451.6858 x1520 Preparer phone: 651.490.2032

Facility contact e-mail address: troy.bech@sanimax.com Preparer e-mail address: khillbrandt@sehinc.com

Latitude, Longitude of facility (Decimal degrees to **four** decimal places): 44.8860 N, 93.0217 W

UTM coordinates of facility (NAD83, zone 15 extended **only**): x = 498,287.30 m East, y = 4,970,287.20 m North

This report is associated with:

- ☒ Permit application
☐ Permit requirement
☐ Other: _____

Project Description (50 words or less)

Installation of a 37 MMBtu/hr boiler (SV019) firing either natural gas, no. 2 fuel oil, or propane; removal of no. 6 fuel oil as an optional fuel for SV001.

Files to Accompany Modeling Report

Include the following files with the completed modeling report form. Use checkbox to indicate that all applicable files are included.

- ☒ AERMOD input files (*.inp, *.adi, *.ami)
☒ AERMOD output files (*.out, *.ado, *.amo)
☒ AERMOD plot files (*.plt)
☐ AERMOD post files (*.pst) – If applicable
☐ AERMOD event files (*.evi, *.evo) – If applicable

☒ AERMOD miscellaneous/other files (MAXDCONT, ?, ?, etc.) – If applicable

2. AERMET files: ☒ *.sfc ☒ *.pfl
3. BPIP-PRIME files: ☒ Input (*.bpi) ☒ Output (*.bpo, *.sum)
4. AERMAP files: ☒ Terrain (*.dem(s), *.tif (NED files)), ☒ Input (*.ami), ☒ Output (*.rou, *.sou, etc.)
5. Background data files: ☐ Background concentrations for applicable pollutants (seasonal, monthly, daily, hourly, etc.)
6. Modeling Results: ☒ Figures (*.jpeg, *.pdf), ☐ GIS Maps (*.shp)
7. AQDMPS-01 spreadsheet*: ☒
8. Other files and supporting documents (SMSv*.xls, Far sources, readme, etc.):
aq2-41_Protocol_Sanimax_Rev3.xls
Sanimax PTE Calculations_2013.03.21.xlsx
Sanimax Roads Final_2013.xlsx

* Provide the final spreadsheet (i.e. AQDMPS-01) and indicate/highlight changes.

Section 1. Modeling Protocol

1. The Air Dispersion Modeling presented in this report is based on a Protocol that has been:
☐ Approved ☒ Conditionally approved ☒ *MPCA approval date (mm/dd/yyyy): 04/11/2013 (via email)
**This is the date given on AQDM PAN-01 form*
2. Does this Modeling submittal **completely** follow the Approved Protocol? ☒ Yes ☐ No
If yes, proceed to Section 3.
If no, proceed to Section 2.

Section 2. Changes to Modeling Protocol

Table 1: Protocol Changes (Please indicate which sections in Approved Protocol contain changes.)

Modeling protocol by sections	
Section and section name	Change/No change
Files to accompany protocol	No Change
Section A <i>Purpose for Air Dispersion Modeling and Related Information</i>	No Change
Section B <i>EPA Pre-Processors and EPA Post-Processors</i>	No Change
Section C <i>Model Selection and Options (Key CO Pathway Inputs)</i>	No Change
Section D <i>Emission Source Characterizations and Parameters (Key SO Pathway Inputs)</i>	No Change
Section E <i>Paved Roads Fugitive Dust (as per MPCA April 25, 2011 Policy)</i>	No Change
Section F <i>Receptors (RE Pathway)</i>	No Change
Section G <i>Meteorological Data (ME Pathway)</i>	No Change
Section H <i>SIL Analysis and Results</i>	No Change
Section I <i>Background Values</i>	No Change
Section J <i>Nearby Sources</i>	No Change
Section K <i>Anticipated Outputs (OU Pathway)</i>	No Change

Section 2.1: Detailed Changes to Modeling Protocol

Please provide specific information corresponding to those sections in Table 1 where changes are indicated.

Section A. Purpose for air dispersion modeling and related information

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes and/or indicate section item number(s):

Section B. EPA pre-processors and EPA post-processors

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes and/or indicate section item number(s):

Section C. Model selection and options (Key CO pathway inputs)

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes and/or indicate section item number(s):

Section D. Emission source characterizations and parameters (Key SO pathway inputs)

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes and/or indicate section item number(s):

Section E. Paved roads fugitive dust

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes and/or indicate section item number(s):

Section F. Receptors (RE pathway)

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes and/or indicate section item number(s):

Section G. Meteorological data (ME pathway)

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes and/or indicate section item number(s):

Section H. SIL analysis and results

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes and/or indicate section item number(s):

Section I. Background values

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes and/or indicate section item number(s):

Section J. Nearby sources

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes and/or indicate section item number(s):

Section K. Anticipated outputs (OU pathway)

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes and/or indicate section item number(s):

Section 3. Paved Roads Fugitive Dust (Optional)

Facilities that have indicated in AQDMP-01 form the exclusion of paved roads in the air dispersion modeling should provide the results of that modeling in Table 1. (See the AQDMP-01 form for details.)

Table 1: Paved Road Dust modeling results

	Averaging Period	NAAQS ($\mu\text{g}/\text{m}^3$)	Total Modeled NAAQS Concentration (includes Background and Nearby Sources) ($\mu\text{g}/\text{m}^3$)	% of NAAQS	PSD Class II Increments ($\mu\text{g}/\text{m}^3$)	Modeled Class II Increment Impact Concentrations ($\mu\text{g}/\text{m}^3$)	% of Class II Increments
PM ₁₀	24-hour	150		0.00%	30		0.00%
	Annual	50		0.00%	17		0.00%
PM _{2.5}	24-hour	35		0.00%	9		0.00%
	Annual	15		0.00%	4		0.00%

Section 4. Modeling Results

Table 2: Pollutants and averaging periods (Indicate with an "X" all pollutant and averaging period(s) modeled.)

Pollutant	Averaging Period	Standard		Increment
		NAAQS	MAAQS	
CO	1-hr			
	8-hr			
Lead	Rolling 3 mo. Avg			
	Quarterly Avg			
NO ₂	1-hr			
	Annual			
SO ₂	1-hr			
	3-hr			
	24-hr			
	Annual			

PM ₁₀	24-hr	X		
	Annual	X		
PM _{2.5}	24-hr			
	Annual			

Table 3: NAAQS/MAAQs modeling results (Enter modeling results along with the percent of standard.)

Pollutant	Averaging period	NAAQS standard (ug/m ³)	MAAQs standard (ug/m ³)	Total modeled concentration (includes background and nearby sources) (ug/m ³)	Percent of standard (%)	
					NAAQS	MAAQs
CO	1-hr	40,000	35,000			
	8-hr	10,000	10,000			
Lead	Rolling 3 mo. Avg	0.15	***			
	Quarterly Avg	1.5	1.5			
NO ₂	1-hr	188	***			
	Annual	100	100			
SO ₂	1-hr	196	1300			
	3-hr	***	1300/*915			
	24-hr	365	365			
	Annual	80	60			
PM ₁₀	24-hr	150	150			
	Annual	***	50			
PM _{2.5}	24-hr	35	65	34.97107	99.91	
	Annual	15	15	9.91429	82.62	

*SO₂ 3-hr for Northern Minnesota is 915 ug/m³.

Table 4: Increment modeling results (Provide the increment modeling results along with the percent of standard.)

Pollutant	Averaging Period	Class II Increment (ug/m ³)	Total Modeled Concentration (includes other increment sources) (ug/m ³)	Percent of Standard (%)
NO ₂	1-hr	***		
	Annual	25		
SO ₂	1-hr	***		
	3-hr	512		
	24-hr	91		
	Annual	20		
PM ₁₀	24-hr	30		
	Annual	17		
PM _{2.5}	24-hr	9		
	Annual	4		

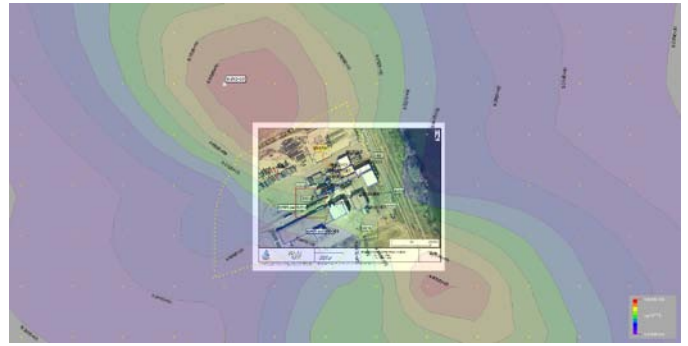
Section 5. Discussion

Enter any discussion comments:

Section 6. Modeling Results Figures/Maps

Insert a figure or map showing the facility emission sources, receptors, and the location of the modeled maximum concentration(s) for each applicable pollutant, corresponding averaging periods, and operating scenarios. Figures or maps should correspond to Section 3 NAAQS and Increment results.

See below (see also: larger versions of these files attached).



PM2.5 24-hr Figures

Figure 1 – Full Extent

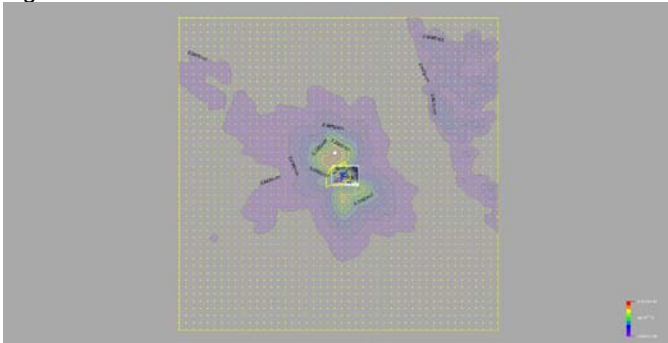
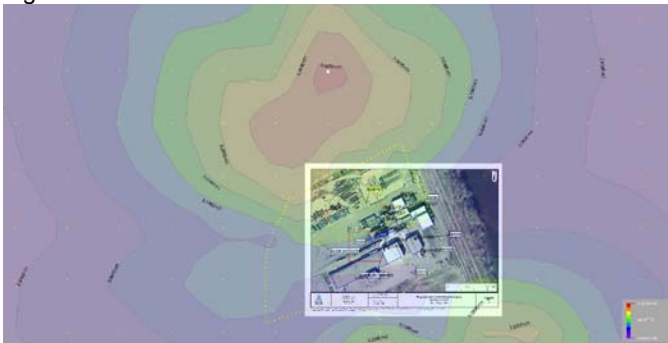


Figure 2 – Zoom In



PM2.5 Annual Figures

Figure 3 – Full Extent

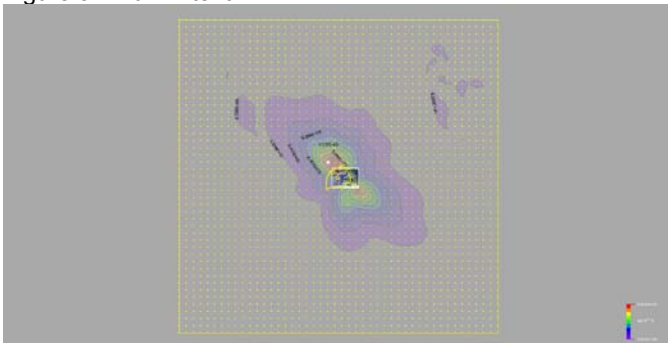


Figure 4 – Zoom In

Acronyms

$\mu\text{g}/\text{m}^3$	Micrograms per cubic meter
AERMAP	AERMOD Terrain Preprocessor
AERMET	AERMOD Meteorological Preprocessor
AERMOD	AMS/EPA Regulatory Model
AQ	Air Quality
AQDMP-01	Air Quality Dispersion Modeling Protocol form
AQDMP-01	Air Quality Dispersion Modeling Protocol Spreadsheet
BPIP-PRIME	Building Profile Input Program for PRIME
CO	Carbon Monoxide
EPA	U.S. Environmental Protection Agency
FAC	3-letter facility ID
MAAQS	Minnesota State Ambient Air Quality Standard
MPCA	Minnesota Pollution Control Agency
NAAQS	National Ambient Air Quality Standard
NO_2	Nitrogen Dioxide
OU	Operable Unit
Pb	Lead
PM_{10}	Particulate Matter less than 10 μm in size
$\text{PM}_{2.5}$	Particulate Matter less than 2.5 μm in size
PRIME	Plume Rise Model Enhancements
PSD	Prevention of Significant Deterioration Program
SIL	Significant Impact Level
SO_2	Sulfur Dioxide
SIP	State Implementation Plan
SMS	Standardized Mobile Source
UG/M3	Micrograms per cubic meter ($\mu\text{g}/\text{m}^3$)
UTM	Universal Transverse Mercator

