Tommy Downs, Mill Manager
PotlatchDeltic Manufacturing L.L.C. - Waldo Mill
P.O. Box 409
Waldo, AR 71770

Dear Mr. Downs:

The enclosed Permit No. 0697-AOP-R18 is your authority to construct, operate, and maintain the equipment and/or control apparatus as set forth in your application initially received on 11/20/2017.

After considering the facts and requirements of A.C.A. §8-4-101 et seq. as referenced by §8-4-304, and implementing regulations, I have determined that Permit No. 0697-AOP-R18 for the construction and operation of equipment at PotlatchDeltic Manufacturing L.L.C. - Waldo Mill shall be issued and effective on the date specified in the permit, unless a Commission review has been properly requested under Arkansas Department of Pollution Control & Ecology Commission's Administrative Procedures, Regulation 8, within thirty (30) days after service of this decision.

The applicant or permittee and any other person submitting public comments on the record may request an adjudicatory hearing and Commission review of the final permitting decisions as provided under Chapter Six of Regulation No. 8, Administrative Procedures, Arkansas Pollution Control and Ecology Commission. Such a request shall be in the form and manner required by Regulation 8.603, including filing a written Request for Hearing with the APC&E Commission Secretary at 101 E. Capitol Ave., Suite 205, Little Rock, Arkansas 72201. If you have any questions about filing the request, please call the Commission at 501-682-7890.

Sincerely,

[Signature]
Stuart Spencer
Associate Director, Office of Air Quality

Enclosure: Final Permit
ADEQ OPERATING AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation 26:

Permit No. : 0697-AOP-R18

IS ISSUED TO:

PotlatchDeltic Manufacturing L.L.C. - Waldo Mill
1720 Highway 82 West
Waldo, AR  71770
Columbia County
AFIN:  14-00037

THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

August 6, 2014 AND August 5, 2019

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

[Signature]
Stuart Spencer
Associate Director, Office of Air Quality

NOV 29 2018
Date
# Table of Contents

SECTION I: FACILITY INFORMATION .............................................................................. 4
SECTION II: INTRODUCTION ............................................................................................... 5
  Summary of Permit Activity .................................................................................................... 5
  Process Description .................................................................................................................. 24
  Regulations ............................................................................................................................. 25
  Emission Summary .................................................................................................................. 25
SECTION III: PERMIT HISTORY ........................................................................................ 30
SECTION IV: SPECIFIC CONDITIONS .............................................................................. 34
  SN-02 ........................................................................................................................................ 34
  SN-04, SN-05, SN-06, SN-08 and SN-30 .................................................................................. 35
  SN-09 ........................................................................................................................................ 37
  SN-16 and SN-22 ...................................................................................................................... 38
  SN-13 ........................................................................................................................................ 40
  SN-14 ........................................................................................................................................ 71
  SN-18 and SN-19 ...................................................................................................................... 76
  SN-20 ........................................................................................................................................ 78
  SN-24 ........................................................................................................................................ 84
  SN-25 ........................................................................................................................................ 85
  SN-27 and SN-29 ...................................................................................................................... 86
  SN-28 ........................................................................................................................................ 88
SECTION V: COMPLIANCE PLAN AND SCHEDULE ..................................................... 91
SECTION VI: PLANTWIDE CONDITIONS ........................................................................ 92
  Title VI Provisions .................................................................................................................... 94
SECTION VII: INSIGNIFICANT ACTIVITIES .................................................................. 97
SECTION VIII: GENERAL PROVISIONS ........................................................................... 98

APPENDIX A

40 CFR Part 60, Subpart Dc – Standards of Performance for Small Industrial/Commercial/Institutional Steam Generating Units

APPENDIX B

40 CFR Part 60, Subpart III – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

APPENDIX C

List of Acronyms and Abbreviations

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>AFIN</td>
<td>ADEQ Facility Identification Number</td>
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<tr>
<td>C.F.R.</td>
<td>Code of Federal Regulations</td>
</tr>
<tr>
<td>CO</td>
<td>Carbon Monoxide</td>
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<tr>
<td>HAP</td>
<td>Hazardous Air Pollutant</td>
</tr>
<tr>
<td>lb/hr</td>
<td>Pound Per Hour</td>
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<td>MVAC</td>
<td>Motor Vehicle Air Conditioner</td>
</tr>
<tr>
<td>No.</td>
<td>Number</td>
</tr>
<tr>
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<td>Nitrogen Oxide</td>
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<td>PM</td>
<td>Particulate Matter</td>
</tr>
<tr>
<td>PM$_{10}$</td>
<td>Particulate Matter Smaller Than Ten Microns</td>
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<td>SNAP</td>
<td>Significant New Alternatives Program (SNAP)</td>
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<td>SO$_2$</td>
<td>Sulfur Dioxide</td>
</tr>
<tr>
<td>SSM</td>
<td>Startup, Shutdown, and Malfunction Plan</td>
</tr>
<tr>
<td>Tpy</td>
<td>Tons Per Year</td>
</tr>
<tr>
<td>UTM</td>
<td>Universal Transverse Mercator</td>
</tr>
<tr>
<td>VOC</td>
<td>Volatile Organic Compound</td>
</tr>
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</table>
SECTION I: FACILITY INFORMATION

PERMITTEE: PotlatchDeltic Manufacturing L.L.C. - Waldo Mill

AFIN: 14-00037

PERMIT NUMBER: 0697-AOP-R18

FACILITY ADDRESS: 1720 Highway 82 West
Waldo, AR 71770

MAILING ADDRESS: P.O. Box 409
Waldo, AR 71770

COUNTY: Columbia County

CONTACT NAME: Tommy Downs

CONTACT POSITION: Mill Manager

TELEPHONE NUMBER: (870) 693-5555

REVIEWING ENGINEER: Jeremy Antipolo

UTM North South (Y): Zone 15: 3687722.60 m

UTM East West (X): Zone 15: 471625.90 m
SECTION II: INTRODUCTION

Summary of Permit Activity

PotlatchDeltic Manufacturing L.L.C. – Waldo Mill (Waldo Mill) currently operates a lumber and chip mill at 1720 Highway 82 West in Waldo, Arkansas 71770. The Waldo Mill is a subsidiary of PotlatchDeltic, a merger of Potlatch Corporation and Deltic Timber Corporation effective February 21, 2018. This permit modification includes the following changes:

- Modify the physical design of SN-06 Dry Kiln No. 3 to increase its maximum capacity from 13.20 MBF/hr to 13.82 MBF/hr;
- Remove SN-07 Dry Kiln No. 4, a steam heated continuous kiln, from service and replace it with a new continuous kiln, SN-30 Dry Kiln No. 6;
- Remove kiln-specific annual production limits on SN-06 and SN-08, Dry Kiln Nos. 3 and 5, respectively;
- Update the plant’s business projections to increase the facility’s permitted production capacity from 285 MMBF/yr to 300 MMBF/yr of finished product;
- Remove Planer Mill Shavings Cyclone SN-10 from service; and,
- Replace Planer Mill Shavings Cyclone SN-22.

This permitting action results with emission increases of 35.4 tpy VOC, 1.86 tpy Total HAPs and 0.27 tpy Acetone. Associated emission decreases are 65.5 tpy PM, 14.8 tpy PM10, 3.3 tpy SO2, 61.3 tpy CO, 38.7 tpy NOX, 0.039 tpy Lead, 1.65 tpy HCl and 1.20 tpy Methanol.

The proposed modifications will affect actual criteria pollutant emissions from the Waldo Mill. The following PSD applicability analysis demonstrates that the increase in criteria pollutant emissions as a result of the proposed modifications, with the exception of volatile organic compounds (VOC) and nitrogen oxides (NOx), are below PSD permitting thresholds. This analysis is an update of the PSD application that resulted in the issuance of Title V Air Permit No. 697-AOP-R13. All affected sources from the previously permitted and on-going expansion project are included in the analysis to ensure that this project is not construed as separate from the original project, but rather an extension of the on-going expansion effort.

To determine PSD applicability, the emissions increases of regulated pollutants were compared to the PSD Significant Emission Rates. Under the PSD regulations, emissions increases for new emissions units and existing emissions units are calculated differently. For changes to existing units, emissions increases may be calculated as the difference between the future projected actual and baseline actual emissions. This modification does not propose any new emission units. The proposed equipment modifications are to existing emissions units only.

Baseline Actual Emissions

Baseline actual emissions are defined by 40 CFR Part 52.21 as the average rate (in tons per year) at which the emissions unit actually emitted the pollutant during any consecutive 24-month period within the 10-year period immediately preceding the date construction begins, or the date
the permit application is received by the reviewing authority, whichever is earlier. The 24-month period from December 2013 through January 2015 was used as the baseline period in this PSD analysis for PM, PM10, PM2.5, SO2, CO, NOx, Lead, and CO2e, and the 24-month period from February 2015 through January 2017 was used as the baseline period in this PSD analysis for VOC. Baseline actual emission calculations are included in electronic form in the accompanying spreadsheet.

Projected Actual Emissions (Future Projected Actual Emissions)

Future projected actual emissions are defined by 40 CFR 52.21(b)(41)(i) as the maximum rate (in tons per year) which an existing emissions unit is projected to emit a regulated pollutant in any one of the five years following the date of the project, or in any one of the ten years following the date of a project that increases the production capacity of the equipment. For this project, a future projected actual November 17, 2017 (Updated 6/13/18) production/throughput rate of 300 MMBF/yr is proposed, based on external projected lumber demand and internal marketing goals.

Demand Growth Exclusion

According to 40 CFR 52.21(b)(41)(ii)(c), in calculating any emission increase that results from the project, the applicant “shall exclude…that portion of the unit’s emissions following the project that an existing unit could have accommodated” during the baseline period and that are “unrelated to the particular project, including any increased utilization due to product demand growth”. This provision is commonly called the “demand growth exclusion”. The amount of emissions that the Waldo Mill “could have accommodated” during the baseline period was determined, based on EPA guidance, which states that the demand growth exclusion can be calculated using the single highest month’s production rate in the 24-month baseline period annualized to an annual production total.  

Based on a study conducted by the USDA, the capacity and production of US and Canadian softwood lumber sawmills has decreased in number from 1,104 mills in 2004 to 891 mills in 2009. This decrease was due to the downturn in the housing market in the US that started in 2006 and can be seen on the graphic above. During the downturn, the Waldo Mill, in an effort to remain in business, cut production back to 75% of capacity and only operated 4 days a week. Had the market not taken the downturn, the Waldo Mill could have operated 6 days a week. Therefore, the Demand Growth calculations will be based on the highest monthly production during the baseline period annualized, consistent with the methodology in the previous PSD review of the expansion project.

Emissions Increase

1 Presented by EPA Region 4 as an acceptable approximation (Southern Section AWMA Presentation by Jim Little, August 22, 2006).
2 USDA Profile 2009: Softwood Sawmills in the United States and Canada (Research Paper FPL-RP-659), October 2009, Table 1.
The emissions increases from all “affected” sources were calculated as the future projected actual emissions minus the baseline actual emissions, and then the demand growth exclusion was applied.

### Summary of PSD Analysis

<table>
<thead>
<tr>
<th></th>
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<td>15.65</td>
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<td>PM$_{10}$</td>
<td>8.65</td>
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<td>PM$_{2.5}$</td>
<td>6.52</td>
<td>NA</td>
<td>10</td>
<td>No</td>
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<td>SO$_2$</td>
<td>3.21</td>
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<td>VOC</td>
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<td>CO</td>
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<td>NO$_x$</td>
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<td>90.64</td>
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<tr>
<td>Lead</td>
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<td>0.6</td>
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<td>CO$_2$e</td>
<td>26,920</td>
<td>NA</td>
<td>75,000</td>
<td>No</td>
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Detailed emissions calculations and a summary of the PSD emissions analysis are shown below.
### Total Emissions Increase Compared to PSD Significance Rate (PM, PM$_{10}$, & PM$_{2.5}$)

<table>
<thead>
<tr>
<th>Emission Source</th>
<th>PM</th>
<th>PM$_{10}$</th>
<th>PM$_{2.5}$</th>
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<tr>
<td></td>
<td>Future Projected Actual (tpy)</td>
<td>Baseline Actual (tpy)</td>
<td>Actual with Demand Growth (tpy)</td>
</tr>
<tr>
<td>Sawmill Operations (SN-02)</td>
<td>8.40</td>
<td>4.66</td>
<td>5.96</td>
</tr>
<tr>
<td>Lumber Drying Kilns (SN-04 thru -06, SN-08, SN-30)</td>
<td>4.11</td>
<td>2.49</td>
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<td>Chipper Cyclone (SN-09)</td>
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<td>0.18</td>
<td>0.23</td>
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<tr>
<td>Shavings Cyclone (SN-10)</td>
<td>0.00</td>
<td>14.37</td>
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<tr>
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<td>10.09</td>
<td>7.66</td>
<td>0.00</td>
</tr>
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<td>Wood Fired Boiler No. 2 (SN-14)</td>
<td>10.09</td>
<td>6.33</td>
<td>7.65</td>
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<td>Shavings Cyclone (SN-16)</td>
<td>9.56</td>
<td>5.95</td>
<td>7.09</td>
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<tr>
<td>Gasoline Storage Tank (SN-18)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Diesel Storage Tank (SN-19)</td>
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<td></td>
</tr>
<tr>
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<td>17.59</td>
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<td>1.39</td>
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<td>8.40</td>
<td>5.08</td>
<td>6.48</td>
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<td>4.79</td>
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<td>Debarking Operations (IA)</td>
<td>0.48</td>
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<td>Sawdust Conveyors (IA)</td>
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<td>0.001</td>
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<tr>
<td>Batten Manufacturing Operations (IA)</td>
<td>0.22</td>
<td>0.12</td>
<td>0.16</td>
</tr>
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</table>

| Total Emissions Increase (Actual to Projected Actual with Demand Growth)** | 15.65 | 8.65 | 6.52 |
| Total PSD SER | 25 | 15 | 10 |

Emissions Increase = Future Projected Actual - Excludable Emissions - Baseline Actual, where Excludable Emissions = Actual with Demand Growth - Baseline Actual; Negative values are set to zero.

** Actual to Projected Actual with Demand Growth = $\sum$ Emission Increases
## Total Emissions Increase Compared to PSD Significance Rate (SO₂, VOC, & CO)

<table>
<thead>
<tr>
<th>Emission Source</th>
<th>SO₂</th>
<th>VOC</th>
<th>CO</th>
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</thead>
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<tr>
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<td>Lumber Drying Kilns (SN-04 thru -06, SN-08, SN-30)</td>
<td>1.56</td>
<td>0.99</td>
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<td>Chipper Cyclone (SN-09)</td>
<td>0.01</td>
<td>0.01</td>
<td>0.01</td>
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<td>Shavings Cyclone (SN-10)</td>
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<td>0.66</td>
<td>0.66</td>
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<td>5.50</td>
<td>3.02</td>
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<td>Wood Hog (IA)</td>
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<tr>
<td>Batten Manufacturing Operations (IA)</td>
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<tr>
<td><strong>Total Emissions Increase (Actual to Projected Actual with Demand Growth)</strong></td>
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<td><strong>129.98</strong></td>
<td><strong>61.02</strong></td>
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<td><strong>PSD SER</strong></td>
<td><strong>40</strong></td>
<td><strong>40</strong></td>
<td><strong>100</strong></td>
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<tr>
<td><strong>Total Emissions Increase &gt; PSD SER?</strong></td>
<td>NO</td>
<td>YES</td>
<td>NO</td>
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</table>

* Emissions Increase = Future Projected Actual - Excludable Emissions - Baseline Actual, where Excludable Emissions = Actual with Demand Growth - Baseline Actual; Negative values are set to zero.

** Actual to Projected Actual with Demand Growth = \( \sum \) Emission Increases
### Total Emissions Increase Compared to PSD Significance Rate (NOₓ, Lead, & CO₂e)

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<th>Emission Source</th>
<th>NOₓ</th>
<th>Lead</th>
<th>CO₂e</th>
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<td>(tpy)</td>
<td>(tpy)</td>
<td>(tpy)</td>
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<td>Sawmill Operations (SN-02)</td>
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<tr>
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<td>Gasoline Storage Tank (SN-18)</td>
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<td>Ash, Bark, Sawdust Storage Piles (SN-24)</td>
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<td>Planer Mill Shavings (SN-25)</td>
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<td>Debarking Operations (IA)</td>
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<tr>
<td>Batten Manufacturing Operations (IA)</td>
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<tr>
<td>Total Emissions Increase (Actual to Projected Actual with Demand Growth)**</td>
<td>90.64</td>
<td>0.01</td>
<td>26,920</td>
</tr>
<tr>
<td>** Actual to Projected Actual with Demand Growth = ( \sum ) Emission Increases</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

** Emissions Increase = Future Projected Actual - Excludable Emissions - Baseline Actual, where Excludable Emissions = Actual with Demand Growth - Baseline Actual; Negative values are set to zero.
** Actual to Projected Actual with Demand Growth = \( \sum \) Emission Increases

* Total Emissions Increase > PSD SER?**

<table>
<thead>
<tr>
<th>PSD SER</th>
<th>YES</th>
<th>NO</th>
<th>NO</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Total Emissions Increase &gt; PSD SER? **</th>
<th>YES</th>
<th>NO</th>
</tr>
</thead>
<tbody>
<tr>
<td>PSD SER</td>
<td>40</td>
<td>0.6</td>
</tr>
<tr>
<td></td>
<td>75,000</td>
<td>NO</td>
</tr>
</tbody>
</table>
Best Available Control Technology Analysis

Pursuant to the PSD regulations, a Best Available Control Technology (BACT) analysis is a required part of a PSD permit application for each new emission unit and for each affected emission unit that is undergoing a physical change or change in the method of operation. “A major modification shall apply best available control technology for each pollutant subject to regulation under the Act for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation of the unit.” [40 CFR 52.21(j)(3)]

The BACT analysis is a case-by-case analysis that takes into account technical feasibility, energy and environmental impacts, and cost. An integral part of the BACT analysis is a search of the US EPA’s RACT/BACT/LAER Clearinghouse (RBLC).

Because the only physical modifications addressed in this permit application are to Dry Kiln No. 3 and Dry Kiln No. 6, the kilns are the only sources included as part of the BACT analysis. Specifically, a BACT analysis was conducted for the Dry Kiln Nos. 1, 2, 3, 5, and 6 (SN-04, SN-05, SN-06, SN-08, and SN-30) for VOC emissions.

A BACT analysis for NOx was not conducted for any emission unit at the Waldo Mill. The net emissions increase of 90.64 tons per year of NOx, shown in the PSD analysis calculations above, is emitted from the existing boilers SN-13, SN-14 and SN-20. These boilers do not have a physical change nor change in method of operation in this project. The existing throughput limits for each boiler to not produce more than 1.2 MM lbs of steam per day and 350.4 MM lbs of steam in any 12-month period will remain unchanged.

The BACT analysis in this application follows the “top-down” approach. The following are the five basic steps of a “top-down” BACT analysis:

Step 1: Identify all control technologies
Step 2: Eliminate technically infeasible options
Step 3: Rank remaining control technologies by control effectiveness
Step 4: Evaluate most effective controls and document results
Step 5: Select BACT

Dry Kilns (SN-04, SN-05, SN-06, SN-08, and SN-30)

Volatile Organic Compounds (VOC)

Top-Down BACT Analysis
**Step 1: Identify All Control Technologies**

A list of control options was compiled based on general process knowledge and technical literature addressing lumber drying kilns. These options are:

- Incineration
- Adsorption
- Absorption
- Condensation
- Proper Operation of the Kiln

Additionally, a search of the RACT/BACL/LAER Clearinghouse (RBLC) was conducted to identify control technologies for the control of VOC emissions from lumber drying kilns utilizing indirect heat. The search was conducted to identify emission controls and rates for lumber drying kilns (Process Type: 30.800 – Wood Lumber Kilns) permitted since January 1, 2007.

**Step 2: Eliminate Technically Infeasible Options**

**Adsorption:** With adsorption, the VOC gases pass through a catalyst (an activated carbon bed is most common), and the VOCs are adsorbed in the catalyst. The cleaned gas is then released to the atmosphere. Because the exhaust gas from a lumber kiln (continuous or batch) has a high moisture content (at or near 100% relative humidity), the water molecules in the gas stream will compete with the hydrocarbon molecules in the gas stream for activated adsorption sites, and the sites will be filled with water. Therefore, adsorption is not a technically feasible technology for controlling VOC emissions from lumber kilns (continuous or batch).

**Absorption:** Absorption (or physisorption) is similar to adsorption (or chemisorptions) in that it employs a catalyst (again, an activated carbon bed is most common) for VOC removal; however, in absorption, the VOC that is being collected and removed from the gas stream actually penetrates and is absorbed into the catalyst. Similarly to adsorption, gas streams with a high moisture content are not a viable candidate for this type of control, because the water molecules in the gas stream will compete with the hydrocarbon molecules in the gas stream for activated adsorption sites, and the sites will be filled with water. Therefore, absorption is not a technically feasible technology for controlling VOC emissions from lumber kilns (continuous or batch).

**Condensation:** Condensation removes VOC from gas steam by cooling the stream to a low enough temperature that most contaminants are condensed as a liquid and then separated from the gas stream. Condensation is only effective when the gas stream can be cooled to a temperature where the vapor pressure of the gas stream is less than the VOC concentration. To reduce the vapor pressure of terpenes, the primary constituent of lumber kiln emissions, the temperature would need to be reduced to -40 °F. At this temperature, the unit would plug up with ice from the water vapor. Therefore, condensation is not a technically feasible technology for controlling VOC emissions from lumber kilns (continuous or batch).
Incineration/RTO: Regenerative Thermal Oxidizer (RTO) units use beds of ceramic stoneware or other heat exchange media to recover and store heat. The gas stream to be controlled passes through a heated bed before entering a combustion chamber. In the combustion chamber, the gas stream is heated by auxiliary fuel (typically natural gas) to an oxidation temperature of typically 1,500 °F or higher to achieve maximum VOC destruction. The exhaust gas temperature from a lumber kiln (continuous or batch) is between 150 °F and 200 °F, and the gas stream has a high moisture content, as discussed above. Essentially, all of the heat needed to achieve an oxidation temperature of 1,500 °F or greater would have to be supplied by the combustion of auxiliary fuel, which would generate additional air pollutants including NOx and CO. Due to the high moisture content and low exit temperature of the exhaust stream, an RTO would be technically infeasible technology for controlling VOC emissions from lumber kilns (continuous or batch).

As summarized in the RBLC search above, there are no facilities that currently utilize incineration to control VOC emissions at lumber drying kilns (continuous or batch).

Additionally, there have been no variations in the method of operation demonstrated that would result in a reduction in VOC emissions. For each of the above listed control technologies (including any combinations of these technologies or subsets), the air flows necessary for ventilation and air circulation required within the kiln to maintain appropriate temperature and moisture levels would be disrupted by the vacuum necessary to direct the air flow to a control device. This would also negatively affect the quality of the product exiting the kiln.

The remaining control option to be considered at the lumber drying kiln is proper design and operation of the system, which may include maintaining the unit at the proper temperature to avoid over-drying the lumber during the drying cycle. This is the option that the EPA has determined as BACT for all of the facilities listed in the RBLC.

**Step 3: Rank Remaining Control Technologies by Control Effectiveness**

There are currently no effective options for the control of VOC emissions due to the nature of lumber drying kiln operations. The only control option to be considered at the lumber drying kilns (continuous or batch) is proper design and operation.

**Step 4: Evaluate Most Effective Controls and Document Results**

The only effective option to be considered at the lumber drying kilns is proper design and operation. The RBLC provides a production based BACT limit for VOC ranging from 2.5 lb/MBF to 7.0 lb/MBF at facilities across the country.

**Step 5: Select BACT**

Stack testing for VOC is not feasible without extensive construction of temporary hoods and stacks; consequently, stack testing is considered to be unreliable. Thus, facilities rely on pilot test operations and the best available data from NCASI, the EPA, State regulatory agencies, and site specific knowledge of process. Using pilot test data is also considered an acceptable
methodology due to the fluctuations in VOC emissions from the wood being processed and the effects of temperature and humidity on the drying process. Deltic Waldo will utilize proper operation of the kilns and proposes to continue operating with the current 3.5 lb VOC/MBF limit as BACT.

The basis for achieving the BACT emission rate is proper maintenance and operation. Proper operation is defined as observing a proper drying schedule and a temperature selected based on moisture content of the lumber to be dried and the manufacturer’s specifications. Proper maintenance will also be completed on all kilns based on the manufacturer’s recommendations.

**PSD Modeling**

Originally, the facility requested that SN-30 Dry Kiln No. 6 be permitted to allow design flexibility to accommodate the kiln to be a steam-heated continuous kiln, a wood-fired, direct continuous kiln or a natural gas-fired, continuous kiln. During the processing of the application, the facility decided to install a steam-heated continuous kiln. This section includes information submitted with the original application. The information is still applicable as the selection of a steam-heated continuous kiln.

**NAAQS Analysis**

**Source Data**

The following tables list the NOx emission sources at the Waldo Mill, along with their location, emission rates, and stack parameters.

**Table 1. Waldo Mill NOx-Emitting Source Descriptions and Locations**

<table>
<thead>
<tr>
<th>SN</th>
<th>Source Description</th>
<th>UTM – E (m)</th>
<th>UTM – N (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SN-13</td>
<td>Wood-fired Boiler No. 1</td>
<td>471565</td>
<td>3688165</td>
</tr>
<tr>
<td>SN-14</td>
<td>Wood-fired Boiler No. 2</td>
<td>471569</td>
<td>3688165</td>
</tr>
<tr>
<td>SN-20</td>
<td>Wood-fired Boiler No. 3</td>
<td>471565</td>
<td>3688170</td>
</tr>
<tr>
<td>SN-30A</td>
<td>Dry Kiln No. 6 (Stack A)</td>
<td>471505</td>
<td>3688183</td>
</tr>
<tr>
<td>SN-30B</td>
<td>Dry Kiln No. 6 (Stack B)</td>
<td>471509</td>
<td>3688183</td>
</tr>
</tbody>
</table>

**Table 2. Waldo Mill NOx-Emitting Source Emission Rates and Stack Parameters**

<table>
<thead>
<tr>
<th>SN</th>
<th>Release Height (ft)</th>
<th>NOx Emission Rate (lb/hr)</th>
<th>Temp (°F)</th>
<th>Diameter (ft)</th>
<th>Exit Gas Velocity (ft/sec)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SN-13</td>
<td>60</td>
<td>18.83</td>
<td>400</td>
<td>3</td>
<td>66</td>
</tr>
<tr>
<td>SN-14</td>
<td>60</td>
<td>18.83</td>
<td>400</td>
<td>3</td>
<td>66</td>
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<tr>
<td>SN-20</td>
<td>60</td>
<td>18.83</td>
<td>400</td>
<td>3</td>
<td>66</td>
</tr>
<tr>
<td>SN-30A</td>
<td>45.5</td>
<td>1.95</td>
<td>170</td>
<td>2</td>
<td>35.4</td>
</tr>
<tr>
<td>SN-30B</td>
<td>45.5</td>
<td>1.95</td>
<td>170</td>
<td>2</td>
<td>35.4</td>
</tr>
</tbody>
</table>
Modeling Domain

A Tier 1 screening analysis was conducted using the facility sources as shown in Tables 1 and 2 above, with the AERMOD model set to regulatory defaults and assuming total conversion of nitrogen oxide (NO) to nitrogen dioxide (NO2). This analysis showed impacts from the Waldo Mill above the 7.5 µg/m³ significance level.

Appendix W guidance states, “For a NAAQS or PSD increments assessment, the modeling domain shall include all locations where the emissions of a pollutant from the new or modifying source(s) may cause a significant ambient impact” (p. 5217), but further states, “For NAAQS compliance demonstrations under PSD, use of the screening and preferred models for the pollutants listed in this subsection shall be limited to the near-field at a nominal distance of 50 km or less” (p. 5209). Based on the results of the significance modeling and both elements of the Appendix W guidance, the Waldo Mill used a 50 km radius as the modeling domain included in the modeling analysis, as addressed in the previously submitted modeling protocol. The point of origin for the determination of the 50 km radius is located at 471543 meters East and 3688173 m North, which is approximately the center of the process equipment at the Waldo Mill. A single model run was used to generate predicted ambient concentrations for both the annual and 1-hr averaging periods, so the 50 km modeling domain was used for both averaging periods.

Nearby Sources

Because screening modeling indicates that the Waldo Mill is predicted to have off-property ambient air impacts above the significance level, nearby sources of NOx emissions must be included in the model together with facility sources. Source information for nearby sources within the 50 km modeling domain were acquired from the ADEQ’s Envirowview tool and from the Louisiana Department of Environmental Quality’s ERIC database.

In March 2011, the United States Environmental Protection Agency (USEPA) released a memorandum titled “Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO2 National Ambient Air Quality Standard”, which provided guidance and clarification relative to a variety of issues related to the NO2 standard. Section 4 of this memorandum addresses the treatment of intermittent NO2 emission releases from sources (e.g., emergency generators, startup/shutdown events, etc.)

The USEPA states in this document that “the intermittent nature of the actual emissions associated with emergency generators and startup/shutdown in many cases, when coupled with the probabilistic form of the standard, could result in modeled impacts being significantly higher than actual impacts would realistically be expected to be for these emission scenarios.” To help alleviate this potential overestimation, the USEPA concluded that compliance demonstrations for the 1-hour NO2 standard be “based on emissions scenarios that can logically be assumed to be relatively continuous”, and that existing modeling guidelines provide discretion to exclude these intermittent emissions from 1-hour NO2 compliance demonstrations. The USEPA also clarifies that this exclusion applies to both project emissions and surrounding background sources. Based on the USEPA’s guidance, intermittent emissions from surrounding sources have been removed from the source inventory.
NO\textsubscript{x} to NO\textsubscript{2} Options

Models were run for an annual averaging time and a 1-hr averaging time with the non-default “Conversion of NO\textsubscript{x} to NO\textsubscript{2}” and the “1-Hr NO\textsubscript{2} NAAQS” options enabled.

In January 2010, the USEPA issued a new federal 1-hour NAAQS for NO\textsubscript{2}. Due to challenges that the new standard presents for facilities with significant levels of NO\textsubscript{x} emissions, it has become necessary to utilize the tiered screening methods in conducting ambient air impact analyses that the USEPA allows for in its “Guideline on Air Quality Models”. The tiered modeling methods consider the amount of NO\textsubscript{2} in the overall NO\textsubscript{x} release and/or the conversion of NO to NO\textsubscript{2} in the ambient air. More specifically, the Tier 1 methodology assumes a total conversion of NO to NO\textsubscript{2}, while the Tier 2 methodology assumes that only 75% of the NO released is converted to NO\textsubscript{2}, which is the annual national default value. The Tier 3 methodology allows for a detailed case-by-case analysis of the sources at the facility, which may include the site specific NO\textsubscript{2}/NO\textsubscript{x} ratios at each source. The use of a Tier 3 methodology, because it is case-by-case, requires approval by the USEPA before it can be used in an ambient air impact analysis. Prior to the promulgation of the 1-hour NAAQS for NO\textsubscript{2}, the use of the Tier 2 method typically provided an adequate adjustment, or reduction in NO\textsubscript{2} emissions, such that modeling results were below the annual NAAQS for NO\textsubscript{2}. In this analysis, Deltic Waldo used the Tier 3 PVMRM method to demonstrate compliance with the NAAQS.

Meteorological Data

A five year meteorological data set that includes data from 2007 through 2011 for Shreveport, Louisiana - specifically the Shreveport Regional Airport (Station #13957) - was used for the modeling analysis. This site was selected, because it provides the closest available surface and upper air data and is most representative of the weather conditions at the facility.

Background Data

The Waldo Mill used hourly NO\textsubscript{2} background data obtained from the USEPA’s AQS Data Mart. Specifically, monitoring data from Harrison County, Texas (#48_203, Site ID 2) for the years 2009-2011, because this is the closest data to Shreveport available through the AQS Data Mart. Monitoring data processed into the season by hour-of-day model input using the ProMoD v16148 tool developed by the Oklahoma Department of Environmental Quality was used. The three year averages of the highest 3\textsuperscript{rd} high values by season and hour-of-day were used in the Source Pathway of the model.

The Waldo Mill also used an existing ozone data set that has been used and approved by the ADEQ for previous modeling studies in close proximity to the Waldo Mill. This hourly ozone data was obtained from the USEPA’s AQS Data Mart for Shreveport, Louisiana (Site ID #220150008) for 2011. Initially, data from 2007 through 2011 was obtained, with the intention that the entire 5 year data set would be used. However, it was discovered that there were numerous gaps in the ozone data for the 2007 through 2010 data sets (e.g., numerous consecutive hours of data were completely missing from the data set). The AERMOD software contains a function with the intention of populating the missing hours of data; however, the software was not accurately filling the missing hours, but instead only placing data with the hours that existed
but did not have an ozone concentration associated with it. After numerous discussions with the software vendor and technical support, it was determined that it was an error within the software. The data for 2011 was examined, and it was found to not have the missing hours within the dataset. However, there were hours with no ozone concentration associated with it. In these cases, the average monthly ozone concentration from the 2007 through 2011 data set was used to replace any missing data (e.g., in the event that an hour of data was missing in February, the 5-year average ozone concentration for February was used in place of the null value). Because the ozone monitoring data is current, it was assumed to reflect current conditions in the region, and was therefore extrapolated for each year of the meteorological data used in the five year model.

**Land Use Classification**

The U.S. Geological Survey (USGS) National Land Cover Data for 2011 for the site was reviewed to determine the predominant land use for the area. Appendix W guidance states that a site should be classified as urban if industrial, commercial, and compact residential land use types account for 50% or more of the area within the 3 km radius. Because the area in the 3 km radius surrounding the Waldo Mill is predominantly “Forest & Woodland”, the area is “rural” for air dispersion modeling purposes.

**Terrain**

The model was run using the Elevated Terrain Height option. Elevations for the project were obtained using USGS National Elevation Dataset (NED) GEOTIFF digital terrain files. The NED files were processed using the AERMAP processor to generate source, building, and hill height values for the model.

**Building Downwash**

Each of the sources included in the model were evaluated in terms of their relation to nearby structures. Predominant structures at the facility were included as buildings in the model, and building downwash was integrated into the modeling analysis. The USEPA Building Point Input Program (BPIP) was used to determine the direction-specific downwash dimensions.

**In-Stack NO₂/NOₓ Ratios**

This analysis uses the USEPA default equilibrium NO₂/NOₓ value of 0.9 and the default In-Stack Ratio of 0.5 for individual NOₓ sources, where site-specific or USEPA source-specific NO₂/NOₓ in-stack ratios are not available. The Waldo Mill does not currently have any site-specific in-stack ratio data, but it may gather such data for use in Tier 3 modeling, if necessary.

The following table provides the surrounding sources included in the NO₂ modeling analyses, for which site-specific NO₂/NOₓ ratios were used rather than the default values:
### Table 5. Non-Default In-Stack NO₂/NOₓ Ratios for Nearby Sources

<table>
<thead>
<tr>
<th>Emission Source</th>
<th>In-Stack NO₂/NOₓ Ratio</th>
</tr>
</thead>
</table>
| White Rock Oil & Gas, LLC/MSPU:  
  • Compressor K-1E | 0.15<sup>2</sup> |
| Albemarle-West Plant:  
  • Boilers | 0.08<sup>1</sup> |
| American Fuel Cell/Coated Fabrics:  
  • Boilers | 0.08<sup>1</sup> |
| Bonanza Creek Energy Resources:  
  • Boiler  
  • Compressor Engines | 0.08<sup>1</sup>  
  0.15<sup>2</sup> |
| Macquarie Longview/Macedonia:  
  • Compressor Engine | 0.15<sup>2</sup> |
| Bonanza Creek/Dorcheat Gas:  
  • Compressor Engines | 0.15<sup>2</sup> |

<sup>1</sup> Average ratio provided for natural gas-fired boilers in EPA’s NO₂/NOₓ In-Stack Ratio Database  
<sup>2</sup> Average ratio provided for natural gas-fired compressors in EPA’s NO₂/NOₓ In-Stack Ratio Database

### Receptors

The Waldo Mill modeling analysis consists of receptors placed along the property boundary at 50 m spacing, along with a multi-tier grid with receptors placed at 50 m extending out 200 m, a spacing of 100 m out to 1 km, a spacing of 200 m out to 2 km, a spacing of 500 m out to 10 km, and a spacing of 1 km out to 50 km. The grid origin was set as the centroid of the sources polygon at (471543 m East and 3688173 m North). Receptors inside of the Waldo Mill’s fence line were removed from the model’s receptor grid.

### NO₂ Modeling Results

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Rate (lb/hr)</th>
<th>NAAQS Standard (µg/m³)</th>
<th>Averaging Time</th>
<th>Highest Concentration (µg/m³)</th>
<th>% of NAAQS</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO₂</td>
<td>60.39</td>
<td>100</td>
<td>Annual</td>
<td>27</td>
<td>27</td>
</tr>
<tr>
<td></td>
<td></td>
<td>188</td>
<td>1-hour</td>
<td>409&lt;sup&gt;1&lt;/sup&gt;</td>
<td>217</td>
</tr>
</tbody>
</table>

<sup>1</sup> Highest 8<sup>th</sup> high value

### NO₂ NAAQS (Annual)

The model resulted in a maximum annual concentration of 27 µg/m³ with background included, thus passing review against the 100 µg/m³ annual NO₂ NAAQS standard.
NO₂ NAAQS (1-hour)

For the one hour standard, the model resulted in a highest 8th high value of 409 µg/m³ with background included, which does not pass review against the 188 µg/m³ 1-hr NO₂ NAAQS standard. The model returned 128 instances where the predicted concentration exceeded the 1-hr NAAQS standard and an additional 71 instances where the predicted values were at or above 90% of the NAAQS standard. However, the USEPA states³ that, “in cases where modeled violations of the 1-hour NO₂ NAAQS are predicted, but the permit applicant can show that the NOₓ emissions increase from the proposed source will not have a significant impact at the point and time of any modeled violation, the permitting authority has discretion to conclude that the source’s emissions will not contribute to the modeled violation”.

The significance threshold for the 1-hr NO₂ standard is 7.5 µg/m³. To determine the Waldo Mill’s contribution to each predicted concentration, the model was set up to generate a NAAQS contribution file that reported every instance where there was a predicted 8th or greater high concentration at or above 169 µg/m³ (90% of the 188 µg/m³ standard) and each source group’s individual contribution, paired in time and space, to that total (see Appendix E for the complete Excel file detailing contributions for each facility).

The Waldo Mill’s maximum contribution (shown in Table 6 below) to any of the predicted ambient concentrations at 90% of the NAAQS or higher is 0.0138 µg/m³. This predicted concentration is well below the 7.5 µg/m³ threshold, which means that the Waldo Mill is not considered to contribute to any predicted concentrations at or above 90% of the NAAQS generated as a part of this modeling study. Note that the contributions predicted from nearby sources are more conservative than required by Appendix W, because permitted emission rates were used rather than actual emission rates, as is recommended in Table 8-2 of Appendix W. These higher rates were included in the model, because actual rates from neighboring facilities were not available to the Waldo Mill for this analysis, so the publically available permitted rates were used.

PSD Increment Analysis

The model resulted in a maximum annual concentration of 27 µg/m³ with background included. Background contributes a maximum annual concentration of 18 µg/m³, which indicates that the predicted maximum annual concentration excluding background is well below the Class II increment of 25 µg/m³.

Because increment consumption is determined by subtracting emissions occurring at the time of the baseline date from current emission rates and modeling the difference, the resulting concentrations would only decrease from what is reflected in the NAAQS analysis. Therefore, the NAAQS analysis for annual NO₂ emissions also demonstrates that the increment level of 25 µg /m³ has not been exceeded. Additionally, the maximum impact that the Waldo Mill has on the

increment (7.4 µg /m³) is located on the Waldo Mill’s property boundary. It is unlikely that any future growth will take place in close proximity to the Waldo Mill. Therefore, this project would not limit additional growth in the area and does not have an adverse effect on the industrial and economic development of the area. Because this project is an expansion and is not a new facility, alternative siting is not a viable option.

**Summary of Ozone Analysis**

Because Prevention of Significant Deterioration (PSD) review is required for volatile organic compounds (VOC) and nitrogen oxides (NOₓ) for this facility, and VOC to ozone, which has an established National Ambient Air Quality Standard (NAAQS), the PotlatchDeltic Waldo Mill (PotlatchDeltic) is required to consider potential impacts to ambient ozone concentrations as a result of the Project. Pursuant to 40 CFR Part 52.21, because the Project’s proposed emissions increase exceeds 100 tpy of VOC or NOₓ, the facility is required to prepare an ambient air impact analysis to ensure that the Project does not have an adverse impact on ambient ozone concentrations in the area. This analysis consists of two elements:

1. 40 CFR 52.21 requires that a preconstruction analysis of ambient air quality in the affected area be conducted for each pollutant undergoing PSD review using continuous air quality monitoring data collected for at least one year prior to submittal of the application for the proposed project. This requirement may be satisfied using data from existing monitoring stations operated by Federal, State, or local governmental agencies, provided that the area surrounding the existing monitors is representative of the facility site, and that the permitting authority agrees with the assessment of representativeness.

2. The proposed emissions increase from the Project must be evaluated to estimate its potential impact on ambient air quality to ensure that it does not cause or contribute to a predicted exceedance of the ozone NAAQS.

**Preconstruction Analysis of Ambient Air Quality**

Existing monitoring stations were evaluated as potential representative sites with respect to their proximity to PotlatchDeltic, the availability of continuous monitoring data, and the emissions profile and similarity of their airsheds to the PotlatchDeltic site. Three existing monitors are proposed as representative monitors, Caddo Valley, Arkansas (5-19-9991), Monroe, Louisiana (22-73-4), and Marshall, Texas (48-203-2), because they are located in close proximity to PotlatchDeltic, have continuous, available data, and are located in rural airsheds similar to PotlatchDeltic. Monitoring stations in Little Rock, Arkansas, and Shreveport, Louisiana, were also considered, but they were determined to be less representative of the PotlatchDeltic site, because they are located in urban rather than rural airsheds.

PotlatchDeltic proposes to use the most recent three years of continuous monitoring data from these three representative ambient air monitoring stations, as obtained from the United States Environmental Protection Agency (USEPA) AQS DataMart website, to estimate the pre-project background ozone concentration to satisfy the requirements of the PSD analysis in lieu of onsite preconstruction monitoring. A summary of the data is shown in the table below.
Potential Air Quality Impacts of Proposed Project

PotlatchDeltic is located in Columbia County, Arkansas, which is designated as in attainment for ozone. PotlatchDeltic must demonstrate that the proposed project will not cause or contribute to a predicted exceedance of the ozone NAAQS. Ozone analysis is complex because ozone is not emitted directly, but is a secondary pollutant that is formed in the atmosphere through photochemical reaction between VOC and NOx in the presence of sunlight. Modeling ozone directly requires complex chemical transport models, and the USEPA’s Guideline on Air Quality Models (Appendix W to 40 CFR Part 51, Section 5.2(e)) offers the following guidance:

“There is no preferred modeling system or technique for estimating ozone or secondary PM2.5 for specific source impacts or to assess impacts from multiple sources. For assessing secondary pollutant impacts from single sources, the degree of complexity required to assess potential impacts varies depending on the nature of the source, its emissions and the background environment. The EPA recommends a two-tiered approach where the first tier consists of using existing technically credible and appropriate relationships between emissions and impacts developed from previous modeling that is deemed sufficient for evaluating a source’s impacts. The second tier consists of more sophisticated case-specific modeling analyses”.

PotlatchDeltic proposes to satisfy compliance demonstration requirements for ozone under the PSD program by conducting the first tier technical analysis recommended in Appendix W using the guidance framework outlined in the USEPA’s guidance memorandum, Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program, published on December 2, 2016, by the USEPA’s Air Quality Assessment Division. In developing this framework, the USEPA conducted and compiled numerous photochemical grid model-based assessments of hypothetical single-source impacts on downwind ozone reflecting a range of release heights, emission rates, and geographic locations throughout the continental United States to develop the following relationship:

Modeled Emission Rate for Precursor (MERP) = Critical Air Quality Threshold\(^4\) * (Modeled emission rate from hypothetical source / Modeled air quality impact from hypothetical source)

\(^4\) The Critical Air Quality Threshold used is the USEPA-recommended NAAQS Significant Impact Level (SIL) concentration for 8-hour ozone of 1.0 ppb. Detail discussed in the USEPA Memorandum Guidance on Significant Impact

---

<table>
<thead>
<tr>
<th>Monitor Name</th>
<th>County</th>
<th>Site ID</th>
<th>Distance from Facility</th>
<th>4th Highest 8-Hour Ozone Concentration [ppm]</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>3-Year Average</th>
<th>Ozone NAAQS*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Caddo Valley, AR</td>
<td>Clark County</td>
<td>5-19-9991</td>
<td>100 km</td>
<td></td>
<td>0.060</td>
<td>0.055</td>
<td>0.058</td>
<td>0.058</td>
<td>0.070</td>
</tr>
<tr>
<td>Monroe, LA</td>
<td>Ouachita Parish</td>
<td>22-73-4</td>
<td>146 km</td>
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<td>0.060</td>
<td>0.061</td>
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</tr>
<tr>
<td>Marshall, TX</td>
<td>Harrison County</td>
<td>48-203-2</td>
<td>104 km</td>
<td></td>
<td>0.062</td>
<td>0.059</td>
<td>0.063</td>
<td>0.061</td>
<td></td>
</tr>
</tbody>
</table>

*Annual 4\(^{th}\)-highest daily maximum 8-hour concentration, averaged over 3 years
The ozone MERP values generated for each hypothetical source as a part of the analysis were summarized into the following table of Most Conservative (Lowest) Illustrative MERP Values (tons per year) by Precursor, Pollutant and Region.

<table>
<thead>
<tr>
<th>Precursor</th>
<th>Area</th>
<th>8-hr O3</th>
</tr>
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<tbody>
<tr>
<td>NOx</td>
<td>Central US</td>
<td>126</td>
</tr>
<tr>
<td></td>
<td>Eastern US</td>
<td>170</td>
</tr>
<tr>
<td></td>
<td>Western US</td>
<td>184</td>
</tr>
<tr>
<td>VOC</td>
<td>Central US</td>
<td>948</td>
</tr>
<tr>
<td></td>
<td>Eastern US</td>
<td>1,159</td>
</tr>
<tr>
<td></td>
<td>Western US</td>
<td>1,049</td>
</tr>
</tbody>
</table>

The USEPA guidance framework provides explanation and example calculations to illustrate that if emissions from the project source from each precursor requiring a PSD compliance demonstration are below the lowest (most conservative) O₃ MERP value shown in would be expected to be below the critical air quality threshold and would not be predicted to cause or contribute to a NAAQS exceedance.

For the PotlatchDeltic project, proposed emission increases of 129.98 tons per year of VOC and 90.64 tons per year are above the significant emission rates and require PSD review. Using the USEPA’s Tier 1 ozone analysis framework, the proposed increase of 129.98 tons per year of VOC is well below the VOC MERP for the Central United States of 948 tons per year, and the proposed increase of 90.64 tons per year of NOx is also below the NOx MERP for the Central United States of 126 tons per year. However, according to the USEPA guidance framework, “the NOx and VOC precursor contributions to 8-hour daily maximum O₃ are considered together to determine if the source’s air quality impact would exceed the critical air quality threshold. In such a case, the proposed emissions increase can be expressed as a percent of the lowest MERP for each precursor and then summed. A value less than 100% indicates that the critical air quality threshold will not be exceeded when considering the combined impacts of these precursors on 8-hour daily maximum O₃.”

For the PotlatchDeltic project, this value is calculated as,
90.64 tpy NO\textsubscript{x} from Project/126 tpy NO\textsubscript{x} MERP + 129.98 tpy VOC from Project/948 tpy NO\textsubscript{x} MERP = 0.72 + 0.14 = 0.86 * 100 = 86%

The combined contribution is less than 100%, which demonstrates that this project is expected to be below the ozone SIL and is not expected to cause or contribute to a violation of the NAAQS.

To look deeper into this analysis, PotlatchDeltic consulted Appendix A of the Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM\textsubscript{2.5} under the PSD Permitting Program to compare the facility to the closest modeled hypothetical source, which was located in Lincoln Parish, Louisiana (133 km from the Waldo Mill). The MERPs from this single hypothetical source are likely to be more representative of the meteorology and airshed of the facility than the aggregated Central United States value.

The hypothetical Lincoln Parish, Louisiana, source model resulted in the MERPs shown below, which are much higher than the lowest values in the Central region. This serves as further evidence that ozone formation resulting from the PotlatchDeltic project will not negatively impact ambient ozone concentrations in the vicinity of the facility.

\[
\text{VOC MERP} = \text{SIL} \times \left(\frac{\text{Modeled emission rate}}{\text{Modeled air quality impact}}\right) \\
= 1.0 \text{ ppb} \times \left(\frac{500 \text{ tpy}}{0.04 \text{ ppb}}\right) \\
= 12,500 \text{ tpy}
\]

\[
\text{NO}_x \text{ MERP} = \text{SIL} \times \left(\frac{\text{Modeled emission rate}}{\text{Modeled air quality impact}}\right) \\
= 1.0 \text{ ppb} \times \left(\frac{500 \text{ tpy}}{1.97 \text{ ppb}}\right) \\
= 254 \text{ tpy}
\]

As a final consideration, PotlatchDeltic reviewed the USEPA Air Emission Inventories data to compare project emissions to county-wide total emissions in Columbia County. In 2014 (the most recent data available from the USEPA), total VOC emissions from all sources (anthropogenic and biogenic sources) were 30,166 tons, and total NO\textsubscript{x} emissions from all sources were 1,444 tons. Proposed PotlatchDeltic project emissions represent a 0.4% increase in VOC and a 6% increase in NO\textsubscript{x} from the 2014 baseline data, which is unlikely to have a significant effect on ambient ozone concentrations in Columbia County.

For the above stated reasons, PotlatchDeltic requests that the Arkansas Department of Environmental Quality accept the ambient monitoring data from the representative monitors in lieu of onsite preconstruction monitoring and accept the facility’s analysis that this project is not predicted to cause or contribute to a violation of the ozone NAAQS.
Process Description

Sawmill

Logs are delivered to the log yard, where they are off-loaded and stored until needed by the mill. The logs are moved to the log decks by rubber-tired loaders, where they are mechanically conveyed through the debarking and sawing equipment. Pulp chips and sawdust produced during sawing operations are loaded into vans for transport to consumers. Rough, green lumber is sorted and stacked in packages on kiln sticks and stored on the yard until it is loaded into the drying kilns. Lumber packages are moved from the stacker to storage and to the dry kilns by rubber-tired loaders.

Dry Kilns

The Waldo Mill will operate three steam-heated continuous kilns and two steam-heated batch kilns that are all heated by steam produced by the boilers in the powerhouse. Steam from the boilers in the powerhouse heat the air circulating in the steam-heated kilns. In a high-temperature kiln, air is circulated through the lumber with the aid of several axial flow fans located along the center of the kiln. Vents in the roof of the kiln are designed to vent moisture-laden air and to maintain the desired wet bulb temperature within the kiln.

Naturally occurring VOCs are released from the wood throughout the drying cycle. VOC emissions vary considerably over the drying cycle, with no emissions during loading/unloading operations, and varying emission rates during the drying phase. Emissions are minimal at the start of the drying cycle when the kilns are being heated, because the exhaust vents are closed. Once the exhaust vents open, VOC emission concentrations and emission rates vary with exhaust flow.

Planer Mill

Dried lumber from the kilns is taken to the planer mill, where it is surfaced and trimmed before being packaged for shipment. Planer shavings are picked up at the planer and pneumatically conveyed to a cyclonic collector that discharges into a second cyclonic collector. This system also picks up material from the dry trim hog. Both the planer shavings and hogged dry trim are conveyed to the truck loading bin, where the material is stored for loading into vans for shipment to consumers.

Powerhouse

The powerhouse includes three bio-gas fired boilers (60 MMBtu/hr each) designed to produce 40,000 pounds per hour of 180 psig steam each. Each boiler is close-coupled to a biomass gasifier that consumes bark and green sawdust to produce bio-gas that is fired in the boilers.

Other Operations
The Waldo Mill maintains miscellaneous operations that support daily production activities. The miscellaneous operations include road traffic, maintenance operations, and the storage of gasoline, fuel oil, lubricating oil, and other liquids.

The Waldo Mill uses packaging materials, known as battens, to place under each package of finished lumber to allow for appropriate spacing in stacking and to assist forklifts in moving each package of finished lumber from one place to another. The battens are made at the Waldo Mill from scrap pieces at the Planer Mill. The batten line consists of a small chop saw, rip saw, and router. The finished battens are stacked and packaged by hand. This activity is conducted inside the planer mill and is not vented to the atmosphere.

Road traffic consists of haul road traffic and utility vehicle traffic. Logs, lumber, chips, sawdust, and shavings are shipped into and out of the facility by truck. Utility vehicles are used for loading and movement of materials throughout the facility. Maintenance operations include welding and cutting for metal fabrication and repair, as well as routine equipment and building upkeep.

**Regulations**

The following table contains the regulations applicable to this permit.

<table>
<thead>
<tr>
<th>Regulations</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Arkansas Air Pollution Control Code, Regulation 18, effective March 14, 2016</td>
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<tr>
<td>Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Regulation 19, effective March 14, 2016</td>
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<td>Regulations of the Arkansas Operating Air Permit Program, Regulation 26, effective March 14, 2016</td>
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<td>40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units</td>
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<td>40 CFR Part 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines</td>
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<td>40 CFR §52.21 Prevention of Significant Deterioration</td>
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**Emission Summary**

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.
<table>
<thead>
<tr>
<th>Source Number</th>
<th>Description</th>
<th>Pollutant</th>
<th>Emission Rates</th>
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</thead>
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<tr>
<td></td>
<td></td>
<td></td>
<td>lb/hr</td>
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<tr>
<td>2</td>
<td>Sawmill Operations</td>
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<tr>
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</tr>
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<td>Total HAPs</td>
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</tr>
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<td></td>
<td>Acetone</td>
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<td>Dry Kiln No. 2</td>
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<td></td>
<td></td>
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<td>25.5</td>
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<td></td>
<td>Methanol</td>
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Total Allowable Emissions

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<td>SO\textsubscript{2}</td>
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<td>VOC</td>
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Air Contaminants ***

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</thead>
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<td></td>
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<tr>
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<td>SO\textsubscript{2}</td>
<td>See Note*</td>
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<tr>
<td>VOC</td>
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<tr>
<td>CO</td>
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<td>Lead</td>
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<td>HCl</td>
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<tr>
<td>Methanol</td>
<td>5.13</td>
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<td>Acetone</td>
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Note: See Note* for PM\textsubscript{2.5}.
## EMISSION SUMMARY

<table>
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<td></td>
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<td>lb/hr  tpy</td>
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<td></td>
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<td></td>
<td>VOC</td>
<td>46.2 --</td>
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<td>Total HAP</td>
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<td>Acetone</td>
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<td>Total Annual Kiln Emissions (Dry Kiln No.1, Dry Kiln No.2, Dry Kiln No.3, Dry Kiln No.5, Dry Kiln No. 6)</td>
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<tr>
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<td>Chipper Cyclone</td>
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<td>0.2  0.4</td>
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<td></td>
<td>PM(_{10})</td>
<td>0.1  0.1</td>
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<td>Wood-fired Boiler #1 60 MMBTU/hr</td>
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<td>1.6  5.5</td>
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<td>VOC</td>
<td>4.4  15.4</td>
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<td></td>
<td>CO</td>
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<td>HCl</td>
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<td></td>
<td>PM</td>
<td>N/A</td>
</tr>
<tr>
<td>22</td>
<td>Shavings Cyclone</td>
<td>PM</td>
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</tr>
<tr>
<td></td>
<td></td>
<td>PM$_{10}$</td>
<td>0.2</td>
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<tr>
<td>24</td>
<td>Ash, Bark, and Sawdust Piles</td>
<td>PM</td>
<td>0.4</td>
</tr>
<tr>
<td></td>
<td></td>
<td>PM$_{10}$</td>
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</tr>
<tr>
<td></td>
<td></td>
<td>VOC</td>
<td>0.2</td>
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<tr>
<td>25</td>
<td>Planer Mill Shavings Handling</td>
<td>PM</td>
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</tr>
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<td></td>
<td></td>
<td>PM$_{10}$</td>
<td>0.1</td>
</tr>
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<td>27</td>
<td>Paved Roads</td>
<td>PM</td>
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<td></td>
<td>PM$_{10}$</td>
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<td>28</td>
<td>Feed Water Pump</td>
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<td></td>
<td>VOC</td>
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<tr>
<td></td>
<td></td>
<td>CO</td>
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<td></td>
<td></td>
<td>NO$_X$</td>
<td>1.1</td>
</tr>
<tr>
<td>29</td>
<td>Unpaved Roads</td>
<td>PM</td>
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</tr>
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<td></td>
<td></td>
<td>PM$_{10}$</td>
<td>0.5</td>
</tr>
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<td>30</td>
<td>Dry Kiln No. 6</td>
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<td></td>
<td></td>
<td>PM$_{10}$</td>
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</tr>
<tr>
<td></td>
<td></td>
<td>VOC</td>
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<td></td>
<td>Total HAP</td>
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</tr>
<tr>
<td></td>
<td></td>
<td>Acetone</td>
<td>N/A</td>
</tr>
</tbody>
</table>

*PM$_{2.5}$ limits are source specific, if required. Not all sources have PM$_{2.5}$ limits.*
**HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.

***Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.
SECTION III: PERMIT HISTORY

Permit #168-AI was issued to Deltic Farm and Timber Co., Inc. in September of 1973. This permit allowed for the installation of a wood waste incinerator.

Permit #697-A was issued to Deltic Farm and Timber Co., Inc. on January 28, 1983. This permit allowed for the installation of one waste wood fuel burner to supply heat for two drying kilns. It was estimated at the time of permit issuance that no significant increase in emissions of any pollutant would result from the installation of the new fuel burner.

Permit #697-AR-1 was issued on August 31, 1987. This permit allowed for the installation of a new drying kiln fired by a wood fuel burner similar to the one installed under Permit #697-A. In this permit, the opacity of the gases leaving the kilns was limited to 10% and the particulate matter emission rate was set at 2.5 pounds per hour.

Permit #697-AR-2 was issued on September 20, 1994. This permit allowed for the modification of the three existing kilns from direct heat to steam heat, the installation of two new steam heated drying kilns, and the installation of two new bio-gas fired boilers. This permit set emission limits of 308.9 tons per year of particulate matter, 12.2 tons per year of sulfur dioxide, 484.3 tons per year of volatile organic compounds (VOC), 249.6 tons per year of carbon monoxide, and 157.6 tons per year of oxides of nitrogen. Due to the level of VOC emissions, this permit classified this facility as a major source pursuant to 40 CFR 52.21 (PSD regulations).

Permit #697-AOP-R0 was issued to Deltic Timber Corporation on October 9, 1998. A recently installed planer mill and associated control equipment (SN-16 and SN-17) were permitted for the first time with the issuance of this permit. Emissions from the new planer mill are controlled by a new shavings cyclone and a new shavings bin. This permit continued to classify this facility as a major source pursuant to the PSD regulations.

Permit #697-AOP-R1 was issued on September 23, 1999, to Deltic Timber Corporation’s Waldo facility. The permitted throughputs at the two fuel tanks were increased with the issuance of this permit. The hourly emissions from the two tanks were based on emissions when they are being filled. No other changes took place with the issuance of this permit.

Permit #697-AOP-R1 was administratively amended on April 21, 2000 to correct typographical errors.

Permit #697-AOP-R2 was issued on September 11, 2000 as the third operating permit issued to Deltic Timber Corporation’s Waldo facility under Regulation 26. The modified permit was issued in order to clarify the applicability of the CEMS standards under 40 CFR Part 60 and the Department’s CEMS standards. The permit also clarified that a change in the published HAP emission factors for the two wood waste fired boilers would not constitute a violation of the permit. No physical changes or changes in the method of operation took place with the issuance of the permit.

Permit #697-AOP-R3 was issued on November 20, 2002 to address the replacement of the trim saw and accompanying optimizer associated with the sawmill operation (SN-02). Installation of
the new equipment did not result in changes to permitted emission limits or methods of operation.

Permit #697-AOP-R4 was issued on August 20, 2003. The permit was the first renewal issued to Deltic under the Title V program. Deltic proposed to install additional equipment with emissions that resulted in a significant modification. The additional equipment included a gang saw, a debarker, a lumber drying kiln (SN-21), and a steam generation project. In regards to the generation project, Deltic proposed to install either a natural gas-fired turbine (SN-20 A) or a wood-fired boiler and a gas turbine (SN-20 B). Deltic requested to increase total kiln throughput to 175 MMBF per year.

The increase in emissions required PSD netting to be performed for PM, PM$_{10}$, VOC, CO, and NO$_X$. The increase in these pollutants exceeded the PSD significance levels. The significance analysis indicated PM$_{10}$ and NO$_X$ required further modeling.

**PSD Summary**

The following tables summarize the selected BACT technologies and the emission limits associated with them. Limits are based on comparisons to similar units listed in RBLC and permitted in the state of Arkansas.

**BACT Technology and Limits for SN-20 A**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Control Technology</th>
<th>Emission Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO/VOC</td>
<td>Good Combustion Practices</td>
<td>CO: 50 ppmvd @ 15% O$_2$</td>
</tr>
<tr>
<td></td>
<td></td>
<td>VOC: 25 ppmvd @ 15% O$_2$</td>
</tr>
<tr>
<td>NO$_X$</td>
<td>Dry Low NO$_X$</td>
<td>14 ppmvd @ 15% O$_2$</td>
</tr>
<tr>
<td>PM/PM$_{10}$</td>
<td>Good Combustion Practices</td>
<td>0.0066 lb/MMBTU</td>
</tr>
</tbody>
</table>

**BACT Technology and Limits for SN-20 B**

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Control Technology</th>
<th>Emission Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO</td>
<td>Good Combustion Practices</td>
<td>0.475</td>
</tr>
<tr>
<td>NO$_X$</td>
<td>Overfire Air / Low NO$_X$</td>
<td>0.30</td>
</tr>
<tr>
<td></td>
<td>Combustion</td>
<td></td>
</tr>
<tr>
<td>PM/PM$_{10}$</td>
<td>ESP</td>
<td>0.08</td>
</tr>
<tr>
<td>VOC</td>
<td>Good Combustion Practices</td>
<td>0.07</td>
</tr>
</tbody>
</table>

Permit #697-AOP-R5 was issued on October 1, 2004 to allow installation of fourteen 1,000 gallon bulk oil storage tanks (Insignificant Activities List) and a cyclone (SN-22) used to collect shavings from the planermill and the dry trim hog. The Secondary Manufacturing operation (formerly Plantwide Condition #9) was re-designated as (SN-23). Emission estimates for the dry kilns were updated using NCASI TB 845, May 2002. Emissions from miscellaneous existing sources were also quantified. PM, PM$_{10}$, Acetone, and HAP emissions increased by 52.7 tpy, 24.3 tpy, 32.42 tpy, and 0.62 tpy, respectively. VOC emissions decreased by 215.2 tpy. Deltic
also informed ADEQ of their decision to not install the gas turbine (SN-20 B) or the proposed sixth drying kiln (SN-21).

Permit #697-AOP-R6 was issued on January 12, 2005 to allow expansion of the sawmill operation to achieve a maximum annual production 225 million board feet. The infeed was replaced by a sharp chain with a double length infeed. Other changes approved included an edger, a stacker, a package maker in the planer mill, a high speed debarker, a log bucking system, and modifications to the lumber flow decks. The five existing dry kilns were upgraded by adding new steam coils. An incorrect emission factor was used to estimate Acetone emissions for Permit #697-AOP-R5. Both PM and PM$_{10}$ emission increases were below their respective PSD significant emission increase, and they did not require further review. However, the increase in VOC emissions was greater than 40 tpy, and the modification of the drying kilns is subject to a full PSD analysis. The findings of the PSD analysis indicated there are no VOC control technologies for steam heated drying kilns.

Permit #697-AOP-R7 was issued on May 4, 2005 to give authorization to combust in the three boilers absorbent material that has been used to clean up oil/hydraulic spills. The absorbent material consists of wood chips, sawdust, and commercial products used to clean up oil spills. Permitted emissions will not increase because the absorbent material will be less than 0.1% of the fuel throughput limit. The permit was amended on February 14, 2006 to remove the lumber dip tank, an insignificant activity, from the permit.

Permit #697-AOP-R8 was issued on May 8, 2007 to incorporate the applicable requirements of 40 CFR Part 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters. Deltic also proposed to install a new blower at the Shavings Cyclone (SN-22) and requested permitted PM and PM$_{10}$ emission limits to be increased by 15.7 tpy and 6.2 tpy, respectively.

Permit #697-AOP-R9 was issued on January 12, 2009 as a Title V Renewal permit. Deltic reduced the emission estimate for the Planner Mill Shavings Handling (SN-25), increased VOC limits in order to maintain consistency in the rounding method used, quantified emissions from the haul roads (SN-27), and installed an emergency boiler feed water pump (SN-28). Deltic also added an existing fire pump and a new wood hog to the insignificant. Overall, permitted PM and PM$_{10}$ limits decreased by 16.9 tpy and 39.0 tpy, respectively, and permitted SO$_2$, VOC, and NO$_X$ limits increased by 0.1 tpy, 3.0 tpy, and 0.3 tpy, respectively.

Permit #697-AOP-R10 was issued on January 29, 2009 to incorporate changes that were agreed upon as a result of the public comment period for Permit #697-AOP-R9 that were inadvertently not incorporated.

Permit #697-AOP-R11 was issued on February 17, 2011 to install an additional blower at two boilers, Boiler #1 and Boiler #2 (SN-13 and SN-14). An increase in steam production or the amount of biomass burned was not requested. Therefore, permitted emission rates remain unchanged.
Permit #697-AOP-R12 was issued on January 4, 2012. Specific Condition #30 was revised to include clarification.

Permit #697-AOP-R13 was issued on October 18, 2013. A major modification was permitted that allowed the facility to increase production from 225 million board feet per year (MMBF/yr) to 285 MMBF/yr. Two existing steam heated batch kilns were converted to steam heated continuous kilns. An existing steam heated batch kiln was authorized to be demolished and replaced with a steam heated continuous kiln. A new planner mill was authorized in order to accommodate the increase in capacity from the kilns. Overall, permitted emissions increased by 104 tpy VOC, 1.1 tpy Acetone, 8.24 tpy HAPs, and decreased by 55.9 tpy PM and 28.5 tpy PM$_{10}$.

Permit #697-AOP-R14 was issued on August 6, 2014. The Title V permit was renewed. No physical changes or changes in method of operation were proposed by the facility. Certain annual limits were revised due to rounding. Overall, permitted emission decreased by 11.3 tpy PM and 10.9 tpy PM$_{10}$.

Permit #697-AOP-R15 was issued on April 27, 2015. Particulate emission limits were established for the kilns and requirements to test other pollutant emissions from the kilns were removed. Overall, permitted emissions limits increased by 7.5 tpy PM/PM$_{10}$.

Permit #697-AOP-R16 was issued on September 3, 2015. Two continuous kilns (SN-06 and SN-08) were modified to increase the maximum annual production capacity and the PM/PM$_{10}$ emission limits for all three continuous kilns (SN-06, SN-07, and SN-08) were revised. Overall, permitted emissions decreased by 3.5 tpy PM/PM$_{10}$.

Permit #697-AOP-R17 was issued on January 12, 2016. Boiler MACT applicable requirements for three wood-fired boilers (SN-13, SN-14 and SN-20) were incorporated into the permit. PM and PM$_{10}$ emissions were also revised. Overall, permitted emissions increased by 15.9 tpy PM and 4.2 tpy PM$_{10}$. 
SECTION IV: SPECIFIC CONDITIONS

SN-02

Sawmill Operation

Description

Logs are delivered to the mill yard where they are off-loaded and stored until needed by the mill. The logs are moved to the log decks by rubber-tired loaders and are mechanically conveyed through the debarking and sawing equipment. Pulp chips and sawdust produced in the sawing operations are loaded into trailer trucks for transport to consumers. Rough, green lumber is sorted and stacked in packages on kiln sticks and stored in the yard until loaded into a dry kiln. Lumber packages are moved from the stacker to storage and to the dry kilns by rubber-tired loaders.

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. Hourly emission rates are based on maximum capacity of the equipment. The permittee shall demonstrate compliance with annual rates through compliance with Plantwide Condition #7. [Reg.19.501 et seq. and 40 C.F.R. § 52 Subpart E]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM$_{10}$</td>
<td>2</td>
<td>4.8</td>
</tr>
</tbody>
</table>

2. The permittee shall not exceed the emission rates set forth in the following table. Hourly emission rates are based on maximum capacity of the equipment. The permittee shall demonstrate compliance with annual rates through compliance with Plantwide Condition #7. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>3.4</td>
<td>8.4</td>
</tr>
</tbody>
</table>
SN-04, SN-05, SN-06, SN-08 and SN-30

Dry Kilns #1, #2, #3, #5 and #6

Description

Dry Kilns Nos. 1 and 2 are steam heated batch kilns. Dry Kilns Nos. 3, 5 and 6 are steam heated continuous kilns. The kilns are scheduled to be operated 24 hours per day, 365 days per year, with the exception of the time required for loading, unloading, and maintenance. At this schedule, the kilns would be capable of drying more lumber than is actually produced at this facility. The excess drying capacity is required to produce the mix of products that the Waldo Mill offers.

Specific Conditions

3. The permittee shall not exceed the emission rates set forth in the following table. Hourly emission rates are based on maximum capacity of the equipment. The permittee shall demonstrate compliance with annual rates through compliance with Plantwide Condition #7.

<table>
<thead>
<tr>
<th>Source No.</th>
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<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>04</td>
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<td>--</td>
</tr>
<tr>
<td></td>
<td>VOC</td>
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<td>05</td>
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<td>--</td>
</tr>
<tr>
<td>06</td>
<td>PM$_{10}$</td>
<td>0.4</td>
<td>--</td>
</tr>
<tr>
<td></td>
<td>VOC</td>
<td>48.4</td>
<td>--</td>
</tr>
<tr>
<td>08</td>
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<td>--</td>
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<td></td>
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</tr>
<tr>
<td></td>
<td>VOC</td>
<td>48.4</td>
<td>--</td>
</tr>
<tr>
<td>Total Kiln Annual Emissions (Dry Kiln No.1, Dry Kiln No.2, Dry Kiln No.3, Dry Kiln No.5)</td>
<td>PM$_{10}$</td>
<td>--</td>
<td>11.2</td>
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<tr>
<td></td>
<td>VOC</td>
<td>--</td>
<td>543.2</td>
</tr>
</tbody>
</table>

Pollutant | Regulatory Citation
--- | ---
PM$_{10}$ | [Reg.19.501 et seq. and 40 C.F.R. § 52 Subpart E]
VOC | [Reg.19.901 et seq. and 40 C.F.R. § 52 Subpart E]

4. The permittee shall not exceed the emission rates set forth in the following table. Hourly emission rates are based on maximum capacity of the equipment. The permittee shall demonstrate compliance with annual rates through compliance with Plantwide Condition #7. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
<table>
<thead>
<tr>
<th>Source No.</th>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>04</td>
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</tr>
<tr>
<td></td>
<td>Methanol</td>
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<td>--</td>
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<td>--</td>
</tr>
<tr>
<td></td>
<td>Total HAPs</td>
<td>N/A</td>
<td>--</td>
</tr>
<tr>
<td></td>
<td>Acetone</td>
<td>N/A</td>
<td>--</td>
</tr>
<tr>
<td>05</td>
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<td></td>
<td>Methanol</td>
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<tr>
<td></td>
<td>Single HAP</td>
<td>1.40</td>
<td>--</td>
</tr>
<tr>
<td></td>
<td>Total HAPs</td>
<td>N/A</td>
<td>--</td>
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<tr>
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<td>Acetone</td>
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<td></td>
<td>Methanol</td>
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</tr>
<tr>
<td></td>
<td>Single HAP</td>
<td>2.65</td>
<td>--</td>
</tr>
<tr>
<td></td>
<td>Total HAPs</td>
<td>N/A</td>
<td>--</td>
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<td>Acetone</td>
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<td>08</td>
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<td></td>
<td>Total HAPs</td>
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<td>Acetone</td>
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<td></td>
<td>Total HAPs</td>
<td>--</td>
<td>43.13</td>
</tr>
<tr>
<td></td>
<td>Acetone</td>
<td>--</td>
<td>5.55</td>
</tr>
</tbody>
</table>

5. The permittee shall not exceed the emission rates set forth in the following table.
Compliance with this condition is based on drying southern yellow pine. [Reg.19.901 et seq. and 40 C.F.R. § 52 Subpart E]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>BACT Emission Limits</th>
</tr>
</thead>
<tbody>
<tr>
<td>VOC</td>
<td>3.5 lb/1,000 BF</td>
</tr>
</tbody>
</table>
SN-09

Chipper Cyclone

Description

Source SN-09 is the discharge from the cyclone collector that receives pulp chips that are pneumatically conveyed from the chipper. The chips are conveyed in a 14" diameter line by approximately 10,700 cfm of ambient air.

Specific Conditions

6. The permit allows the following maximum emission rates. Compliance with this condition is based on the maximum capacity of the equipment for hourly rate and 8,760 hours of operation for annual rate. [Reg.19.501 et seq. and 40 C.F.R. § 52 Subpart E]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM$_{10}$</td>
<td>0.1</td>
<td>0.1</td>
</tr>
</tbody>
</table>

7. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition is based on the maximum capacity of the equipment for hourly rate and 8,760 hours of operation for annual rate. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>0.2</td>
<td>0.4</td>
</tr>
</tbody>
</table>

8. The permittee shall not exceed 20% opacity from source SN-09 as measured by EPA Reference Method 9. [Reg.19.503 and 40 C.F.R. § 52 Subpart E]

9. Weekly observations of the opacity from SN 09 shall be conducted by a person trained, but not necessarily certified, in EPA Reference Method 9, and records shall be kept of these observations. If the permittee detects visible emissions greater than 20% opacity, the permittee must immediately take action to identify and correct the cause of the visible emissions. After implementing the corrective action, the permittee must document the source complies with the visible emissions requirements. The permittee shall maintain records of the cause of any visible emissions and the corrective action taken. The permittee must keep records of all observations onsite and make the records available to Department personnel upon request. [Reg. 19.705 and 40 C.F.R. § 52, Subpart E]
SN-16 and SN-22

Shavings Cyclones

Description

The shavings cyclone, SN 16, was installed in 1997. A third shavings cyclone, SN-22, was installed in 2004.

Dried lumber from the kilns is taken to the planermill, where it is surfaced and trimmed before being packaged for shipment. Planer shavings are then picked up at the planer by pneumatic conveying system and conveyed to a cyclonic collector (SN-16), that will discharge into a second pneumatic conveying system with a cyclonic collector (SN-22). The second system also picks up material from the dry trim hog and conveys both the planer shavings and the hogged dry trim to a truck loading bin, where the material is stored for loading into vans for shipment to the consumers.

Specific Conditions

10. The permit allows the following maximum emission rates. Compliance with this condition is based on the maximum capacity of the equipment for hourly rate and 8,760 hours of operation for annual rate. [Reg.19.501 et seq. and 40 C.F.R. § 52 Subpart E]

<table>
<thead>
<tr>
<th>Source No.</th>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>16</td>
<td>PM\textsubscript{10}</td>
<td>1.2</td>
<td>2.4</td>
</tr>
<tr>
<td>22</td>
<td>PM\textsubscript{10}</td>
<td>0.2</td>
<td>0.3</td>
</tr>
</tbody>
</table>

11. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition is based on the maximum capacity of the equipment for hourly rate and 8,760 hours of operation for annual rate. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

<table>
<thead>
<tr>
<th>Source No.</th>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>16</td>
<td>PM</td>
<td>4.7</td>
<td>9.6</td>
</tr>
<tr>
<td>22</td>
<td>PM</td>
<td>0.5</td>
<td>1.1</td>
</tr>
</tbody>
</table>

12. Weekly observations of the opacity from SN-16 and SN-22 shall be conducted by a person trained, but not necessarily certified, in EPA Reference Method 9, and records shall be kept of these observations. If the permittee detects visible emissions greater than 20% opacity, the permittee must immediately take action to identify and correct the cause of the visible emissions. After implementing the corrective action, the permittee must document the source complies with the visible emissions requirements. The permittee shall maintain records of the cause of any visible emissions and the corrective action taken. The permittee must keep records of all observations onsite and make the records
available to Department personnel upon request. [Reg. 19.705 and 40 C.F.R. § 52, Subpart E]
SN-13
Wood-fired Boiler #1

Description

Source SN-13 is a wood waste fired boiler with a heat input capacity of 60 MMBTU/hr. Because of the date of installation and the heat input capacity, this boiler is subject to the provisions of 40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units and 40 C.F.R. 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Particulate emissions are controlled by a multiclone and an electrostatic precipitator.

Specific Conditions

13. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition is based on the maximum heat input capacity of the equipment for the hourly rate for SO₂ and VOC and testing for PM<sub>10</sub>, CO, and NOₓ through compliance with Plantwide Condition #9. Compliance with the annual rate shall be demonstrated through compliance with Specific Conditions #15 and #16. [Reg.19.501 et seq. and 40 C.F.R. § 52 Subpart E]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM&lt;sub&gt;10&lt;/sub&gt;</td>
<td>2.2</td>
<td>7.5</td>
</tr>
<tr>
<td>SO₂</td>
<td>1.6</td>
<td>5.5</td>
</tr>
<tr>
<td>VOC</td>
<td>4.4</td>
<td>15.4</td>
</tr>
<tr>
<td>CO</td>
<td>29.9</td>
<td>104.5</td>
</tr>
<tr>
<td>NOₓ</td>
<td>18.9</td>
<td>66.0</td>
</tr>
<tr>
<td>Lead</td>
<td>5.69E-05</td>
<td>1.99E-04</td>
</tr>
</tbody>
</table>

14. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition is based on the maximum heat input capacity of the equipment for the hourly. Compliance with the annual rate shall be demonstrated through compliance with Specific Conditions #15 and #16. [Reg.19.501 et seq. and 40 C.F.R. § 52 Subpart E]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>2.9</td>
<td>10.1</td>
</tr>
<tr>
<td>HCl</td>
<td>0.49</td>
<td>1.71</td>
</tr>
<tr>
<td>Single HAP</td>
<td>0.49</td>
<td>1.71</td>
</tr>
<tr>
<td>Total HAPs</td>
<td>N/A</td>
<td>2.19</td>
</tr>
</tbody>
</table>

15. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition is based compliance with Specific Condition #20. [Reg.19.901 et seq. and 40 C.F.R. § 52 Subpart E]
Pollutant | BACT Emission Limits
--- | ---
VOC | 0.07 lb/MMBtu
 | 25 ppmvd @ 15% O₂
 | 4.2 lb/hr
 | 18.4 tpy

16. The permittee shall not produce more than 1.2 MM lbs of steam per day and 350.4 MM lbs of steam in any 12-month period at SN-13. Compliance with the annual rate shall be demonstrated through compliance with Specific Condition #17. Compliance with the daily rate shall be demonstrated through compliance with Specific Condition #21.g. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

17. The facility shall maintain monthly records that demonstrate compliance with the limits set in Specific Condition #16 which may be used by the Department for enforcement purposes. These records shall be updated by the fifteenth day of the month following the month to which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. An annual total and each individual month’s steam production data shall be submitted to the Department in accordance with General Provision #7. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

18. The permittee shall only combust wood waste and small amounts of oil soaked absorbent material used to clean up incidental, onsite oil spills. Absorbent material shall consist only of sawdust, wood chips, or commercially sold products made specifically for absorbing oil spills. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

19. The permittee shall operate the opacity monitor at SN-13 in compliance with the Department’s CEMS standards in Appendix C of this permit. Compliance or non-compliance with these standards does not necessarily constitute compliance or non-compliance with the NSPS CEMS standards. [Reg.19.703, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

Testing Requirements
(For Compliance with BACT Determination)

20. The permittee shall perform stack testing for VOC in accordance with Plantwide Condition #3 and EPA Reference Method 25A as found in 40 CFR Part 60, Appendix A to demonstrate compliance with the limits specified in Specific Condition #15. The testing shall be performed while SN-13 is operating at or above 90% maximum rated capacity. Testing shall be conducted every five years after the initial test in accordance with Plantwide Condition #3. [Reg.19.702 and 40 C.F.R. § 52 Subpart E]
21. SN-13 is subject to and shall comply with applicable provisions of 40 CFR Part 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. Applicable provisions of Subpart Dc include, but are not limited to, the following: [Reg. 19.304 and 40 C.F.R. § 60.40c]

a. The permittee shall not discharge to the atmosphere any gases from SN-13 that contain particulate matter in excess of 0.10 lb/ MMBTU. [Reg. 19.304 and 40 C.F.R. § 60.43c(b)(1)]

b. The permittee shall not exceed 20% opacity from source SN-13 as measured by EPA Reference Method 9 except for one 6-minute period per hour of not more than 27%. [Reg. 19.304 and 40 C.F.R. § 60.43c(c)]

c. The particulate matter and opacity standards apply at all times, except during periods of startup, shutdown, or malfunctions. [Reg. 19.304 and 40 C.F.R. § 60.43c(d)]

d. The permittee shall install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The records shall be maintained onsite for at least two years and made available to Department personnel upon request. [Reg. 19.304 and 40 C.F.R. §§ 60.48c(a) and 60.48c(i)]

e. The COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 (Appendix B to Part 60 – Performance Specifications). Compliance or non-compliance with the specifications set forth in Appendix B of 40 CFR Part 60 does not necessarily constitute compliance or non-compliance with the Department’s CEMS standards. [Reg. 19.304 and 40 C.F.R. § 60.47c (b)]

f. The permittee shall record any exceedances in opacity and submit excess emission reports for any excess emissions. The records shall be kept on site for at least two years. A report shall be submitted to the Department in accordance with General Provision #7.

Quarterly COMS excess emissions reports submitted pursuant to the ADEQ’s CEMS standards in Appendix C of the permit shall satisfy the requirements of this condition as long as the ADEQ quarterly report contains the same information as required by the NSPS. [Reg. 19.304 and 40 C.F.R. §§ 60.48c(c) and 60.48c (j)]

g. The permittee shall maintain daily records of the wood residue combusted in SN-13. These records shall be kept on site for at least two years and made available
to Department personnel upon request. [Reg. 19.304 and 40 C.F.R. §§ 60.48c(g) and 60.48c (i)]

CAM Requirements

22. SN-13 is subject to Compliance Assurance Monitoring and shall comply with all applicable provisions, including but not limited to: [Reg.19.703, 40 C.F.R. § 52 Subpart E, and 40 C.F.R. § 64.6]

   a. The permittee shall maintain a COMS at a location such that its readings are representative of the stack exhaust opacity. [Reg. 19.703, 40 C.F.R. § 52, Subpart E, and 40 C.F.R. § 64.6(c)(1)]

   b. The permittee shall maintain the indicator range on the COMS to make readings of opacities between 0% and 100%. [Reg. 19.703, 40 C.F.R. § 52, Subpart E, and 40 C.F.R. § 64.6(c)(1)]

   c. The permittee shall maintain a data acquisition system that completes a minimum of one cycle of opacity sampling and analyzing for each successive 10 second period. The data shall be used to determine six-minute average opacity readings from the COM. An alarm (visible and/or audible) shall be triggered when a six minute reading is over 20%. If more than one six minute reading exceeds the opacity limit in a one hour period the permittee shall take immediate corrective action. Records of any one hour period requiring corrective action shall be kept onsite, updated daily, and made available to Department personnel upon request. [Reg. 19.703, 40 C.F.R. § 52, Subpart E, and 40 C.F.R. § 64.6(c)(1)]

   d. The “rake-out” period shall be noted on the operator’s log and shall not be used to monitor compliance or to determine compliance with CAM requirements. [Reg. 19.703, 40 C.F.R. Part 52, Subpart E, and 40 C.F.R. § 64.6(c)(3)]

   e. The rake-out period is to be scheduled for the same specific time each day and shall be recorded. The Department shall be notified in advance and in writing of the schedule or any changes. The process of soot blowing, grate cleaning, ash raking, and refiring or any part thereof is considered one activity, and the time limit on this activity is 45 minutes. This activity shall not be performed more than once in any consecutive 8 hour period, and it shall not be performed more than three times in any consecutive 24 hour period. [Reg. 18.501(A)(4)]

NESHAP Subpart DDDDD Requirements for SN-13

23. SN-13 is an affected source subject to the requirements of 40 C.F.R. 63, Subpart DDDDD – *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*. For the purpose of the subpart the boiler is designated as an existing boiler that belongs to the stoker/sloped grate/other units designed to burn wet biomass/bio-based solid subcategory.
The permittee shall comply with the subpart no later than January 31, 2016, except as provided in § 63.6(i). The applicable requirements include, but are not limited to the following: [Reg.19.304 and 40 C.F.R. § 63, Subpart D]

a. The permittee shall not allow emissions to exceed the following emission limits, except during periods of startup and shutdown. The permittee shall demonstrate compliance with these limits through performance testing except where the subpart provides for fuel analysis to be used in lieu of performance testing. [Reg.19.304 and 40 C.F.R. § 63.7500(a)(1)]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Limits (lb per MMBtu of heat input)</th>
<th>Alternative Output-based Limits (lb per MMBtu of steam output)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HCl</td>
<td>2.2E-02</td>
<td>2.5E-02</td>
</tr>
<tr>
<td>Mercury</td>
<td>5.7E-06</td>
<td>6.4E-06</td>
</tr>
<tr>
<td>CO</td>
<td>1,500 ppvd @ 3% O₂</td>
<td>1.4</td>
</tr>
<tr>
<td>Filterable PM</td>
<td>3.7E-02</td>
<td>4.3E-02</td>
</tr>
</tbody>
</table>

b. As an alternative to complying with limit for Filterable PM in the preceding condition, the permittee shall not allow the total selected metals emissions to exceed the following emission limits, except during periods of startup and shutdown. The permittee shall demonstrate compliance with these limits through performance testing except where the subpart provides for fuel analysis to be used in lieu of performance testing.

*Total selected metals (TSM)* means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

[Reg.19.304 and 40 C.F.R. § 63.7500(a)(1)]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Limits (lb per MMBtu of heat input)</th>
<th>Alternative Output-based Limits (lb per MMBtu of steam output)</th>
</tr>
</thead>
<tbody>
<tr>
<td>TSM</td>
<td>2.4E-04</td>
<td>2.8E-04</td>
</tr>
</tbody>
</table>

c. The permittee shall comply with all applicable work practice standards including but not limited to the standards identified in the following table. [Reg.19.304 and 40 C.F.R. § 63.7500(a)(1)]
<table>
<thead>
<tr>
<th>If your unit is...</th>
<th>You must meet the following...</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater</td>
<td>Conduct a tune-up of the boiler or process heater every 5 years as specified in §63.7540.</td>
</tr>
<tr>
<td>4. An existing boiler or process heater located at a major source facility, not including limited use units</td>
<td>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. 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 a. to e. appropriate for the on-site technical hours listed in §63.7575:</td>
</tr>
<tr>
<td></td>
<td>a. A visual inspection of the boiler or process heater system.</td>
</tr>
<tr>
<td></td>
<td>b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.</td>
</tr>
<tr>
<td></td>
<td>c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.</td>
</tr>
<tr>
<td></td>
<td>d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.</td>
</tr>
<tr>
<td>NESHAP Subpart DDDDD Table 3 Applicable Work Practice Standards</td>
<td></td>
</tr>
<tr>
<td>---------------------------------------------------------------</td>
<td></td>
</tr>
<tr>
<td><strong>If your unit is . . .</strong></td>
<td><strong>You must meet the following . . .</strong></td>
</tr>
<tr>
<td></td>
<td>e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified.</td>
</tr>
<tr>
<td></td>
<td>f. A list of cost-effective energy conservation measures that are within the facility's control.</td>
</tr>
<tr>
<td></td>
<td>g. A list of the energy savings potential of the energy conservation measures identified.</td>
</tr>
<tr>
<td></td>
<td>h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.</td>
</tr>
<tr>
<td>5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup</td>
<td>You must operate all CMS during startup. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, and liquefied petroleum gas.</td>
</tr>
<tr>
<td></td>
<td>If you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose.</td>
</tr>
<tr>
<td></td>
<td>You must comply with all applicable emission limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of startup, as specified in §63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in §63.7555.</td>
</tr>
</tbody>
</table>
NESHAP Subpart DDDDD Table 3 Applicable Work Practice Standards

<table>
<thead>
<tr>
<th>If your unit is . . .</th>
<th>You must meet the following . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown</td>
<td>You must operate all CMS during shutdown. While firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR.</td>
</tr>
</tbody>
</table>

You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in §63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in §63.7555.

d. The permittee shall comply with each applicable operating limit including but not limited to the standards identified in the following table. [Reg.19.304 and 40 C.F.R. § 63.7500(a)(2)]

NESHAP Subpart DDDDD Table 4 Applicable Operating Limits

<table>
<thead>
<tr>
<th>When complying with a numerical emission limit using . . .</th>
<th>You must meet these operating limits . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>4. Electrostatic precipitator control on units not using a PM CPMS</td>
<td>a. This option is for boilers and process heaters that operate dry control systems (i.e., an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).</td>
</tr>
<tr>
<td>7. Fuel analysis</td>
<td>Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to §63.7530(c)(1), (2) and/or (3) is less than the applicable emission limits.</td>
</tr>
<tr>
<td>8. Performance testing</td>
<td>For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test.</td>
</tr>
</tbody>
</table>
e. The permittee shall demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. The permittee may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to §63.7530(c) is less than the applicable emission limit. Otherwise, the permittee shall demonstrate compliance for HCl, mercury, or TSM using performance testing. [Reg.19.304 and 40 C.F.R. § 63.7505(c)]

f. The permittee shall develop a site-specific monitoring plan according to the requirements in § 63.7505 (d)(1) through (4) for the use of any CEMS, COMS, or CPMS. [Reg.19.304 and 40 C.F.R. § 63.7505(d)]

g. For each boiler or process heater that is required or that the permittee elects to demonstrate compliance with any of the applicable emission limits in paragraphs (a) and (b) through performance testing, the initial compliance requirements include all the following: [Reg.19.304 and 40 C.F.R. § 63.7510(a)]

i. The permittee shall conduct all performance tests according to §63.7(c), (d), (f), and (h). The permittee shall also develop a site-specific stack test plan according to the requirements in §63.7(c). The permittee shall conduct all performance tests under such conditions as the Administrator specifies based on the representative performance of each boiler or process heater for the period being tested. Upon request, the permittee shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. [Reg.19.304 and 40 C.F.R. § 63.7520(a)]

ii. The permittee shall conduct each performance test according to Table 5 of Subpart DDDDD. [Reg.19.304 and 40 C.F.R. § 63.7520(b)]

| NESHAP Subpart DDDDD Table 5 Applicable Performance Test Requirements* |
|---|---|
| To conduct a performance test for the following pollutant... | You must conduct the performance test using the following test method(s)... |
| To conduct a performance test for the following pollutant... | You must conduct the performance test using the following test method(s)... |
| 1. Filterable PM** | Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6. |
| 2. TSM** | Method 29 at 40 CFR part 60, appendix A-8. |
To conduct a performance test for the following pollutant...
3. Hydrogen chloride**
   Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8.
4. Mercury**
   Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784.
5. CO
   Method 10 at 40 CFR part 60, appendix A-4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.

* This table only shows the pollutant specific test method(s) to be used. See Subpart DDDDD Tables 2 and 5 for additional required sampling procedures, minimum applicable sampling times and test methods.
** Subpart DDDDD Table requires the measured emissions concentration to be converted to pounds per MMBtu emission rates using Method 19 F-factor methodology at 40 CFR part 60, appendix A-7.

iii. The permittee shall conduct each performance test under the specific conditions listed in Tables 5 and 7 to Subpart DDDDD. The permittee shall conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if the permittee opts to comply with the TSM alternative standard and the permittee must demonstrate initial compliance and establish the operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, the permittee shall comply with the operating limit for operating load conditions specified in Table 4 to Subpart DDDDD. [Reg.19.304 and 40 C.F.R. § 63.7520(c)]

<table>
<thead>
<tr>
<th>NESHAP Subpart DDDDD Table 7 Applicable Requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>If you have an applicable emission limit for . . .</td>
</tr>
<tr>
<td>And your operating limits are based on . . .</td>
</tr>
<tr>
<td>You must . . . Using . . .</td>
</tr>
<tr>
<td>According to the following requirements</td>
</tr>
</tbody>
</table>

49
<table>
<thead>
<tr>
<th>NESHAP Subpart DDDDD Table 7 Applicable Requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>If you have an applicable emission limit for . . .</td>
</tr>
<tr>
<td>4. Carbon monoxide</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>5. Any pollutant for which compliance is demonstrated by a performance test</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
</tbody>
</table>
iv. The permittee shall conduct a minimum of three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Table 2 to Subpart DDDDD. [Reg.19.304 and 40 C.F.R. § 63.7520(d)]

v. To determine compliance with the emission limits, the permittee shall use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A-7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates. [Reg.19.304 and 40 C.F.R. § 63.7520(e)]

vi. If measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), the permittee shall use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level. [Reg.19.304 and 40 C.F.R. § 63.7520(f)]

vii. The permittee shall conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to Subpart DDDDD. For each boiler or process heater that burns a single type of fuel, the permittee is not required to conduct a fuel analysis for each type of fuel burned in the boiler or process heater according to §63.7521 and Table 6. [Reg.19.304 and 40 C.F.R. § 63.7510(a)(2)]

<table>
<thead>
<tr>
<th>NESHAP Subpart DDDDD Table 6 Applicable Fuel Analysis Requirements *</th>
</tr>
</thead>
<tbody>
<tr>
<td>To conduct a fuel analysis for the following pollutant . . .</td>
</tr>
<tr>
<td>You must measure the pollutant concentration in the fuel using . . .</td>
</tr>
<tr>
<td>1. Mercury</td>
</tr>
<tr>
<td>ASTM D6722a (for coal), EPA SW-846-7471Ba (for solid samples), or EPA SW-846-7470Aa (for liquid samples), or equivalent.</td>
</tr>
<tr>
<td>2. HCl</td>
</tr>
<tr>
<td>EPA SW-846-9250a, ASTM D6721a, ASTM D4208a (for coal), or EPA SW-846-5050a or ASTM E776a (for solid fuel), or EPA SW-846-9056a or SW-846-9076a (for solids or liquids) or equivalent.</td>
</tr>
</tbody>
</table>
NESHAP Subpart DDDDD Table 6 Applicable Fuel Analysis Requirements *

<table>
<thead>
<tr>
<th>To conduct a fuel analysis for the following pollutant . . .</th>
<th>You must measure the pollutant concentration in the fuel using . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>4. TSM for solid fuels</td>
<td>ASTM D3683a, or ASTM D4606 a, or ASTM D6357a or EPA 200.8a or EPA SW-846-6020a, or EPA SW-846-6020Aa, or EPA SW-846-6010Ca, EPA 7060a or EPA 7060Aa (for arsenic only), or EPA SW-846-7740a (for selenium only).</td>
</tr>
</tbody>
</table>

* This table only shows the pollutant specific measurement method(s) to be used. See Subpart DDDDD Table 6 for the complete required sample collection, analysis, measurement, and emission calculation procedures.

viii. The permittee shall establish operating limits for each boiler according to §63.7530 and Table 7 to Subpart DDDDD. [Reg.19.304 and 40 C.F.R. § 63.7510(a)(3)]

A. The permittee shall maintain opacity to less than or equal to 10 percent opacity (daily block average). [Reg.19.304 and 40 C.F.R. § 63.7500(a)(2)]

ix. For a minimum oxygen level (CO performance test), if the permittee conducts multiple performance tests, the permittee must set the minimum oxygen level at the lower of the minimum values established during the performance tests. [Reg.19.304 and 40 C.F.R. § 63.7530(b)(4)(vii)]

x. The permittee shall include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to Subpart DDDDD and is an accurate depiction of the facility at the time of the assessment. [Reg.19.304 and 40 C.F.R. § 63.7530(c)]

xi. The permittee shall submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e). Reg.19.304 and 40 C.F.R. § 63.7530(g)]

xii. The permittee shall conduct CMS performance evaluations according to §63.7525. [Reg.19.304 and 40 C.F.R. § 63.7510(a)(3)]

xiii. The permittee shall install, operate, and maintain an oxygen analyzer system, as defined in §63.7575, before January 1, 2016. [Reg.19.304 and 40 C.F.R. § 63.7525(a)]

A. The permittee shall operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart. [Reg.19.304 and 40 C.F.R. § 63.7525(a)(7)]
xiv. The permittee shall install, operate, certify and maintain each COMS by January 31, 2016 and according to the following procedures: [Reg.19.304 and 40 C.F.R. § 63.7525(c)]

A. Each COMS must be installed, operated, and maintained according to Performance Specification 1 at appendix B to part 60 of this chapter. [Reg.19.304 and 40 C.F.R. § 63.7525(c)(1)]

B. The permittee shall conduct a performance evaluation of each COMS according to the requirements in §63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter. [Reg.19.304 and 40 C.F.R. § 63.7525(c)(2)]

C. 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. [Reg.19.304 and 40 C.F.R. § 63.7525(c)(3)]

D. The COMS data must be reduced as specified in §63.8(g)(2). [Reg.19.304 and 40 C.F.R. § 63.7525(c)(4)]

E. The permittee shall include in the 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. [Reg.19.304 and 40 C.F.R. § 63.7525(c)(5)]

Note: 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 40 C.F.R. § 60, Appendix B and that meet the requirements of §63.7525. [§63.7505 (d)(1)]. The permittee has stated that the COMS located at this facility are existing and operated according to the performance specifications under 40 C.F.R. § 60, Appendix B.

F. The permittee shall operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of §63.8(e). The permittee shall identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control and data are not available for a
required calculation constitutes a deviation from the monitoring requirements. [Reg.19.304 and 40 C.F.R. § 63.7525(c)(6)]

Note: Although the permittee is not required to develop and submit a site-specific monitoring plan for the COMS, the permittee must comply with the other provisions of Specific Condition #25(g)(xiv)(F).

G. The permittee shall determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control. [Reg.19.304 and 40 C.F.R. § 63.7525(c)(7)]

h. At a minimum the permittee shall monitor and collect data according the site-specific monitoring plan and the following: [Reg.19.304 and 40 C.F.R. § 63.7535]

i. The permittee shall operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater is operating and compliance is required, except for periods of monitoring system malfunctions or out of control periods (see §63.8(c)(7)), and required monitoring system quality assurance or 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. The permittee is 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. [Reg.19.304 and 40 C.F.R. § 63.7535(b)]

ii. The permittee may not use data recorded 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 control activities in data averages and calculations used to report emissions or operating levels. The permittee shall record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. The permittee shall use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system. [Reg.19.304 and 40 C.F.R. § 63.7535(c)]
iii. Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods when the monitoring system is out of control as specified in the site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. The permittee shall calculate monitoring results using all other monitoring data collected while the process is operating. The permittee shall report all periods when the monitoring system is out of control in the annual report. [Reg.19.304 and 40 C.F.R. § 63.7535(d)]

j. The permittee shall demonstrate continuous compliance with each emission limit in Table 2, the work practice standards in Table 3, and the operating limits in Table 4 to Subpart DDDDD that apply according to the methods specified in Table 8 and as follows: [Reg.19.304 and 40 C.F.R. § 63.7540(a)]

<table>
<thead>
<tr>
<th>NESHAP Subpart DDDDD Table 8 Demonstrating Continuous Compliance</th>
</tr>
</thead>
<tbody>
<tr>
<td>If you must meet the following operating limits or work practice standards . . .</td>
</tr>
<tr>
<td>1. Opacity</td>
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<tr>
<td></td>
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<td>8. Emission limits using fuel analysis</td>
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<td></td>
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<tr>
<td>9. Oxygen content</td>
</tr>
</tbody>
</table>
### NESHAP Subpart DDDDD Table 8 Demonstrating Continuous Compliance

<table>
<thead>
<tr>
<th>If you must meet the following operating limits or work practice standards . . .</th>
<th>You must demonstrate continuous compliance by . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>§63.7525(a)(2).</td>
</tr>
<tr>
<td></td>
<td>b. Reducing the data to 30-day rolling averages; and</td>
</tr>
<tr>
<td></td>
<td>c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent CO performance test.</td>
</tr>
</tbody>
</table>

### 10. Boiler or process heater operating load

<table>
<thead>
<tr>
<th></th>
<th>a. Collecting operating load data or steam generation data every 15 minutes.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>b. Maintaining the operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test according to §63.7520(c).</td>
</tr>
</tbody>
</table>

i. The permittee shall conduct a tune-up of the boiler every 5 years as specified in § 63.7540 (a)(10)(i) through (vi) to demonstrate continuous compliance. The permittee may delay the required burner inspection until the next scheduled or unscheduled unit shutdown, but the permittee shall inspect each burner at least once every 72 months. If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup. [Reg.19.304 and 40 C.F.R. § 63.7540(a)(12) and (13)]

ii. Following the date on which the initial compliance demonstration is completed or is required to be completed under §§63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of Subpart DDDDD except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests. [Reg.19.304 and 40 C.F.R. § 63.7540(a)(1)]

iii. The permittee shall report each instance in which the permittee did not meet each applicable emission limit and operating limit in Tables 2, 3, and 4 to Subpart DDDDD. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in §63.7550. [Reg.19.304 and 40 C.F.R. § 63.7540(b)]

iv. As specified in §63.7550(c), the permittee shall keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels
burned would result in either of the following: [Reg.19.304 and 40 C.F.R. § 63.7540(a)(1)]

A. Lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if the permittee demonstrates compliance through fuel analysis. [Reg.19.304 and 40 C.F.R. § 63.7540(a)(2)(i)]

B. Lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing. [Reg.19.304 and 40 C.F.R. § 63.7540(a)(2)(ii)]

v. If the permittee demonstrates compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and to burn a new type of solid or liquid fuel, the permittee shall recalculate the HCl emission rate using Equation 12 of §63.7530 according to the following paragraphs. The permittee is not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). The permittee may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate. [Reg.19.304 and 40 C.F.R. § 63.7540(a)(3)]

A. The permittee shall determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or the permittee’s own fuel analysis, according to the provisions in the site-specific fuel analysis plan developed according to §63.7521(b). [Reg.19.304 and 40 C.F.R. § 63.7540(a)(3)(i)]

B. The permittee shall determine the new mixture of fuels that will have the highest content of chlorine. [Reg.19.304 and 40 C.F.R. § 63.7540(a)(3)(ii)]

C. The permittee shall recalculate the HCl emission rate from the boiler or process heater under these new conditions using Equation 12 of §63.7530. The recalculated HCl emission rate must be less than the applicable emission limit. [Reg.19.304 and 40 C.F.R. § 63.7540(a)(3)(iii)]

vi. If the permittee demonstrates compliance with an applicable HCl emission limit through performance testing and the permittee plans to burn a new type of fuel or a new mixture of fuels, the permittee shall recalculate the maximum chlorine input using Equation 7 of §63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of §63.7530 are greater than the maximum chlorine input level established during the previous performance test, then the permittee shall conduct a new
performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. The permittee shall also establish new operating limits based on this performance test according to the procedures in §63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, the permittee is not required to conduct fuel analyses for and include the fuels described in §63.7510(a)(2)(i) through (iii). [Reg.19.304 and 40 C.F.R. § 63.7540(a)(4)]

vii. If the permittee demonstrates compliance with an applicable mercury emission limit through fuel analysis, and the permittee plans to burn a new type of fuel, the permittee shall recalculate the mercury emission rate using Equation 13 of §63.7530 according to the procedures specified in the following paragraphs. The permittee is not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). The permittee may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate. [Reg.19.304 and 40 C.F.R. § 63.7540(a)(5)]

A. The permittee shall determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or the permittee’s own fuel analysis, according to the provisions in the site-specific fuel analysis plan developed according to §63.7521(b). [Reg.19.304 and 40 C.F.R. § 63.7540(a)(5)(i)]

B. The permittee shall determine the new mixture of fuels that will have the highest content of mercury. [Reg.19.304 and 40 C.F.R. § 63.7540(a)(5)(ii)]

C. The permittee shall recalculate the mercury emission rate from the boiler or process heater under these new conditions using Equation 13 of §63.7530. The recalculated mercury emission rate must be less than the applicable emission limit. [Reg.19.304 and 40 C.F.R. § 63.7540(a)(5)(iii)]

viii. If the permittee demonstrates compliance with an applicable mercury emission limit through performance testing, and the permittee plans to burn a new type of fuel or a new mixture of fuels, the permittee shall recalculate the maximum mercury input using Equation 8 of §63.7530. If the results of recalculating the maximum mercury input using Equation 8 of §63.7530 are higher than the maximum mercury input level established during the previous performance test, then the permittee shall conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the
mercury emissions do not exceed the emission limit. The permittee shall also establish new operating limits based on this performance test according to the procedures in §63.7530(b). The permittee is not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). The permittee may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate. [Reg.19.304 and 40 C.F.R. § 63.7540(a)(6)]

ix. If the permittee demonstrates compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, the permittee shall recalculate the TSM emission rate using Equation 14 of §63.7530 according to the procedures specified in the following paragraphs. The permittee is not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). The permittee may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate. [Reg.19.304 and 40 C.F.R. § 63.7540(a)(17)]

A. The permittee shall determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or the permittee’s own fuel analysis, according to the provisions in the site-specific fuel analysis plan developed according to §63.7521(b). [Reg.19.304 and 40 C.F.R. § 63.7540(a)(17)(i)]

B. The permittee shall determine the new mixture of fuels that will have the highest content of TSM. [Reg.19.304 and 40 C.F.R. § 63.7540(a)(17)(ii)]

C. The permittee shall recalculate the TSM emission rate from the boiler or process heater under these new conditions using Equation 14 of §63.7530. The recalculated TSM emission rate must be less than the applicable emission limit. [Reg.19.304 and 40 C.F.R. § 63.7540(a)(17)(iii)]

x. If the permittee demonstrates compliance with an applicable TSM emission limit through performance testing, and the permittee plans to burn a new type of fuel or a new mixture of fuels, the permittee shall recalculate the maximum TSM input using Equation 9 of §63.7530. If the results of recalculating the maximum TSM input using Equation 9 of §63.7530 are higher than the maximum total selected input level established during the previous performance test, then the permittee shall conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. The permittee shall also establish new operating limits based on this performance test according to the procedures in §63.7530(b). The
permittee is not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). The permittee may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculting the TSM emission rate. [Reg.19.304 and 40 C.F.R. § 63.7540(a)(16)]

k. The permittee shall conduct all applicable performance tests according to §63.7520 on an annual basis. Annual performance tests must be completed no more than 13 months after the previous performance test. The permittee may choose to conduct performance testing on a less frequent schedule provided the permittee demonstrates all of the following:

i. The performance test show for a given pollutant for at least 2 consecutive years show that the emissions are at or below 75 percent of the emission limit,

ii. There are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, and

iii. Subsequent performance tests are conducted no more than 37 months after the previous performance test

[Reg.19.304 and 40 C.F.R. § 63.7515(a) and (b)]

l. If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Table 2 to Subpart DDDDD) for a pollutant, the permittee shall conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit). [Reg.19.304 and 40 C.F.R. § 63.7515 (c)]

m. The permittee shall report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to §63.7530 and Table 7 to Subpart DDDDD, as applicable. The reports for all subsequent performance tests must include all applicable information required in §63.7550. [Reg.19.304 and 40 C.F.R. § 63.7515 (f)]

n. The permittee shall conduct a 5-year performance tune-up according to §63.7540(a)(12). Each 5-year performance tune-up must be conducted no more than 61 months after the previous tune-up. [Reg.19.304 and 40 C.F.R. § 63.7515 (f)]
o. The permittee shall submit to the Administrator all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply by the dates specified. [Reg.19.304 and 40 C.F.R. § 63.7545 (a)]

p. As specified in §63.9(b)(2), if startup an affected source commences before January 31, 2013, the permittee shall submit an Initial Notification not later than 120 days after January 31, 2013. [Reg.19.304 and 40 C.F.R. § 63.7545 (a)]

q. If the permittee is required to conduct a performance test the permittee shall submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin. [Reg.19.304 and 40 C.F.R. § 63.7545 (d)]

r. The permittee shall submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in §63.7545 (e)(1) through (8), as applicable. [Reg.19.304 and 40 C.F.R. § 63.7545 (e)]

i. A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under 40 C.F.R. §241.3, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of §241.3, and justification for the selection of fuel(s) burned during the compliance demonstration. [Reg.19.304 and 40 C.F.R. § 63.7545 (e)(1)]

ii. Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including: [Reg.19.304 and 40 C.F.R. § 63.7545 (e)(2)]

   A. Identification of whether the permittee is complying with the PM emission limit or the alternative TSM emission limit. [Reg.19.304 and 40 C.F.R. § 63.7545 (e)(2)(i)]

   B. (ii) Identification of whether the permittee is complying with the output-based emission limits or the heat input-based (i.e.,
iii. A summary of the maximum CO emission levels recorded during the performance test to show that the permittee has met any applicable emission standard in Table 2 to Subpart DDDDD, if you are not using a CO CEMS to demonstrate compliance. [Reg.19.304 and 40 C.F.R. § 63.7545 (e)(3)]

iv. Identification of whether the permittee plans to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis. [Reg.19.304 and 40 C.F.R. § 63.7545 (e)(4)]

v. A signed certification that the permittee has met all applicable emission limits and work practice standards. [Reg.19.304 and 40 C.F.R. § 63.7545 (e)(6)]

vi. If the permittee had a deviation from any emission limit, work practice standard, or operating limit, the permittee shall also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report. [Reg.19.304 and 40 C.F.R. § 63.7545 (e)(7)]

vii. In addition to the information required in §63.9(h)(2), the notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official: [Reg.19.304 and 40 C.F.R. § 63.7545 (e)(8)]

   A. “This facility complies with the required initial tune-up according to the procedures in §63.7540(a)(10)(i) through (vi).” [Reg.19.304 and 40 C.F.R. § 63.7545 (e)(8)(i)]

   B. “This facility has had an energy assessment performed according to §63.7530(e).” [Reg.19.304 and 40 C.F.R. § 63.7545 (e)(4)(ii)]

   C. “No secondary materials that are solid waste were combusted in any affected unit.” [Reg.19.304 and 40 C.F.R. § 63.7545 (e)(8)(iii)]

s. If the permittee intends to commence or recommence combustion of solid waste, the permittee shall provide 30 days prior notice of the date upon which permittee will commence or recommence combustion of solid waste. The notification must identify: [Reg.19.304 and 40 C.F.R. § 63.7545 (g)]

i. The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) or process heater(s) that
will commence burning solid waste, and the date of the notice.  
[Reg.19.304 and 40 C.F.R. § 63.7545 (g)(1)]

ii. The currently applicable subcategories under this subpart.  [Reg.19.304 and 40 C.F.R. § 63.7545 (g)(2)]

iii. The date on which you became subject to the currently applicable emission limits.  [Reg.19.304 and 40 C.F.R. § 63.7545 (g)(3)]

iv. The date upon which you will commence combusting solid waste.  [Reg.19.304 and 40 C.F.R. § 63.7545 (g)(4)]

t. If the permittee has switched fuels or made a physical change to the boiler and the fuel switch or physical change resulted in the applicability of a different subcategory, the permittee shall provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:  [Reg.19.304 and 40 C.F.R. § 63.7545 (h)]

i. The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.  [Reg.19.304 and 40 C.F.R. § 63.7545 (h)(1)]

ii. The currently applicable subcategory under this subpart.  [Reg.19.304 and 40 C.F.R. § 63.7545 (h)(2)]

iii. The date upon which the fuel switch or physical change occurred.  [Reg.19.304 and 40 C.F.R. § 63.7545 (h)(3)]

u. The permittee shall submit each report in Table 9 to Subpart DDDDD that applies.  [Reg.19.304 and 40 C.F.R. § 63.7550 (a)]

<table>
<thead>
<tr>
<th>NESHAP Subpart DDDDD Table 9 Applicable Reporting Requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>You must submit a(n)</strong></td>
</tr>
<tr>
<td>1. Compliance report</td>
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</table>
### NESHAP Subpart DDDDD Table 9 Applicable Reporting Requirements

<table>
<thead>
<tr>
<th>You must submit</th>
<th>The report must contain . . .</th>
<th>You must submit the report . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>a(n) period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and</td>
<td></td>
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<tr>
<td>c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard during the reporting period, the report must contain the information in §63.7550(d); and</td>
<td></td>
<td></td>
</tr>
<tr>
<td>d. If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), or otherwise not operating, the report must contain the information in §63.7550(e)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

v. Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), the permittee shall submit each report, according to §63.7550(h), by the date in Table 9 to Subpart DDDDD and according to the requirements in §63.7550 (b)(1) through (5). [Reg.19.304 and 40 C.F.R. § 63.7550 (b)]

**Note:** The above condition by referencing § 63.7550 (h) requires the compliance reports to be submitted electronically (with some exceptions) through EPA’s Central Date Exchange (CDX) and Compliance and Emissions Data Reporting Interface (CEDRI) using the file format generated through the EPA’s Electronic Reporting Tool (ERT). The monitoring, recordkeeping, and reporting requirements in Section VIII of this permit continue to apply.

i. The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on July 31 or January 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for the permittee’s source in §63.7495. [Reg.19.304 and 40 C.F.R. § 63.7550 (b)(1)]

ii. The first compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of
the first calendar half after the compliance date that is specified for each boiler or process heater in §63.7495.  [Reg.19.304 and 40 C.F.R. § 63.7550 (b)(2)]

iii. Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.  [Reg.19.304 and 40 C.F.R. § 63.7550 (b)(3)]

iv. Each subsequent compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.  [Reg.19.304 and 40 C.F.R. § 63.7550 (b)(4)]

v. For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to § 70.6(a)(3)(iii)(A) or § 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in 40 C.F.R. § 63.7550 (b)(1) through (4).  [Reg.19.304 and 40 C.F.R. § 63.7550 (b)(5)]

w. In addition to the information required by Table 9 to Subpart DDDDD, the compliance reports must contain the information in § 63.7550 (c)(5)(i) though (xvii), as applicable. The applicable information includes, but is not necessarily limited to, the following:  [Reg.19.304 and 40 C.F.R. § 63.7550 (c)]

i. The permittee shall include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.  [Reg.19.304 and 40 C.F.R. § 63.7550 (c)(5)(v)]

ii. The permittee shall include the total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.  [Reg.19.304 and 40 C.F.R. § 63.7550 (c)(5)(vi)]

iii. If the permittee is conducting performance tests once every 3 years consistent with §63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.  [Reg.19.304 and 40 C.F.R. § 63.7550 (c)(5)(vii)]
iv. A statement indicating that the permittee burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if the permittee did burn a new type of fuel and is subject to an emission limit for a given pollutant (HCl, Mercury, or TSM), the permittee shall provide information that demonstrates the source is still within its maximum pollutant input level established during the previous performance test. If the permittee wishes to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and cannot demonstrate compliance with the maximum pollutant input operating limit, the permittee shall include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel. [Reg.19.304 and 40 C.F.R. § 63.7550 (c)(5)(viii) and (ix)]

v. If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by the permittee during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with §63.7500(a)(3), including actions taken to correct the malfunction. [Reg.19.304 and 40 C.F.R. § 63.7550 (c)(5)(xiii)]

vi. The compliance report must include a statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. [Reg.19.304 and 40 C.F.R. § 63.7550 (c)(5)(xvii)]

x. For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where the permittee is not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in § 63.7550 (d)(1) through (3). [Reg.19.304 and 40 C.F.R. § 63.7550 (d)]

i. A description of the deviation and which emission limit or operating limit from which you deviated. [Reg.19.304 and 40 C.F.R. § 63.7550 (d)(1)]

ii. Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken. [Reg.19.304 and 40 C.F.R. § 63.7550 (d)(2)]

iii. If the deviation occurred during an annual performance test, provide the date the annual performance test was completed. [Reg.19.304 and 40 C.F.R. § 63.7550 (d)(3)]
y. For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where the permittee is using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in 63.7550(e)(1) through (9) of this section. This includes any deviations from the site-specific monitoring plan as required in §63.7505(d). [Reg.19.304 and 40 C.F.R. § 63.7550(e)]

i. The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from). [Reg.19.304 and 40 C.F.R. § 63.7550(e)(1)]

ii. The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks. [Reg.19.304 and 40 C.F.R. § 63.7550(e)(2)]

iii. The date, time, and duration that each CMS was out of control, including the information in §63.8(c)(8). [Reg.19.304 and 40 C.F.R. § 63.7550(e)(3)]

iv. The date and time that each deviation started and stopped. [Reg.19.304 and 40 C.F.R. § 63.7550(e)(4)]

v. A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period. [Reg.19.304 and 40 C.F.R. § 63.7550(e)(5)]

vi. A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes. [Reg.19.304 and 40 C.F.R. § 63.7550(e)(6)]

vii. A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period. [Reg.19.304 and 40 C.F.R. § 63.7550(e)(7)]

viii. A brief description of the source for which there was a deviation. [Reg.19.304 and 40 C.F.R. § 63.7550(e)(8)]

ix. A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation. [Reg.19.304 and 40 C.F.R. § 63.7550(e)(9)]

z. The permittee shall submit the reports according to the procedures specified in §63.7550(h)(1) through (3). [Reg.19.304 and 40 C.F.R. § 63.7550(h)]
Within 60 days after the date of completing each performance test (defined in §63.2) as required by this subpart the permittee shall submit the results of the performance tests, including any associated fuel analyses, required by this subpart and the compliance reports required in §63.7550(b) to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of the 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 the 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 the EPA via CDX as described earlier in this paragraph. At the discretion of the Administrator, you must also submit these reports, including the confidential business information, to the Administrator in the format specified by the Administrator. 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. [Reg.19.304 and 40 C.F.R. § 63.7550 (h)(1)]

The permittee submit all reports required by Table 9 of this subpart electronically using CEDRI that is accessed through the 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 report the permittee shall submit the report to the Administrator at the appropriate address listed in §63.13. At the discretion of the Administrator, the permittee shall also submit these reports, to the Administrator in the format specified by the Administrator. [Reg.19.304 and 40 C.F.R. § 63.7550 (h)(3)]

The permittee shall keep records according to § 63.7555 (a)(1) and (2). [Reg.19.304 and 40 C.F.R. § 63.7555 (a)]

A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv). [Reg.19.304 and 40 C.F.R. § 63.7555 (a)(1)]
ii. Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(viii). [Reg.19.304 and 40 C.F.R. § 63.7555 (a)(2)]

bb. For each CEMS, COMS, and continuous monitoring system the permittee shall keep records according to § 63.7555 (b)(1) through (5). [Reg.19.304 and 40 C.F.R. § 63.7555 (b)]

i. Records described in §63.10(b)(2)(vii) through (x). [Reg.19.304 and 40 C.F.R. § 63.7555 (b)(1)]

ii. Monitoring data for continuous opacity monitoring system during a performance evaluation as required in §63.6(h)(7)(i) and (ii). [Reg.19.304 and 40 C.F.R. § 63.7555 (b)(2)]

iii. Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3). [Reg.19.304 and 40 C.F.R. § 63.7555 (b)(3)]

iv. Records of the date and time that each deviation started and stopped. [Reg.19.304 and 40 C.F.R. § 63.7555 (b)(5)]

cc. The permittee shall keep the records required in Table 8 to Subpart DDDDD including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that apply. [Reg.19.304 and 40 C.F.R. § 63.7555 (c)]

dd. For each boiler or process heater subject to an emission limit in Table 2 to Subpart, the permittee shall also keep the applicable records in § 63.7555 (d)(1) through (11). These requirements include, but are not necessarily limited to, the following: [Reg.19.304 and 40 C.F.R. § 63.7555 (d)]

i. The permittee shall keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used. [Reg.19.304 and 40 C.F.R. § 63.7555 (d)(1)]

ii. If the permittee combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 C.F.R. §241.3(b)(1) and (2), the permittee shall keep a record that documents how the secondary material meets each of the legitimacy criteria under §241.3(d)(1). If the permittee combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to §241.3(b)(4), the permittee shall keep records as to how the operations that produced the fuel satisfy the definition of processing in §241.2. If the fuel received a non-waste determination pursuant to the petition process
submitted under §241.3(c) the permittee shall 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, the permittee shall keep records documenting that the material is listed as a non-waste under §241.4(a). Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in § 63.7555 (d)(2). [Reg.19.304 and 40 C.F.R. § 63.7555 (d)(2)]

iii. A copy of all calculations and supporting documentation of maximum pollutant (HCl, Mercury, or TSM) fuel input that were done to demonstrate continuous compliance with the pollutant emission limit, for sources that demonstrate compliance through performance testing. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum pollutant fuel input or pollutant emission rates. [Reg.19.304 and 40 C.F.R. § 63.7555 (d)(4), (5), and (9)]

iv. If, consistent with §63.7515(b), the permittee may choose to stack test less frequently than annually, the permittee shall keep a record that documents that the emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year. [Reg.19.304 and 40 C.F.R. § 63.7555 (d)(6)]

v. The permittee shall maintain records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment. [Reg.19.304 and 40 C.F.R. § 63.7555 (d)(7)]

vi. The permittee shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in §63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation. [Reg.19.304 and 40 C.F.R. § 63.7555 (d)(8)]

vii. The permittee shall maintain records of the calendar date, time, occurrence and duration of each startup and shutdown. [Reg.19.304 and 40 C.F.R. § 63.7555 (d)(10)]

viii. The permittee shall maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown. [Reg.19.304 and 40 C.F.R. § 63.7555 (d)(11)]
**SN-14**

**Wood-fired Boiler #2**

**Description**

Source SN-14 is a wood waste fired boiler with a heat input capacity of 60 MMBTU/hr. Because of the date of installation and the heat input capacity, this boiler is subject to the provisions of 40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. Particulate emissions are controlled by a multiclone and an electrostatic precipitator.

**Specific Conditions**

24. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition is based on the maximum heat input capacity of the equipment for the hourly rate for SO$_2$ and VOC and testing for PM$_{10}$, CO, and NO$_X$ through compliance with Plantwide Condition #9. Compliance with the annual rate shall be demonstrated through compliance with Specific Condition #27. [Reg.19.501 et seq. and 40 C.F.R. § 52 Subpart E]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
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<tbody>
<tr>
<td>PM$_{10}$</td>
<td>2.2</td>
<td>7.5</td>
</tr>
<tr>
<td>SO$_2$</td>
<td>1.6</td>
<td>5.5</td>
</tr>
<tr>
<td>VOC</td>
<td>4.4</td>
<td>15.4</td>
</tr>
<tr>
<td>CO</td>
<td>29.9</td>
<td>104.5</td>
</tr>
<tr>
<td>NO$_X$</td>
<td>18.9</td>
<td>66.0</td>
</tr>
<tr>
<td>Lead</td>
<td>5.69E-05</td>
<td>1.99E-04</td>
</tr>
</tbody>
</table>

25. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition is based on the maximum heat input capacity of the equipment for the hourly. Compliance with the annual rate shall be demonstrated through compliance with Specific Condition #27. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>2.9</td>
<td>10.1</td>
</tr>
<tr>
<td>HCl</td>
<td>0.49</td>
<td>1.71</td>
</tr>
<tr>
<td>Single HAP</td>
<td>0.49</td>
<td>1.71</td>
</tr>
<tr>
<td>Total HAPs</td>
<td>N/A</td>
<td>2.30</td>
</tr>
</tbody>
</table>

26. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition is based compliance with Specific Condition #31. [Reg.19.901 et seq. and 40 C.F.R. § 52 Subpart E]
### Pollutant BACT Emission Limits

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>BACT Emission Limits</th>
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</thead>
<tbody>
<tr>
<td>VOC</td>
<td>0.07 lb/MMBtu</td>
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<tr>
<td></td>
<td>25 ppmvd @ 15% O₂</td>
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<tr>
<td></td>
<td>4.2 lb/hr</td>
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<td></td>
<td>18.4 tpy</td>
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</tbody>
</table>

27. The permittee shall not produce more than 1.2 MM lbs of steam per day and 350.4 MM lbs of steam in any 12-month period at SN-14. Compliance with the annual rate shall be demonstrated through compliance with Specific Condition #28. Compliance with the daily rate shall be demonstrated through compliance with Specific Condition #32.g. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

28. The facility shall maintain monthly records that demonstrate compliance with the limits set in Specific Condition #27 which may be used by the Department for enforcement purposes. These records shall be updated by the fifteenth day of the month following the month to which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. An annual total and each individual month’s steam production data shall be submitted to the Department in accordance with General Provision #7. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

29. The permittee shall only combust wood waste and small amounts of oil soaked absorbent material used to clean up incidental, onsite oil spills. Absorbent material shall consist only of sawdust, wood chips, or commercially sold products made specifically for absorbing oil spills. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

30. The permittee shall operate the opacity monitor at SN-14 in compliance with the Department’s CEMS standards in Appendix C of this permit. Compliance or non-compliance with these standards does not necessarily constitute compliance or non-compliance with the NSPS CEMS standards. [Reg.19.703, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

#### Testing Requirements
(For Compliance with BACT Determination)

31. The permittee shall perform stack testing for VOC in accordance with Plantwide Condition #3 and EPA Reference Method 25A as found in 40 CFR Part 60, Appendix A to demonstrate compliance with the limits specified in Specific Condition #26. The testing shall be performed while SN-14 is operating at or above 90% maximum rated capacity. Testing shall be conducted every five years after the initial test in accordance with Plantwide Condition #3. [Reg.19.702 and 40 C.F.R. § 52 Subpart E]
NSPS Requirements

32. SN-14 is subject to and shall comply with applicable provisions of 40 CFR Part 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. Applicable provisions of Subpart Dc include, but are not limited to, the following: [Reg. 19.304 and 40 C.F.R. § 60.40c]

a. The permittee shall not discharge to the atmosphere any gases from SN-14 that contain particulate matter in excess of 0.10 lb/ MMBTU. [Reg. 19.304 and 40 C.F.R. § 60.43c (b)(1)]

b. The permittee shall not exceed 20% opacity from source SN-14 as measured by EPA Reference Method 9 except for one 6-minute period per hour of not more than 27%. [Reg. 19.304 and 40 C.F.R. § 60.43c (c)]

c. The particulate matter and opacity standards apply at all times, except during periods of startup, shutdown, or malfunctions. [Reg. 19.304 and 40 C.F.R. § 60.43c (d)]

d. The permittee shall install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The records shall be maintained onsite for at least two years and made available to Department personnel upon request. [Reg. 19.304 and 40 C.F.R. §§ 60.47c (a) and 60.48c (i)]

e. The COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 (Appendix B to Part 60 – Performance Specifications). Compliance or non-compliance with the specifications set forth in Appendix B of 40 CFR Part 60 does not necessarily constitute compliance or non-compliance with the Department’s CEMS standards. [Reg. 19.304 and 40 C.F.R. § 60.47c (b)]

f. The permittee shall record any exceedances in opacity and submit excess emission reports for any excess emissions. The records shall be kept on site for at least two years. A report shall be submitted to the Department in accordance with General Provision #7.

Quarterly COMS excess emissions reports submitted pursuant to the ADEQ's CEMS standards in Appendix C of the permit shall satisfy the requirements of this condition as long as the ADEQ quarterly report contains the same information as required by the NSPS. [Reg. 19.304 and 40 C.F.R. §§ 60.48c (c) and 60.48c (j)]

g. The permittee shall maintain daily records of the wood residue combusted in SN-14. These records shall be kept on site for at least two years and made available
to Department personnel upon request. [Reg. 19.304 and 40 C.F.R. §§ 60.48c (g) and 60.48c (i)]

CAM Requirements

33. SN-14 is subject to Compliance Assurance Monitoring and shall comply with all applicable provisions, including but not limited to: [Reg. 19.703, 40 C.F.R. § 52, Subpart E, and 40 C.F.R. § 64.6]

a. The permittee shall maintain a COMS at a location such that its readings are representative of the stack exhaust opacity. [Reg. 19.703, 40 C.F.R. § 52, Subpart E, and 40 C.F.R. § 64.6(c)(1)]

b. The permittee shall maintain the indicator range on the COMS to make readings of opacities between 0% and 100%. [Reg. 19.703, 40 C.F.R. § 52, Subpart E, and 40 C.F.R. § 64.6(c)(1)]

c. The permittee shall maintain a data acquisition system that completes a minimum of one cycle of opacity sampling and analyzing for each successive 10 second period. The data shall be used to determine six-minute average opacity readings from the COM. An alarm (visible and/or audible) shall be triggered when a six minute reading is over 20%. If more than one six minute reading exceeds the opacity limit in a one hour period the permittee shall take immediate corrective action. Records of any one hour period requiring corrective action shall be kept onsite, updated daily, and made available to Department personnel upon request. [Reg. 19.703, 40 C.F.R. § 52, Subpart E, and 40 C.F.R. § 64.6(c)(1)]

d. The “rake-out” period shall be noted on the operator’s log and shall not be used to monitor compliance or to determine compliance with CAM requirements. [Reg. 19.703, 40 C.F.R. § 52 Subpart E, and 40 C.F.R. § 64.6(c)(3)]

e. The rake-out period is to be scheduled for the same specific time each day and shall be recorded. The Department shall be notified in advance and in writing of the schedule or any changes. The process of soot blowing, grate cleaning, ash raking, and refiring or any part thereof is considered one activity, and the time limit on this activity is 45 minutes. This activity shall not be performed more than once in any consecutive 8 hour period, and it shall not be performed more than three times in any consecutive 24 hour period. [Reg. 18.501(A)(4)]
SN-14 is an affected source subject to the requirements of 40 C.F.R. 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. For the purpose of the subpart the boiler is designated as an existing boiler that belongs to the stoker/sloped grate/other units designed to burn wet biomass/bio-based solid subcategory. The permittee shall comply with the subpart no later than January 31, 2016, except as provided in §63.6(i). The permittee shall demonstrate compliance with Specific Condition #23 and all applicable Subpart DDDDD requirements for SN-14. [Reg.19.304 and 40 C.F.R. § 63, Subpart DDDDD]
0SN-18 and SN-19

Fuel Tanks

Description

Source SN-18 is a horizontal fixed roof tank with a 10,000 gallon capacity which is used to store gasoline. Source SN-19 is a horizontal fixed roof tank with a 10,000 gallon capacity which is used to store diesel fuel.

Specific Conditions

35. The permit allows the following maximum emission rates. Compliance with this condition shall be demonstrated through compliance with Specific Conditions #37 and #39. [Reg.19.501 et seq. and 40 C.F.R. § 52 Subpart E]

<table>
<thead>
<tr>
<th>Source No.</th>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>18</td>
<td>VOC</td>
<td>6.1</td>
<td>4.5</td>
</tr>
<tr>
<td>19</td>
<td>VOC</td>
<td>0.3</td>
<td>0.1</td>
</tr>
</tbody>
</table>

36. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition shall be demonstrated through compliance with Specific Conditions #37 and #39. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

<table>
<thead>
<tr>
<th>Source No.</th>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>18</td>
<td>Single HAP</td>
<td>0.91</td>
<td>0.67</td>
</tr>
<tr>
<td></td>
<td>Total HAPs</td>
<td>N/A</td>
<td>1.95</td>
</tr>
</tbody>
</table>

37. The permittee shall not receive more than 10,000 gallons in a 24-hour period of RVP 15 gasoline (or lower vapor pressure fuels) and shall not exceed an annual throughput of 100,000 gallon of gasoline at SN-18 in any 12-month period. Gasoline (RVP 15 or lower vapor pressure fuels) shall be the only fuel stored in SN-18. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

38. The facility shall maintain records that demonstrate compliance with the limits set in Specific Condition #37 which may be used by the Department for enforcement purposes. These records shall be updated by the fifteenth day of the month following the month to which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. An annual total and each individual month’s gasoline throughput data shall be submitted to the Department in accordance with General Provision #7. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

39. The permittee shall not exceed an annual throughput of 160,000 gallon of diesel from SN 19 in any 12-month period. Diesel shall be the only fuel stored in SN-19. [Reg.19.705,
Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

40. The facility shall maintain records that demonstrate compliance with the limits set in Specific Condition #39 which may be used by the Department for enforcement purposes. These records shall be updated by the fifteenth day of the month following the month to which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. An annual total and each individual month’s diesel throughput data shall be submitted to the Department in accordance with General Provision #7. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]
SN-20

Wood-Fired Boiler #3

Description

Source SN-20 is a wood waste fired boiler with a heat input capacity of 60 MMBTU/hr. Because of the date of proposed installation and the heat input capacity, this boiler is subject to the provisions of 40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. Particulate emissions are controlled by a multiclone and an electrostatic precipitator.

Specific Conditions

41. The permit allows the following maximum emission rates. Compliance with this condition is based on the maximum heat input capacity of the equipment for the hourly rate and compliance with Specific Condition #45 for the annual rate. [Reg. 19.901 et seq., and 40 C.F.R. § 52, Subpart E]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM/PM₁₀</td>
<td>5.1</td>
<td>17.6</td>
</tr>
<tr>
<td>VOC</td>
<td>4.4</td>
<td>15.4</td>
</tr>
<tr>
<td>CO</td>
<td>29.9</td>
<td>104.5</td>
</tr>
<tr>
<td>NOₓ</td>
<td>18.9</td>
<td>66.0</td>
</tr>
</tbody>
</table>

42. The permit allows the following maximum emission rates. Compliance with this condition is based on the maximum heat input capacity of the equipment for the hourly rate and compliance with Specific Condition #45 for the annual rate. [Reg.19.501 et seq. and 40 C.F.R. § 52 Subpart E]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM₁₀</td>
<td>3.8</td>
<td>13.1</td>
</tr>
<tr>
<td>SO₂</td>
<td>1.6</td>
<td>5.5</td>
</tr>
<tr>
<td>Lead</td>
<td>5.69E-05</td>
<td>1.99E-04</td>
</tr>
</tbody>
</table>

43. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition is based on the maximum heat input capacity of the equipment for the hourly rate and compliance with Specific Condition #45 for the annual rate. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
44. The permittee shall comply with the following BACT determinations for SN-20. Initial compliance with the emission limits set forth in the following table shall be demonstrated by the initial performance test at SN-20. The initial compliance test performed on March 22, 2006. [Reg.19.901 et seq. and 40 C.F.R. § 52 Subpart E]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Limit</th>
<th>Compliance</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM10</td>
<td>0.08 lb/MMBTU</td>
<td>Stack Testing</td>
</tr>
<tr>
<td>VOC</td>
<td>0.07 lb/MMBTU</td>
<td>Stack Testing</td>
</tr>
<tr>
<td>CO</td>
<td>0.475 lb/MMBTU</td>
<td>Stack Testing</td>
</tr>
<tr>
<td>NOX</td>
<td>0.30 lb/MMBTU</td>
<td>Stack Testing</td>
</tr>
</tbody>
</table>

45. The permittee shall not produce more than 1.2 MM lbs of steam per day and 350.4 MM lbs of steam in any 12-month period at SN-20. Compliance with the annual rate shall be demonstrated through compliance with Specific Condition #46. Compliance with the daily rate shall be demonstrated through compliance with Specific Condition #53.g. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

46. The facility shall maintain monthly records that demonstrate compliance with the limits set in Specific Condition #45 which may be used by the Department for enforcement purposes. These records shall be updated by the fifteenth day of the month following the month to which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. An annual total and each individual month’s steam production data shall be submitted to the Department in accordance with General Provision #7. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

47. The permittee shall only combust wood waste and small amounts of oil soaked absorbent material used to clean up incidental, onsite oil spills. Absorbent material shall consist only of sawdust, wood chips, or commercially sold products made specifically for absorbing oil spills. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

48. The permittee shall operate the opacity monitor at SN-20 in compliance with the Department’s CEMS standards in Appendix C of this permit. Compliance or non-compliance with these standards does not necessarily constitute compliance or non-compliance with the NSPS COM requirements. [Reg.19.703, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
Testing Requirements
(For Compliance with BACT Determination)

49. The permittee shall perform stack testing for PM$_{10}$ in accordance with Plantwide Condition #3 and EPA Reference Method 201A and Method 202 or a Method 5 and Method 202 to demonstrate compliance with the limits specified in Specific Conditions #41 and #44. By using Methods 5 and 202 for PM$_{10}$ the facility will assume all collected particulate is PM$_{10}$. The testing shall be performed while SN-20 is operating at or above 90% maximum rated capacity. Testing shall be conducted every five years after the initial test in accordance with Plantwide Condition #3. The initial test was conducted on March 22, 2006; the subsequent test was conducted on March 11, 2011; therefore, the next testing must be conducted by March 2016. [Reg.19.702 and 40 C.F.R. § 52 Subpart E]

50. The permittee shall perform stack testing for VOC in accordance with Plantwide Condition #3 and EPA Reference Method 25A as found in 40 CFR Part 60, Appendix A to demonstrate compliance with the limits specified in Specific Conditions #41 and #44. The testing shall be performed while SN-20 is operating at or above 90% maximum rated capacity. Testing shall be conducted every five years after the initial test in accordance with Plantwide Condition #3. The initial test was conducted on March 22, 2006; the subsequent test was conducted on March 11, 2011; therefore, the next testing must be conducted by March 2016. [Reg.19.702 and 40 C.F.R. § 52 Subpart E]

51. The permittee shall perform stack testing for NO$_{X}$ in accordance with Plantwide Condition #3 and EPA Reference Method 7E as found in 40 CFR Part 60, Appendix A to demonstrate compliance with the limits specified in Specific Conditions #41 and #44. The testing shall be performed while SN-20 is operating at or above 90% maximum rated capacity. Testing shall be conducted every five years after the initial test in accordance with Plantwide Condition #3. The initial test was conducted on March 22, 2006; the subsequent test was conducted on March 11, 2011; therefore, the next testing must be conducted by March 2016. [Reg.19.702 and 40 C.F.R. § 52 Subpart E]

52. The permittee shall perform stack testing for CO in accordance with Plantwide Condition #3 and EPA Reference Method 10 as found in 40 CFR Part 60, Appendix A to demonstrate compliance with the limits specified in Specific Conditions #41 and #44. The testing shall be performed while SN-20 is operating at or above 90% maximum rated capacity. Testing shall be conducted every five years after the initial test in accordance with Plantwide Condition #3. The initial test was conducted on March 22, 2006; the subsequent test was conducted on March 11, 2011; therefore, the next testing must be conducted by March 2016. Testing performed to satisfy the Boiler MACT requirement may also be used to satisfy the provisions of this condition. [Reg.19.702 and 40 C.F.R. § 52 Subpart E]
NSPS Requirements

53. SN-20 is subject to and shall comply with applicable provisions of 40 CFR Part 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (Appendix C). Applicable provisions of Subpart Dc include, but are not limited to, the following: [Reg. 19.304 and 40 C.F.R. § 60.40c]

a. The permittee shall not discharge to the atmosphere any gases from SN-20 that contain particulate matter in excess of 0.10 lb/ MMBTU. [Reg. 19.304 and 40 C.F.R. § 60.43c (b)(1)]

b. The permittee shall not exceed 20% opacity from source SN-20 as measured by EPA Reference Method 9 except for one 6-minute period per hour of not more than 27%. [Reg. 19.304 and 40 C.F.R. § 60.43c (c)]

c. The particulate matter and opacity standards apply at all times, except during periods of startup, shutdown, or malfunctions. [Reg. 19.304 and 40 C.F.R. § 60.43c (d)]

d. The permittee shall install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The records shall be maintained onsite for at least two years and made available to Department personnel upon request. [Reg. 19.304 and 40 C.F.R. §§ 60.47c (a) and 60.48c (i)]

e. The COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 (Appendix B to Part 60 – Performance Specifications). Compliance or non-compliance with the specifications set forth in Appendix B of 40 CFR Part 60 does not necessarily constitute compliance or non-compliance with the Department’s CEMS standards. [Reg. 19.304 and 40 C.F.R. § 60.47c (b)]

f. The permittee shall record any exceedances in opacity and submit excess emission reports for any excess emissions. The records shall be kept on site for at least two years. A report shall be submitted to the Department in accordance with General Provision #7.

Quarterly COMS excess emissions reports submitted pursuant to the ADEQ’s CEMS standards in Appendix C of the permit shall satisfy the requirements of this condition as long as the ADEQ quarterly report contains the same information as required by the NSPS. [Reg. 19.304 and 40 C.F.R. §§ 60.48c (c) and 60.48c (j)]

g. The permittee shall maintain daily records of the wood residue combusted in SN-20. These records shall be kept on site for at least two years and made available
to Department personnel upon request. [Reg. 19.304 and 40 C.F.R. §§ 60.48c (g) and 60.48c (i)]

CAM Requirements

54. SN-20 is subject to Compliance Assurance Monitoring and shall comply with all applicable provisions, including but not limited to: [Reg. 19.703, 40 C.F.R. § 52 Subpart E, and 40 C.F.R. § 64.6]
   
a. The permittee shall maintain a COMS at a location such that its readings are representative of the stack exhaust opacity. [Reg. 19.703, 40 C.F.R. § 52 Subpart E, and 40 C.F.R. § 64.6(c)(1)]

b. The permittee shall maintain the indicator range on the COMS to make readings of opacities between 0% and 100%. [Reg. 19.703, 40 C.F.R. § 52 Subpart E, and 40 C.F.R. § 64.6(c)(1)]

c. The permittee shall maintain a data acquisition system that completes a minimum of one cycle of opacity sampling and analyzing for each successive 10 second period. The data shall be used to determine six-minute average opacity readings from the COM. An alarm (visible and/or audible) shall be triggered when a six minute reading is over 10%. If an alarm is triggered, the permittee shall take immediate corrective action. Records of any corrective action shall be kept onsite, updated daily, and made available to Department personnel upon request. [Reg. 19.703, 40 C.F.R. § 52 Subpart E, and 40 C.F.R. § 64.6(c)(1)]

d. The “rake-out” period shall be noted on the operator’s log and shall not be used to monitor compliance or to determine compliance with CAM requirements. [Reg. 19.703, 40 C.F.R. § 52 Subpart E, and 40 C.F.R. § 64.6(c)(3)]

e. The rake-out period is to be scheduled for the same specific time each day and shall be recorded. The Department shall be notified in advance and in writing of the schedule or any changes. The process of soot blowing, grate cleaning, ash raking, and refiring or any part thereof is considered one activity, and the time limit on this activity is 45 minutes. This activity shall not be performed more than once in any consecutive 8 hour period, and it shall not be performed more than three times in any consecutive 24 hour period. [Reg. 18.501(A)(4)]

NESHAP Subpart DDDDD Requirements for SN-20

55. SN-20 is an affected source subject to the requirements of 40 C.F.R. 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. For the purpose of the subpart the boiler is designated as an existing boiler that belongs to the hybrid suspension/grate burners designed to burn wet biomass/bio-based solid subcategory. The permittee shall comply with the subpart no later than January 31, 2016,
except as provided in §63.6(i). Applicable requirements include, but are not necessarily limited to, the following: [Reg.19.304 and 40 C.F.R. § 63, Subpart DDDDD]

a. The permittee shall not allow emissions to exceed the following emission limits, except during periods of startup and shutdown. The permittee shall demonstrate compliance with these limits through performance testing except where the subpart provides for fuel analysis to be used in lieu of performance testing. [Reg.19.304 and 40 C.F.R. § 63.7500(a)(1)]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Limits (lb per MMBtu of heat input)</th>
<th>Alternative Output-based Limits (lb per MMBtu of steam output)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HCl</td>
<td>2.2E-02</td>
<td>2.5E-02</td>
</tr>
<tr>
<td>Mercury</td>
<td>5.7E-06</td>
<td>6.4E-06</td>
</tr>
<tr>
<td>CO</td>
<td>3,500 ppmvd @ 3% O&lt;sub&gt;2&lt;/sub&gt;</td>
<td>3.5</td>
</tr>
<tr>
<td>Filterable PM</td>
<td>4.4E-01</td>
<td>5.5E-01</td>
</tr>
</tbody>
</table>

b. As an alternative to complying with limit for Filterable PM in the preceding condition, the permittee shall not allow the total selected metals emissions to exceed the following emission limits, except during periods of startup and shutdown. The permittee shall demonstrate compliance with these limits through performance testing except where the subpart provides for fuel analysis to be used in lieu of performance testing.

*Total selected metals (TSM)* means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

[Reg.19.304 and 40 C.F.R. § 63.7500(a)(1)]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Limits (lb per MMBtu of heat input)</th>
<th>Alternative Output-based Limits (lb per MMBtu of steam output)</th>
</tr>
</thead>
<tbody>
<tr>
<td>TSM</td>
<td>4.5E-04</td>
<td>5.7E-04</td>
</tr>
</tbody>
</table>

c. For SN-20 the permittee shall demonstrate compliance with all applicable requirements of Subpart DDDDD and the conditions in Specific Conditions #23 (c) through (dd). [Reg.19.304 and 40 C.F.R. § 63, Subpart DDDDD]

d. The permittee shall meet the definition of hybrid suspension grate boiler as defined in 40 C.F.R. § 63.7575. The biomass fuel combusted in this unit must exceed a moisture content of 40 percent on an as-fired annual heat input basis as demonstrated by monthly fuel analysis. [Reg.19.304 and 40 C.F.R. § 63.7575]
SN-24

Boiler Ash, Bark, and Sawdust Storage Piles

Description

Various operations throughout the mill cause PM emissions, such as the loading and the storage of boiler ash dumpsters, and chip storage piles.

Boiler Ash

Ash from the wood fired boilers fall onto a drag chain conveyor, which are located under each ash source (i.e., the multi-clone hoppers, the ESP discharge, and the grate discharge). The drag chain conveyors are sealed units with water maintained at a level that covers the discharge points for the ash. The drag chains are level for a distance and then turn up an incline to discharge the wet ash into a hopper(s). The wet ash is then disposed offsite.

Bark and Sawdust Storage Piles

The powerhouse includes three boilers (SN-13, SN-14, and SN-20) with heat input capacities of 60 MMBtu/hr each. Each boiler is closed-coupled to a biomass gasifier that consumes the bark and green sawdust to produce bio-gas. Bark and green sawdust are conveyed to either the wood-fired boiler fuel storage silo or to storage piles.

Specific Conditions

56. The permit allows the following maximum emission rates. Compliance with this condition is demonstrated through compliance with Plantwide Condition #7. [Reg.19.501 et seq. and 40 C.F.R. § 52 Subpart E]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM$_{10}$</td>
<td>0.4</td>
<td>1.3</td>
</tr>
<tr>
<td>VOC</td>
<td>0.2</td>
<td>0.7</td>
</tr>
</tbody>
</table>

57. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition is demonstrated through compliance with Plantwide Condition #7. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>0.4</td>
<td>1.3</td>
</tr>
</tbody>
</table>

58. The permittee will not conduct operations in such a manner as to unnecessarily cause air contaminants and other pollutants to become airborne. [Reg. 18.901 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
SN-25

Planer Mill Shavings Conveying and Storage

Description

Two cyclones are associated with the Planer Mill, SN-16 and SN-22. Both cyclones work in conjunction to collect planer mill shavings. Approximately 250 tons of shaving are generated for every million board feet processed. PM emissions occur as a result of conveying and storing the planermill shavings.

Specific Conditions

59. The permit allows the following maximum emission rates. Compliance with this condition shall be demonstrated through compliance with Plantwide Condition #7. [Reg.19.501 et seq. and 40 C.F.R. § 52 Subpart E]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM₁₀</td>
<td>0.1</td>
<td>0.1</td>
</tr>
</tbody>
</table>

60. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition shall be demonstrated through compliance with Plantwide Condition #7. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>0.1</td>
<td>0.1</td>
</tr>
</tbody>
</table>

61. The permittee will not conduct operations in such a manner as to unnecessarily cause air contaminants and other pollutants to become airborne. [Reg. 18.901 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
SN-27 and SN-29

Paved and Unpaved Haul Roads

Description

Various types of trucks and company vehicles travel throughout the plant on both paved (SN-27) and unpaved (SN-29) roads. Dust emissions are generated as a result of this traffic.

Specific Conditions

62. The permit allows the following maximum emission rates. Compliance with this condition shall be demonstrated through compliance with Specific Condition #65. [Reg.19.501 et seq. and 40 C.F.R. § 52 Subpart E]

<table>
<thead>
<tr>
<th>Source No.</th>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>27</td>
<td>PM$_{10}$</td>
<td>0.6</td>
<td>1.7</td>
</tr>
<tr>
<td>29</td>
<td>PM$_{10}$</td>
<td>0.5</td>
<td>1.4</td>
</tr>
</tbody>
</table>

63. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition shall be demonstrated through compliance with Specific Condition #65. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

<table>
<thead>
<tr>
<th>Source No.</th>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>27</td>
<td>PM</td>
<td>2.8</td>
<td>8.4</td>
</tr>
<tr>
<td>29</td>
<td>PM</td>
<td>1.6</td>
<td>4.8</td>
</tr>
</tbody>
</table>

64. The silt loading for the paved roads shall not exceed 0.6 g/m$^2$. The permittee shall perform a one-time test within 180 days of the issuance of this permit (Permit No. 697-AOP-R9) to determine the silt loading of the paved roads at SN-27. The permittee shall use ASTM-C-136 and Appendix C.1 and C.2 of AP-42 for this test. The test was conducted on May 8, 2009. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

65. The permittee shall not exceed 90,834 vehicle miles traveled per consecutive twelve (12) month period for the paved roads (SN-27) at the facility. The permittee shall not exceed 1,310 vehicle miles traveled per consecutive twelve (12) month period for the unpaved roads (SN-29) at the facility. Compliance with this condition shall be demonstrated through compliance with Plantwide Condition #7. Any increase in the Plantwide Condition #7 shall require the permittee to recalculate emission limits and VMT limits. [Reg.19.501 et seq. and 40 C.F.R. § 52 Subpart E]

66. The permittee shall develop and implement a Road Maintenance Plan (RMP) which is designed to maintain the particulate emissions from the roads at or below the limits listed in Specific Conditions #62 and #63. The RMP shall identify all measures taken by the
permittee to ensure initial and continuous compliance. The results from the testing required by Specific Condition #64 shall be submitted within 30 days of the testing and shall be included in the RMP. A copy of the RMP shall be submitted within 90 days of the testing, and the RMP shall be kept onsite and be made available upon request by Department personnel. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

Note: The permittee has stated that the road maintenance plan was submitted to ADEQ on July 29, 2009.

67. Any measure taken by the permittee which involves periodic application such as wet suppression or application of a surfactant, vacuuming, and/or sweeping shall be repeated when visible emissions from the roads can be observed but no less frequent than once a month. The permittee shall maintain a log of such applications, and the log shall be kept onsite and made available to Department personnel upon request. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

68. The permittee shall not use any surfactant which contains VOC or HAP. The permittee shall include the MSDS for any surfactant applied to the roads at the facility in the RMP. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]

69. Nothing in this permit shall be construed to authorize a violation of the Arkansas Water and Air Pollution Control Act or the federal National Pollutant Discharge Elimination System (NPDES). [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]
SN-28

Feed Water Pump

Description

The diesel fired feed water pump is used to supply water to the mill’s three boilers in the event of an emergency. The engine is tested up to 10 minutes on a weekly basis.

Specific Conditions

70. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition is based on the maximum capacity of the equipment for hourly rate and 500 hours of operation for annual rate. [Reg.19.501 et seq. and 40 C.F.R. § 52 Subpart E]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM$_{10}$</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>SO$_2$</td>
<td>0.2</td>
<td>0.1</td>
</tr>
<tr>
<td>VOC</td>
<td>0.2</td>
<td>0.1</td>
</tr>
<tr>
<td>CO</td>
<td>0.9</td>
<td>0.2</td>
</tr>
<tr>
<td>NO$_X$</td>
<td>1.1</td>
<td>0.3</td>
</tr>
</tbody>
</table>

71. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition is based on the maximum capacity of the equipment for hourly rate and 500 hours of operation for annual rate. [Reg.18.801 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>lb/hr</th>
<th>tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>0.1</td>
<td>0.1</td>
</tr>
</tbody>
</table>

72. The permittee will maintain monthly records, which demonstrate compliance with the annual hours of operation. The permittee will update the records by the fifteenth day of the month following the month to which the records pertain. The permittee will keep the records onsite, and make the records available to Department personnel upon request. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

73. The permittee shall comply with the applicable requirements of 40 CFR 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. Pursuant to §63.6590 (c), compliance is demonstrated through compliance with the applicable requirements of 40 CFR Part 60, Subpart III – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The applicable requirements of Subpart III include but are not limited to the following: [Reg. 19.304 and 40 C.F.R. § 63, Subpart ZZZZ and 40 C.F.R. § 60, Subpart III]
a. There is no time limit on the use of emergency stationary ICE in emergency situations. Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. Anyone may petition the EPA for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under §60.4205 but not §60.4204, any operation other than emergency operation, and maintenance and testing as permitted in §60.4211, is prohibited. [Reg. 19.304 and 40 C.F.R. § 60.4211 (e)]

b. The permittee shall not discharge to the atmosphere any gases from SN-28 that contain the following pollutants in excess of the specified limits. Pursuant to §60.4211 (c), compliance with this condition shall be demonstrated by purchasing an engine certified to the emission standards below and installed and configured according to the manufacturer’s specifications. The permittee will keep the certification onsite, and make the certification available to Department personnel upon request. [Reg. 19.304 and 40 C.F.R. § 60.4205 (b)]

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Emission Limit g/kW-hr</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM</td>
<td>0.40</td>
</tr>
<tr>
<td>NMHC + NOX *</td>
<td>7.5</td>
</tr>
<tr>
<td>CO</td>
<td>5.0</td>
</tr>
</tbody>
</table>

* NMHC means non-methane hydrocarbon, and for the purpose of this permit NMHC is VOC.

c. The permittee shall not discharge to the atmosphere any gases from SN-28 that exceed the opacity limits listed below. Pursuant to §60.4211 (c), compliance with this condition shall be demonstrated by purchasing an engine certified to the emission standards below and installed and configured according to the manufacturer’s specifications. The permittee will keep the certification onsite, and make the certification available to Department personnel upon request. [Reg. 19.304 and 40 C.F.R. § 60.4205 (b)]

<table>
<thead>
<tr>
<th>Engine Mode</th>
<th>Opacity Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Acceleration</td>
<td>20%</td>
</tr>
<tr>
<td>Lugging</td>
<td>15%</td>
</tr>
<tr>
<td>Peak Acceleration or Lugging</td>
<td>50%</td>
</tr>
</tbody>
</table>
d. The permittee, beginning October 1, 2007, shall only combust diesel fuel with a maximum sulfur content of 0.05% by weight and either a minimum centane index of 40 or a maximum aromatic content of 35% by volume. [Reg. 19.304 and 40 C.F.R. § 60.4207(a)]

e. The permittee, beginning October 1, 2010, shall only combust diesel fuel with a maximum sulfur content of 0.0015% by weight and either a minimum centane index of 40 or a maximum aromatic content of 35% by volume. [Reg. 19.304 and 40 C.F.R. § 60.4207(b)]

f. The permittee shall install a non-resettable hour meter prior to startup of SN-28. [Reg. 19.304 and 40 C.F.R. § 60.4209(a)]

g. The permittee shall operate and maintain the stationary IC internal combustion engine and control device according to the manufacturer’s written instructions or procedures developed by the permittee that are approved by the engine manufacturer. In addition, permittee may only change those settings that are permitted by the manufacturer. [Reg. 19.304 and 40 C.F.R. § 60.4211 (a)]

h. The permittee shall record the time of operation of SN-28 and the reason the source was in operation during that time. [Reg. 19.304 and 40 C.F.R. § 60.4214(b)]
SECTION V: COMPLIANCE PLAN AND SCHEDULE

PotlatchDeltic Manufacturing L.L.C. - Waldo Mill will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future regulations that may apply and determine their applicability with any necessary action taken on a timely basis.
SECTION VI: PLANTWIDE CONDITIONS

1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Reg.19.704, 40 C.F.R. § 52 Subpart E, and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [Reg.19.410(B) and 40 C.F.R. § 52 Subpart E]

3. The permittee must test any equipment scheduled for testing, unless otherwise stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) new equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) operating equipment according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) business days in advance of such test. The permittee shall submit the compliance test results to the Department within sixty (60) calendar days after completing the testing. [Reg.19.702 and/or Reg.18.1002 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

4. The permittee must provide:
   a. Sampling ports adequate for applicable test methods;
   b. Safe sampling platforms;
   c. Safe access to sampling platforms; and
   d. Utilities for sampling and testing equipment.

   [Reg.19.702 and/or Reg.18.1002 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee shall maintain the equipment in good condition at all times. [Reg.19.303 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

6. This permit subsumes and incorporates all previously issued air permits for this facility. [Reg. 26 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

7. The permittee shall not exceed combined kiln production of more than 300 million board feet in any 12-month period. [Reg.19.705, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 70.6]
8. The permittee shall maintain records of the amount of board feet processed in order to demonstrate compliance with Plantwide Condition #7 and which may be used by the Department for enforcement purposes. These records shall be updated no later than the fifteenth day of the month following the month which the records represent, shall be kept on site, and shall be made available to Department personnel upon request. An annual total and each month’s individual data shall be submitted to the Department in accordance with General Provision #7. [Reg.19.705 and 40 C.F.R. § 52 Subpart E]

9. The permittee shall test SN-13 and SN-14 according to test methods and provisions listed in the table below. The test for CO and NOX shall be conducted simultaneously. All tests shall be conducted in accordance with Plantwide Condition #3, except that the testing schedule described below shall be followed. Test results shall be maintained on-site, made available to Department personnel upon request, and shall be submitted to the Department in accordance with General Provision #7.

The permittee is required to test only one boiler at a time in order to meet the requirements of this condition. In order to allow both boilers to be tested, the permittee shall test the untested boiler during the next testing period. If the permittee passes a given test for two consecutive tests, then the permittee is required to repeat the test only once every five years. [Reg.19.702 and 40 C.F.R. § 52 Subpart E]

<table>
<thead>
<tr>
<th>SN</th>
<th>Pollutant</th>
<th>Test Method</th>
<th>Test Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>13</td>
<td>PM</td>
<td>5 or 201A</td>
<td>Every 2 Years</td>
</tr>
<tr>
<td></td>
<td>CO</td>
<td>10</td>
<td>Every 2 Years</td>
</tr>
<tr>
<td></td>
<td>NOX</td>
<td>7E</td>
<td>Every 2 years</td>
</tr>
<tr>
<td>14</td>
<td>PM</td>
<td>5 or 201A</td>
<td>Every 2 years</td>
</tr>
<tr>
<td></td>
<td>CO</td>
<td>10</td>
<td>Every 2 years</td>
</tr>
<tr>
<td></td>
<td>NOX</td>
<td>7E</td>
<td>Every 2 years</td>
</tr>
</tbody>
</table>

10. A reasonable possibility exists that the modification resulting in issuance of Permit No. 697-AOP-R13 may result in a significant increase for PM, PM10, PM2.5. The applicable requirements of “reasonable possibility” include, but are not limited to, the following:

a. Before beginning actual construction of the project, the permittee shall document and maintain a record of the following information: [40 C.F.R. § 52.21 (r)(6)(i)]

i. A description of the project;

ii. Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

iii. A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of
emissions excluded under paragraph (b)(41)(ii)(c) of 40 CFR §52.21 and an explanation for why such amount was excluded, and any netting calculations, if applicable.

b. The permittee shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in Plantwide Condition #10 (a)(ii); and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity or potential to emit that regulated NSR pollutant at such emissions unit. [40 C.F.R. § 52.21 (r)(6)(iii)]

c. The permittee shall submit a report if the annual emissions, in tons per year, from the project identified in Plantwide Condition #10 (a)(i), exceed the baseline actual emissions (as documented and maintained pursuant Plantwide Condition #10 (a)(iii)), by a significant amount (i.e. 25 tons PM, 15 tons PM$_{10}$, or 10 tons PM$_{2.5}$), and if such emissions differ from the preconstruction projection as documented and maintained pursuant to Plantwide Condition #10 (a)(iii). Such report shall be submitted within 60 days after the end of such year. The report shall contain the following: [40 C.F.R. § 52.21 (r)(6)(v)]

i. The name, address and telephone number of the major stationary source;

ii. The annual emissions as calculated pursuant Plantwide Condition #10 (b); and

iii. Any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

d. The permittee shall make the information required to be documented and maintained pursuant to Plantwide Condition #10 available for review upon a request for inspection by ADEQ, the EPA, or the general public. [40 C.F.R. §52.21 (r)(7) and 40 C.F.R. §70.4(b)(3)(viii)]

Title VI Provisions

11. The permittee must comply with the standards for labeling of products using ozone-depleting substances. [40 C.F.R. § 82 Subpart E]

   a. All containers containing a class I or class II substance stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced to interstate commerce pursuant to § 82.106.
b. The placement of the required warning statement must comply with the requirements pursuant to § 82.108.
c. The form of the label bearing the required warning must comply with the requirements pursuant to § 82.110.
d. No person may modify, remove, or interfere with the required warning statement except as described in § 82.112.

12. The permittee must comply with the standards for recycling and emissions reduction, except as provided for MVACs in Subpart B. [40 C.F.R. § 82 Subpart F]

a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156.
b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158.
c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161.
d. Persons disposing of small appliances, MVACs, and MVAC like appliances must comply with record keeping requirements pursuant to § 82.166. (“MVAC like appliance” as defined at § 82.152)
e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.156.
f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

13. If the permittee manufactures, transforms, destroys, imports, or exports a class I or class II substance, the permittee is subject to all requirements as specified in 40 C.F.R. § 82 Subpart A, Production and Consumption Controls.

14. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 C.F.R. § 82 Subpart B, Servicing of Motor Vehicle Air Conditioners.

The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term “MVAC” as used in Subpart B does not include the air tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC 22 refrigerant.

15. The permittee can switch from any ozone depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 C.F.R. § 82 Subpart G.
PotlatchDeltic Manufacturing L.L.C. - Waldo Mill
Permit #: 0697-AOP-R18
AFIN: 14-00037
SECTION VII: INSIGNIFICANT ACTIVITIES

The Department deems the following types of activities or emissions as insignificant on the basis of size, emission rate, production rate, or activity in accordance with Group A of the Insignificant Activities list found in Regulation 18 and Regulation 19 Appendix A. Group B insignificant activities may be listed but are not required to be listed in permits. Insignificant activity emission determinations rely upon the information submitted by the permittee in an application dated July 3, 2013. [Reg.26.304 and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

<table>
<thead>
<tr>
<th>Description</th>
<th>Category</th>
</tr>
</thead>
<tbody>
<tr>
<td>14 Bulk oil storage tanks, each tank 1000 gal or less</td>
<td>Group A, #3</td>
</tr>
<tr>
<td>Debarking Operations</td>
<td>Group A, #13</td>
</tr>
<tr>
<td>Sawdust Conveyors</td>
<td>Group A, #13</td>
</tr>
<tr>
<td>Bark/chip conveyors and drop points</td>
<td>Group A, #13</td>
</tr>
<tr>
<td>Wood Hog</td>
<td>Group A, #13</td>
</tr>
<tr>
<td>Batten Manufacturing Process</td>
<td>Group A, #13</td>
</tr>
</tbody>
</table>
SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 et seq.) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 et seq.). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (Ark. Code Ann. § 8-4-101 et seq.) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 C.F.R. § 70.6(b)(2)]

2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 C.F.R. § 70.6(a)(2) and Reg.26.701(B)]

3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee’s right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Department takes final action on the renewal application. The Department will not necessarily notify the permittee when the permit renewal application is due. [Reg.26.406]

4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, et seq. (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 C.F.R. § 70.6(a)(1)(ii) and Reg.26.701(A)(2)]

5. The permittee must maintain the following records of monitoring information as required by this permit.

   a. The date, place as defined in this permit, and time of sampling or measurements;
   b. The date(s) analyses performed;
   c. The company or entity performing the analyses;
   d. The analytical techniques or methods used;
   e. The results of such analyses; and
   f. The operating conditions existing at the time of sampling or measurement.

   [40 C.F.R. § 70.6(a)(3)(ii)(A) and Reg.26.701(C)(2)]
6. The permittee must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 C.F.R. § 70.6(a)(3)(ii)(B) and Reg.26.701(C)(2)(b)]

7. The permittee must submit reports of all required monitoring every six (6) months. If the permit establishes no other reporting period, the reporting period shall end on the last day of the month six months after the issuance of the initial Title V permit and every six months thereafter. The report is due on the first day of the second month after the end of the reporting period. The first report due after issuance of the initial Title V permit shall contain six months of data and each report thereafter shall contain 12 months of data. The report shall contain data for all monitoring requirements in effect during the reporting period. If a monitoring requirement is not in effect for the entire reporting period, only those months of data in which the monitoring requirement was in effect are required to be reported. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Reg.26.2 must certify all required reports. The permittee will send the reports to the address below:

Arkansas Department of Environmental Quality
Office of Air Quality
ATTN: Compliance Inspector Supervisor
5301 Northshore Drive
North Little Rock, AR  72118-5317

[40 C.F.R. § 70.6(a)(3)(iii)(A) and Reg.26.701(C)(3)(a)]

8. The permittee shall report to the Department all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.

a. For all upset conditions (as defined in Reg.19.601), the permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:

i. The facility name and location;
ii. The process unit or emission source deviating from the permit limit;
iii. The permit limit, including the identification of pollutants, from which deviation occurs;
iv. The date and time the deviation started;
v. The duration of the deviation;
vi. The emissions during the deviation;
vii. The probable cause of such deviations;
viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future; and
ix. The name of the person submitting the report.
The permittee shall make a full report in writing to the Department within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit’s limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a.


9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 C.F.R. § 70.6(a)(5), Reg.26.701(E), and Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. § 7401, et seq. and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 C.F.R. § 70.6(a)(6)(i) and Reg.26.701(F)(1)]

11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 C.F.R. § 70.6(a)(6)(ii) and Reg.26.701(F)(2)]

12. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 C.F.R. § 70.6(a)(6)(iii) and Reg.26.701(F)(3)]

13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 C.F.R. § 70.6(a)(6)(iv) and Reg.26.701(F)(4)]

14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for
modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Department may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 C.F.R. § 70.6(a)(6)(v) and Reg.26.701(F)(5)]

15. The permittee must pay all permit fees in accordance with the procedures established in Regulation 9. [40 C.F.R. § 70.6(a)(7) and Reg.26.701(G)]

16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 C.F.R. § 70.6(a)(8) and Reg.26.701(H)]

17. If the permit allows different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 C.F.R. § 70.6(a)(9)(i) and Reg.26.701(I)(1)]

18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source’s potential to emit, unless the Department specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 C.F.R. § 70.6(b) and Reg.26.702(A) and (B)]

19. Any document (including reports) required by this permit pursuant to 40 C.F.R. § 70 must contain a certification by a responsible official as defined in Reg.26.2. [40 C.F.R. § 70.6(c)(1) and Reg.26.703(A)]

20. The permittee must allow an authorized representative of the Department, upon presentation of credentials, to perform the following: [40 C.F.R. § 70.6(c)(2) and Reg.26.703(B)]

   a. Enter upon the permittee’s premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
   b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;
   c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
   d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.

21. The permittee shall submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The
permittee must submit the compliance certification annually. If the permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due on the first day of the second month after the end of the reporting period. The permittee must also submit the compliance certification to the Administrator as well as to the Department. All compliance certifications required by this permit must include the following: [40 C.F.R. § 70.6(c)(5) and Reg.26.703(E)(3)]

a. The identification of each term or condition of the permit that is the basis of the certification;
b. The compliance status;
c. Whether compliance was continuous or intermittent;
d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit; and
e. Such other facts as the Department may require elsewhere in this permit or by § 114(a)(3) and § 504(b) of the Act.

22. Nothing in this permit will alter or affect the following: [Reg.26.704(C)]

a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
c. The applicable requirements of the acid rain program, consistent with § 408(a) of the Act; or
d. The ability of EPA to obtain information from a source pursuant to § 114 of the Act.

23. This permit authorizes only those pollutant emitting activities addressed in this permit. [Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311]

24. The permittee may request in writing and at least 15 days in advance of the deadline, an extension to any testing, compliance or other dates in this permit. No such extensions are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion in the following circumstances:

a. Such an extension does not violate a federal requirement;
b. The permittee demonstrates the need for the extension; and
c. The permittee documents that all reasonable measures have been taken to meet the current deadline and documents reasons it cannot be met.

25. The permittee may request in writing and at least 30 days in advance, temporary emissions and/or testing that would otherwise exceed an emission rate, throughput requirement, or other limit in this permit. No such activities are authorized until the permittee receives written Department approval. Any such emissions shall be included in the facility’s total emissions and reported as such. The Department may grant such a request, at its discretion under the following conditions:

a. Such a request does not violate a federal requirement;
b. Such a request is temporary in nature;
c. Such a request will not result in a condition of air pollution;
d. The request contains such information necessary for the Department to evaluate the request, including but not limited to, quantification of such emissions and the date/time such emission will occur;
e. Such a request will result in increased emissions less than five tons of any individual criteria pollutant, one ton of any single HAP and 2.5 tons of total HAPs; and
f. The permittee maintains records of the dates and results of such temporary emissions/testing.

[Reg.18.314(B), Reg.19.416(B), Reg.26.1013(B), Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]

26. The permittee may request in writing and at least 30 days in advance, an alternative to the specified monitoring in this permit. No such alternatives are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion under the following conditions:

a. The request does not violate a federal requirement;
b. The request provides an equivalent or greater degree of actual monitoring to the current requirements; and
c. Any such request, if approved, is incorporated in the next permit modification application by the permittee.


27. Any credible evidence based on sampling, monitoring, and reporting may be used to determine violations of applicable emission limitations. [Reg.18.1001, Reg.19.701, Ark. Code Ann. § 8-4-203 as referenced by Ark. Code Ann. §§ 8-4-304 and 8-4-311, and 40 C.F.R. § 52 Subpart E]
APPENDIX A

40 C.F.R. Part 60, Subpart Dc – Standards of Performance for Small Industrial/Commercial/Institutional Steam Generating Units
Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

SOURCE: 72 FR 32759, June 13, 2007, unless otherwise noted.

§60.40c Applicability and delegation of authority.

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


§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 hydrodesulfurization technology.

*Distillate oil* means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see §60.17), 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, sander dust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.


§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:

\[
E_s = \left( \frac{K_a H_a + K_b H_b + K_c H_c}{H_a + H_b + H_c} \right)
\]

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 $SO_2$ emission rate; and

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

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

(h) For affected facilities listed under paragraphs (h)(1), (2), (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 $SO_2$ emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

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


§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.


§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 affected 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 $E_{ao}$ ($E_{ao,o}$) 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 $E_{ao,o}$ is computed using the following formula:

$$ E_{ao,o} = \frac{E_{ao} - E_{w}(1 - X_{w})}{X_{w}} $$

Where:
\[ E_{\text{o,o}} = \text{Adjusted } E_{\text{o}}, \text{ ng/J (lb/MMBtu)}; \]

\[ E_{\text{o}} = \text{Hourly SO}_2 \text{ emission rate, ng/J (lb/MMBtu)}; \]

\[ E_{w} = \text{SO}_2 \text{ concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value } E_{w} \text{ for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure } E_{w} \text{ if the owner or operator elects to assume } E_{w} = 0. \]

\[ X_{k} = \text{Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.} \]

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

(f) Affected facilities subject to the percent reduction requirements under §60.42c(a) or (b) shall determine compliance with the SO\(_2\) emission limits under §60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO\(_2\) emission rate is computed using the following formula:

\[
\%P_{i} = 100 \left( 1 - \frac{\%R_{g}}{100} \right) \left( 1 - \frac{\%R_{f}}{100} \right)
\]

Where:

\%P\(_{i}\) = Potential SO\(_2\) emission rate, in percent;

\%R\(_{g}\) = SO\(_2\) removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

\%R\(_{f}\) = SO\(_2\) removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

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

(i) To compute the \( \%P_{i} \), an adjusted \( \%R_{g}(\%R_{o}) \) is computed from \( E_{w,o} \) from paragraph (e)(1) of this section and an adjusted average SO\(_2\) inlet rate \( E_{o,o} \) using the following formula:

\[
\%R_{g,o} = 100 \left( 1 - \frac{E_{o,o}}{E_{o,i}} \right)
\]

Where:

\%R\(_{o}\) = Adjusted \%R\(_{i}\) in percent;

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

\( E_{o,o} = \text{Adjusted average SO}_2 \text{ inlet rate, ng/J (lb/MMBtu)}. \)
(ii) To compute $E_{so}$, an adjusted hourly SO$_2$ inlet rate ($E_{hio}$) is used. The $E_{hio}$ is computed using the following formula:

$$E_{hio} = \frac{E_u - E_w (1 - X)}{X}$$

Where:

$E_{so}$ = Adjusted $E_u$, ng/J (lb/MMBtu);

$E_u$ = 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

$X$ = 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 $\%P$, and $E_{so}$ 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 $\%P$, or $E_{so}$ 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(c)(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).


§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 (c)(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).


§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.
APPENDIX B

40 C.F.R. Part 60, Subpart IIII – *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*
Subpart III—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

SOURCE: 71 FR 39172, July 11, 2006, unless otherwise noted.

WHAT THIS SUBPART COVERS

§60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of §60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.
(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

EMISSION STANDARDS FOR MANUFACTURERS

§60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:
(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 1 to 40 CFR 1042.1 identifies 40 CFR part 1042 as being applicable, 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Remote areas of Alaska; and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

(h) Stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with auxiliary emission control devices (AECDs) as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR 89.112 while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011; 81 FR 44219, July 7, 2016]

§60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and
(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI internal combustion engines identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 2 to 40 CFR 1042.101 identifies Tier 3 standards as being applicable, the requirements applicable to Tier 3 engines in 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Remote areas of Alaska; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011; 81 FR 44219, July 7, 2016]

§60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

EMISSION STANDARDS FOR OWNERS AND OPERATORS

§60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO$_x$ in the stationary CI internal combustion engine exhaust to the following:
(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hour (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where $n$ is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NOX in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where $n$ is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NOX in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0.20}$ g/HP-hr) where $n$ (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in §60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

(f) Owners and operators of stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with AECDs as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR 89.112 while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011; 81 FR 44219, July 7, 2016]

§60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

1. For engines installed prior to January 1, 2012, limit the emissions of NO\textsubscript{X} in the stationary CI internal combustion engine exhaust to the following:
   (i) \(17.0 \text{ g/KW-hr (12.7 g/HP-hr)}\) when maximum engine speed is less than 130 rpm;
   (ii) \(45 \cdot n^{-0.2} \text{ g/KW-hr (34 \cdot n^{-0.2} g/HP-hr)}\) when maximum engine speed is 130 or more but less than 2,000 rpm, where \(n\) is maximum engine speed; and
   (iii) \(9.8 \text{ g/kW-hr (7.3 g/HP-hr)}\) when maximum engine speed is 2,000 rpm or more.

2. For engines installed on or after January 1, 2012, limit the emissions of NO\textsubscript{X} in the stationary CI internal combustion engine exhaust to the following:
   (i) \(14.4 \text{ g/KW-hr (10.7 g/HP-hr)}\) when maximum engine speed is less than 130 rpm;
   (ii) \(44 \cdot n^{-0.23} \text{ g/KW-hr (33 \cdot n^{-0.23} g/HP-hr)}\) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where \(n\) is maximum engine speed; and
   (iii) \(7.7 \text{ g/KW-hr (5.7 g/HP-hr)}\) when maximum engine speed is greater than or equal to 2,000 rpm.

3. Limit the emissions of PM in the stationary CI internal combustion engine exhaust to \(0.40 \text{ g/KW-hr (0.30 g/HP-hr)}\).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in §60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]
§60.4206  How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 over the entire life of the engine.

[76 FR 37969, June 28, 2011]

FUEL REQUIREMENTS FOR OWNERS AND OPERATORS

§60.4207  What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder are no longer subject to the requirements of paragraph (a) of this section, and must use fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.


OTHER REQUIREMENTS FOR OWNERS AND OPERATORS

§60.4208  What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.
(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

COMPLIANCE REQUIREMENTS

§60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?
(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and (e) and §60.4202(e) and (f) using the certification procedures required in 40 CFR part 94, subpart C, or 40 CFR part 1042, subpart C, as applicable, and must test their engines as specified in 40 CFR part 94 or 1042, as applicable.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89, 40 CFR part 94 or 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.
(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR parts 89, 94, 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as “Fire Pump Applications Only”.

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §60.4201 or §60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.
(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

(j) Stationary CI ICE manufacturers may equip their stationary CI internal combustion engines certified to the emission standards in 40 CFR part 1039 with AECDs for qualified emergency situations according to the requirements of 40 CFR 1039.665. Manufacturers of stationary CI ICE equipped with AECDs as allowed by 40 CFR 1039.665 must meet all of the requirements in 40 CFR 1039.665 that apply to manufacturers. Manufacturers must document that the engine complies with the Tier 1 standard in 40 CFR 89.112 when the AECD is activated. Manufacturers must provide any relevant testing, engineering analysis, or other information in sufficient detail to support such statement when applying for certification (including amending an existing certificate) of an engine equipped with an AECD as allowed by 40 CFR 1039.665.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 81 FR 44219, July 7, 2016]

§60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an
owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in Table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer’s emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NOx and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NOx and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(e) or §60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in §60.4204(e) or §60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in §60.4212 or §60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be
considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.
(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

(h) The requirements for operators and prohibited acts specified in 40 CFR 1039.665 apply to owners or operators of stationary CI ICE equipped with AECDs for qualified emergency situations as allowed by 40 CFR 1039.665.


TESTING REQUIREMENTS FOR OWNERS AND OPERATORS

§60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?
Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

\[
\text{NTE} = \text{STD} \times \frac{\text{New Engine Power}}{\text{EPA Engine Power}}
\]

Where:

\( \text{STD} \) = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

\( \text{STD} \) = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?
Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in §60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

\[
\frac{C_i - F \cdot C_o}{C_i} \cdot 100\%
\]

Where:

- \( C_i \) = concentration of NO\(_x\) or PM at the control device inlet,
- \( C_o \) = concentration of NO\(_x\) or PM at the control device outlet, and
- \( R \) = percent reduction of NO\(_x\) or PM emissions.

(2) You must normalize the NO\(_x\) or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O\(_2\)) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO\(_2\)) using the procedures described in paragraph (d)(3) of this section.

\[
\frac{C_{adj} \cdot 100}{C_d \cdot 20.9 - 5.9 \cdot %O_2}
\]

Where:

- \( C_{adj} \) = Calculated NO\(_x\) or PM concentration adjusted to 15 percent O\(_2\).
- \( C_d \) = Measured concentration of NO\(_x\) or PM, uncorrected.
- 5.9 = 20.9 percent O\(_2\)−15 percent O\(_2\), the defined O\(_2\) correction value, percent.
- \%O\(_2\) = Measured O\(_2\) concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O\(_2\) and CO\(_2\) concentration is measured in lieu of O\(_2\) concentration measurement, a CO\(_2\) correction factor is needed. Calculate the CO\(_2\) correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific \( F_c \) value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:
Where:

\[ F_0 = \text{Fuel factor based on the ratio of O}_2\text{ volume to the ultimate CO}_2\text{ volume produced by the fuel at zero percent excess air.} \]

\[ 0.209 = \text{Fraction of air that is O}_2\text{, percent/100.} \]

\[ F_d = \text{Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm}^3/\text{J (dscf}/10^6\text{ Btu).} \]

\[ F_c = \text{Ratio of the volume of CO}_2\text{ produced to the gross calorific value of the fuel from Method 19, dsm}^3/\text{J (dscf}/10^6\text{ Btu).} \]

(ii) Calculate the CO\textsubscript{2} correction factor for correcting measurement data to 15 percent O\textsubscript{2}, as follows:

\[ X_{\text{CO}_2} = \frac{5.9}{F_o} \quad (\text{Eq. 5}) \]

Where:

\[ X_{\text{CO}_2} = \text{CO}_2\text{ correction factor, percent.} \]

\[ 5.9 = 20.9\text{ percent } O_2 - 15\text{ percent } O_2, \text{ the defined } O_2\text{ correction value, percent.} \]

(iii) Calculate the NO\textsubscript{x} and PM gas concentrations adjusted to 15 percent O\textsubscript{2} using \text{CO}_2 as follows:

\[ C_{\text{adj}} = C_d \frac{X_{\text{CO}_2}}{\%\text{CO}_2} \quad (\text{Eq. 6}) \]

Where:

\[ C_{\text{adj}} = \text{Calculated NO}_x\text{ or PM concentration adjusted to 15 percent } O_2. \]

\[ C_d = \text{Measured concentration of NO}_x\text{ or PM, uncorrected.} \]

\[ \%\text{CO}_2 = \text{Measured CO}_2\text{ concentration, dry basis, percent.} \]

(e) To determine compliance with the NO\textsubscript{x} mass per unit output emission limitation, convert the concentration of NO\textsubscript{x} in the engine exhaust using Equation 7 of this section:

\[ \text{ER} = C_d \cdot \frac{1.912 \times 10^3}{1} \cdot \frac{Q}{1} \cdot \frac{T}{1} \cdot \frac{1}{10^3} \text{ kg-m/1000 s.} \]

Where:

\[ \text{ER} = \text{Emission rate in grams per KW-hour.} \]

\[ C_d = \text{Measured NO}_x\text{ concentration in ppm.} \]

\[ 1.912 \times 10^3 = \text{Conversion constant for ppm NO}_x\text{ to grams per standard cubic meter at 25 degrees Celsius.} \]

\[ Q = \text{Stack gas volumetric flow rate, in standard cubic meter per hour.} \]

\[ T = \text{Time of test run, in hours.} \]

\[ \text{KW-hour} = \text{Brake work of the engine, in KW-hour.} \]
(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

\[
ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}}
\]  
(Eq 8)

Where:

\( ER \) = Emission rate in grams per KW-hour.

\( C_{adj} \) = Calculated PM concentration in grams per standard cubic meter.

\( Q \) = Stack gas volumetric flow rate, in standard cubic meter per hour.

\( T \) = Time of test run, in hours.

\( \text{KW-hour} \) = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

**NOTIFICATION, REPORTS, AND RECORDS FOR OWNERS AND OPERATORS**

§60.4214  What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.
(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in §60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

1. The report must contain the following information:

   (i) Company name and address where the engine is located.

   (ii) Date of the report and beginning and ending dates of the reporting period.

   (iii) Engine site rating and model year.

   (iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

   (v) Hours operated for the purposes specified in §60.4211(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(2)(ii) and (iii).

   (vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §60.4211(f)(2)(ii) and (iii).

   (vii) Hours spent for operation for the purposes specified in §60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

2. The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

3. The annual report must be submitted electronically using the subpart specific reporting form in 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 report must be submitted to the Administrator at the appropriate address listed in §60.4.

(c) Owners or operators of stationary CI ICE equipped with AECDs pursuant to the requirements of 40 CFR 1039.665 must report the use of AECDs as required by 40 CFR 1039.665(e).


**SPECIAL REQUIREMENTS**

**§60.4215** What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in §60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NOx in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) \(45 \cdot n^{-0.2} \) g/KW-hr \((34 \cdot n^{-0.2} \) g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where \(n\) is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NOx in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) \(44 \cdot n^{-0.23} \) g/KW-hr \((33 \cdot n^{-0.23} \) g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where \(n\) is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

**§60.4216** What requirements must I meet for engines used in Alaska?
(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in remote areas of Alaska may meet the requirements of this subpart by manufacturing and installing engines meeting the requirements of 40 CFR parts 94 or 1042, as appropriate, rather than the otherwise applicable requirements of 40 CFR parts 89 and 1039, as indicated in §§60.4201(f) and 60.4202(g).

(c) Manufacturers, owners and operators of stationary CI ICE that are located in remote areas of Alaska may choose to meet the applicable emission standards for emergency engines in §§60.4202 and 60.4205, and not those for non-emergency engines in §§60.4201 and 60.4204, except that for 2014 model year and later non-emergency CI ICE, the owner or operator of any such engine that was not certified as meeting Tier 4 PM standards, must meet the applicable requirements for PM in §§60.4201 and 60.4204 or install a PM emission control device that achieves PM emission reductions of 85 percent, or 60 percent for engines with a displacement of greater than or equal to 30 liters per cylinder, compared to engine-out emissions.

(d) The provisions of §60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in remote areas of Alaska.

(e) The provisions of §60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and §60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in remote areas of Alaska from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011, as amended at 81 FR 44219, July 7, 2016]

§60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4204 or §60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

GENERAL PROVISIONS

§60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.
DEFINITIONS

§60.4219 What definitions apply to this subpart?

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

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.
Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in §60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in §60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §60.4211(f)(2)(ii) or (iii) and §60.4211(f)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means the calendar year in which an engine is manufactured (see “date of manufacture”), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see “date of manufacture”), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see “date of manufacture”).

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.
Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Remote areas of Alaska means areas of Alaska that meet either paragraph (1) or (2) of this definition.

(1) Areas of Alaska that are not accessible by the Federal Aid Highway System (FAHS).

(2) Areas of Alaska that meet all of the following criteria:

(i) The only connection to the FAHS is through the Alaska Marine Highway System, or the stationary CI ICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary CI ICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the source is less than 12 megawatts, or the stationary CI ICE is used exclusively for backup power for renewable energy.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart III.

Table 1 to Subpart III of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]
Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

<table>
<thead>
<tr>
<th>Engine power</th>
<th>NOₓ + NMHC</th>
<th>CO</th>
<th>PM</th>
</tr>
</thead>
<tbody>
<tr>
<td>KW&lt;8 (HP&lt;11)</td>
<td>7.5 (5.6)</td>
<td>8.0 (6.0)</td>
<td>0.40 (0.30)</td>
</tr>
<tr>
<td>8≤KW&lt;19 (11≤HP&lt;25)</td>
<td>7.5 (5.6)</td>
<td>6.6 (4.9)</td>
<td>0.40 (0.30)</td>
</tr>
<tr>
<td>19≤KW&lt;37 (25≤HP&lt;50)</td>
<td>7.5 (5.6)</td>
<td>5.5 (4.1)</td>
<td>0.30 (0.22)</td>
</tr>
</tbody>
</table>

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines
As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

<table>
<thead>
<tr>
<th>Engine power</th>
<th>Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>KW&lt;75 (HP&lt;100)</td>
<td>2011</td>
</tr>
<tr>
<td>75≤KW&lt;130 (100≤HP&lt;175)</td>
<td>2010</td>
</tr>
<tr>
<td>130≤KW≤560 (175≤HP≤750)</td>
<td>2009</td>
</tr>
<tr>
<td>KW&gt;560 (HP&gt;750)</td>
<td>2008</td>
</tr>
</tbody>
</table>

¹Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 kW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

<table>
<thead>
<tr>
<th>Maximum engine power</th>
<th>Model year(s)</th>
<th>NMHC + NOₓ</th>
<th>CO</th>
<th>PM</th>
</tr>
</thead>
<tbody>
<tr>
<td>KW&lt;8 (HP&lt;11)</td>
<td>2010 and earlier</td>
<td>10.5 (7.8)</td>
<td>8.0 (6.0)</td>
<td>1.0 (0.75)</td>
</tr>
<tr>
<td></td>
<td>2011 +</td>
<td>7.5 (5.6)</td>
<td>0.40 (0.30)</td>
<td></td>
</tr>
<tr>
<td>8≤KW&lt;19 (11≤HP&lt;25)</td>
<td>2010 and earlier</td>
<td>9.5 (7.1)</td>
<td>6.6 (4.9)</td>
<td>0.80 (0.60)</td>
</tr>
<tr>
<td></td>
<td>2011 +</td>
<td>7.5 (5.6)</td>
<td>0.40 (0.30)</td>
<td></td>
</tr>
<tr>
<td>19≤KW&lt;37 (25≤HP&lt;50)</td>
<td>2010 and earlier</td>
<td>9.5 (7.1)</td>
<td>5.5 (4.1)</td>
<td>0.80 (0.60)</td>
</tr>
<tr>
<td></td>
<td>2011 +</td>
<td>7.5 (5.6)</td>
<td>0.30 (0.22)</td>
<td></td>
</tr>
<tr>
<td>37≤KW&lt;56 (50≤HP&lt;75)</td>
<td>2010 and earlier</td>
<td>10.5 (7.8)</td>
<td>5.0 (3.7)</td>
<td>0.80 (0.60)</td>
</tr>
<tr>
<td></td>
<td>2011 +¹</td>
<td>4.7 (3.5)</td>
<td>0.40 (0.30)</td>
<td></td>
</tr>
<tr>
<td>56≤KW&lt;75 (75≤HP&lt;100)</td>
<td>2010 and earlier</td>
<td>10.5 (7.8)</td>
<td>5.0 (3.7)</td>
<td>0.80 (0.60)</td>
</tr>
<tr>
<td></td>
<td>2011 +¹</td>
<td>4.7 (3.5)</td>
<td>0.40 (0.30)</td>
<td></td>
</tr>
</tbody>
</table>
### Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

<table>
<thead>
<tr>
<th>Engine power</th>
<th>Starting model year</th>
</tr>
</thead>
<tbody>
<tr>
<td>$19 \leq \text{KW} &lt; 56$ (25 $\leq \text{HP} &lt; 75$)</td>
<td>2013</td>
</tr>
<tr>
<td>$56 \leq \text{KW} &lt; 130$ (75 $\leq \text{HP} &lt; 175$)</td>
<td>2012</td>
</tr>
<tr>
<td>$\text{KW} \geq 130$ (HP $\geq 175$)</td>
<td>2011</td>
</tr>
</tbody>
</table>

### Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

<table>
<thead>
<tr>
<th>Mode No.</th>
<th>Engine speed$^1$</th>
<th>Torque</th>
<th>Weighting</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

$^1$For model years 2011-2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

$^2$For model years 2010-2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

$^3$In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.
<table>
<thead>
<tr>
<th></th>
<th>Complying with the requirement to...</th>
<th>You must...</th>
<th>According to the following requirements...</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Stationary CI internal combustion engine with a displacement of ≥ 30 liters per cylinder</td>
<td>a. Reduce NOx emissions by 90 percent or more; i. Select the sampling port location and number/location of traverse points at the inlet and outlet of the control device;</td>
<td>(a) For NOx, O2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts &gt;6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (‘3-point long line’). If the duct is &gt;12 inches in diameter and the sampling port location meets the two and half-diameter criterion of Section 11.1.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.</td>
</tr>
<tr>
<td>2</td>
<td></td>
<td>ii. Measure O2 at the inlet and outlet of the control device;</td>
<td>(b) Measurements to determine O2 concentration must be made at the same time as the measurements for NOx concentration.</td>
</tr>
<tr>
<td>3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>---</td>
<td>---</td>
<td>---</td>
<td></td>
</tr>
<tr>
<td>iii. If necessary, measure moisture content at the inlet and outlet of the control device; and</td>
<td>(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)</td>
<td>(c) Measurements to determine moisture content must be made at the same time as the measurements for NOx concentration.</td>
<td></td>
</tr>
<tr>
<td>iv. Measure NOx at the inlet and outlet of the control device.</td>
<td>(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)</td>
<td>(d) NOx concentration must be at 15 percent O2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</td>
<td></td>
</tr>
<tr>
<td>b. Limit the concentration of NOx in the stationary CI internal combustion engine exhaust.</td>
<td>i. Select the sampling port location and number/location of traverse points at the exhaust of the stationary internal combustion engine; (a) For NOx, O2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts &gt;6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is &gt;12 inches in diameter and the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.</td>
<td>(b) Measurements to determine O2 concentration must be made at the same time as the measurement for NOx concentration.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>ii. Determine the O2 concentration of the stationary internal combustion engine exhaust at the sampling port location;</td>
<td>(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>(b) Measurements to determine O2 concentration must be made at the same time as the measurement for NOx concentration.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>iii. If necessary,</td>
<td>(2) Method 4 of 40 CFR part 60, appendix A-3</td>
<td>(c) Measurements to determine moisture content must be made at the same time as the measurements for NOx concentration.</td>
</tr>
<tr>
<td>c. Reduce PM emissions by 60 percent or more</td>
<td>i. Select the sampling port location and the number of traverse points;</td>
<td>(1) Method 1 or 1A of 40 CFR part 60, appendix A-1</td>
<td>(a) Sampling sites must be located at the inlet and outlet of the control device.</td>
</tr>
<tr>
<td>d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust</td>
<td>ii. Measure O₂ at the inlet and outlet of the control device;</td>
<td>(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2</td>
<td>(b) Measurements to determine O₂ concentration must be made at the same time as the measurements for PM concentration.</td>
</tr>
<tr>
<td></td>
<td>iii. If necessary, measure moisture content at the inlet and outlet of the control device; and</td>
<td>(3) Method 4 of 40 CFR part 60, appendix A-3</td>
<td>(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.</td>
</tr>
<tr>
<td></td>
<td>iv. Measure PM at the inlet and outlet of the control device.</td>
<td>(4) Method 5 of 40 CFR part 60, appendix A-3</td>
<td>(d) PM concentration must be at 15 percent O₂, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.</td>
</tr>
<tr>
<td></td>
<td>i. Select the sampling port location and the number of traverse points;</td>
<td>(1) Method 1 or 1A of 40 CFR part 60, appendix A-1</td>
<td>(a) If using a control device, the sampling site must be located at the outlet of the control device.</td>
</tr>
<tr>
<td></td>
<td>ii. Determine the O₂ concentration of the stationary internal</td>
<td>(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-3</td>
<td>(b) Measurements to determine O₂ concentration must be made at the same time as the</td>
</tr>
</tbody>
</table>
combustion engine exhaust at the sampling port location; A-2 measurements for PM concentration.

iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and (3) Method 4 of 40 CFR part 60, appendix A-3 (c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.

iv. Measure PM at the exhaust of the stationary internal combustion engine. (4) Method 5 of 40 CFR part 60, appendix A-3 (d) PM concentration must be at 15 percent O₂, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[79 FR 11251, Feb. 27, 2014]

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

<table>
<thead>
<tr>
<th>General Provisions citation</th>
<th>Subject of citation</th>
<th>Applies to subpart</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>§60.1</td>
<td>General applicability of the General Provisions</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.2</td>
<td>Definitions</td>
<td>Yes</td>
<td>Additional terms defined in §60.4219.</td>
</tr>
<tr>
<td>§60.3</td>
<td>Units and abbreviations</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.4</td>
<td>Address</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.5</td>
<td>Determination of construction or modification</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.6</td>
<td>Review of plans</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.7</td>
<td>Notification and Recordkeeping</td>
<td>Yes</td>
<td>Except that §60.7 only applies as specified in §60.4214(a).</td>
</tr>
<tr>
<td>§60.8</td>
<td>Performance tests</td>
<td>Yes</td>
<td>Except that §60.8 only applies to stationary CI ICE with a displacement of ≥30 liters per cylinder and engines that are not certified.</td>
</tr>
<tr>
<td>§60.9</td>
<td>Availability of information</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.10</td>
<td>State Authority</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.11</td>
<td>Compliance with standards and maintenance requirements</td>
<td>No</td>
<td>Requirements are specified in subpart IIII.</td>
</tr>
<tr>
<td>§60.12</td>
<td>Circumvention</td>
<td>Yes</td>
<td></td>
</tr>
</tbody>
</table>

[As stated in §60.4218, you must comply with the following applicable General Provisions:]
<table>
<thead>
<tr>
<th>§60.13</th>
<th>Monitoring requirements</th>
<th>Yes</th>
<th>Except that §60.13 only applies to stationary CI ICE with a displacement of $\geq 30$ liters per cylinder.</th>
</tr>
</thead>
<tbody>
<tr>
<td>§60.14</td>
<td>Modification</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.15</td>
<td>Reconstruction</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.16</td>
<td>Priority list</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.17</td>
<td>Incorporations by reference</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>§60.18</td>
<td>General control device requirements</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>§60.19</td>
<td>General notification and reporting requirements</td>
<td>Yes</td>
<td></td>
</tr>
</tbody>
</table>
APPENDIX C

Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

SOURCE: 76 FR 15664, Mar. 21, 2011, unless otherwise noted.

WHAT THIS SUBPART COVERS

§63.7480 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

§63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP, except as specified in §63.7491. For purposes of this subpart, a major source of HAP is as defined in §63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in §63.7575.

[78 FR 7162, Jan. 31, 2013]

§63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in §63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in §63.7575, located at a major source.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in §63.2, you commence reconstruction after June 4, 2010, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]
§63.7491  Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part or a natural gas-fired EGU as defined in subpart UUUUU of this part firing at least 85 percent natural gas on an annual heat input basis.

(b) A recovery boiler or furnace covered by subpart MM of this part.

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

(d) A hot water heater as defined in this subpart.

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see §63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

(i) Any boiler or process heater 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 or process heater is provided by regulated gas streams that are subject to another standard.

(j) Temporary boilers and process heaters as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

(l) Any boiler or process heater specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in §63.1200(b) is not covered by Subpart EEE.

(n) Residential boilers as defined in this subpart.


§63.7495  When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by April 1, 2013, or upon startup of your boiler or process heater, whichever is later.
(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in §63.6(i).

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.

(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in §63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of §60.2145(a)(2) and (3) or §60.2710(a)(2) and (3).

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2016, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in §63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

(h) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory after the compliance date of this subpart, you must be in compliance with the applicable existing source provisions of this subpart on the effective date of the fuel switch or physical change.

(i) If you own or operate a new industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory, you must be in compliance with the applicable new source provisions of this subpart on the effective date of the fuel switch or physical change.


**EMISSION LIMITATIONS AND WORK PRACTICE STANDARDS**

§63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters, as defined in §63.7575 are:

(a) Pulverized coal/solid fossil fuel units.
(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

(e) Fluidized bed units designed to burn biomass/bio-based solid.

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

§63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.
(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under §63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate either steam, cogenerate steam with electricity, or both. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate only electricity. Boilers that perform multiple functions (cogeneration and electricity generation) or supply steam to common headers would calculate a total steam energy output using equation 21 of §63.7575 to demonstrate compliance with the output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction on or after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction on or after December 23, 2011 and before April 1, 2013, you may comply with the emission limits in Table 1 or 13 to this subpart until January 31, 2016.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under §63.8(f).

(3) At all times, you must operate and maintain any affected source (as defined in §63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. 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) As provided in §63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in §63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in §63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input
capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with items 5 and 6 of Table 3 to this subpart.


§63.7501 [Reserved]

GENERAL COMPLIANCE REQUIREMENTS

§63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These emission and operating limits apply to you at all times the affected unit is operating except for the periods noted in §63.7500(f).

(b) [Reserved]

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to §63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance stack testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits through the use of CPMS, or with a CEMS or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) 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 design, data collection, and the quality assurance and quality control elements outlined in §63.8(d) and the elements described in paragraphs (d)(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. 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 §63.7525. Using the process described in §63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

(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, accuracy audits, analytical drift).

(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of §63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of §63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of §63.10(c) (as applicable in Table 10 to this subpart), (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.

(e) If you have an applicable emission limit, and you choose to comply using definition (2) of “startup” in §63.7575, you must develop and implement a written startup and shutdown plan (SSP) according to the requirements in Table 3 to this subpart. The SSP must be maintained onsite and available upon request for public inspection.


TESTING, FUEL ANALYSES, AND INITIAL COMPLIANCE REQUIREMENTS

§63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance (stack) testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to §63.7520 and Table 5 to this subpart.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under §63.7521 and Table 6 to this subpart.
(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required
to conduct a fuel analysis of those Gas 1 fuels according to §63.7521 and Table 6 to this subpart. If gaseous
fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those non-Gas 1
gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to
conduct a fuel analysis of those non-Gas 1 fuels according to §63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a
fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this
section.

(3) Establish operating limits according to §63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to §63.7525.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable
emission limits in Tables 1 or 2 or 11 through 13 to this subpart for HCl, mercury, or TSM through fuel
analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your
boiler or process heater according to §63.7521 and Table 6 to this subpart and establish operating limits
according to §63.7530 and Table 8 to this subpart. The fuels described in paragraph (a)(2)(i) and (ii) of this
section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph
(a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers
and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and
operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance
demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a
performance evaluation of your continuous CO monitor, if applicable, according to §63.7525(a). Boilers and
process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard
listed in Tables 1, 2, or 11 through 13 to this subpart, as specified in §63.7525(a), are exempt from the initial
CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this
section.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM
is to conduct a performance test in accordance with §63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in §63.7490), you must complete the initial compliance
demonstrations, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the
compliance date that is specified for your source in §63.7495 and according to the applicable provisions in
§63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must
complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later
than the compliance date specified in §63.7495, except as specified in paragraph (j) of this section. You must
complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date
specified in §63.7495.

(f) For new or reconstructed affected sources (as defined in §63.7490), you must complete the initial
compliance demonstration with the emission limits no later than July 30, 2013 or within 180 days after startup
of the source, whichever is later. If you are demonstrating compliance with an emission limit in Tables 11
through 13 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 1 to
this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than July
29, 2016.
(g) For new or reconstructed affected sources (as defined in §63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in §63.7515(d) following the initial compliance date specified in §63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in §63.7515(d).

(h) For affected sources (as defined in §63.7490) that ceased burning solid waste consistent with §63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. 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.

(i) For an existing EGU that becomes subject after January 31, 2016, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in §63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in §63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 to this subpart, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in §63.7495.

(k) For affected sources, as defined in §63.7490, that switch subcategories consistent with §63.7545(h) after the initial compliance date, you must demonstrate compliance within 60 days of the effective date of the switch, unless you had previously conducted your compliance demonstration for this subcategory within the previous 12 months.


§63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to §63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under §63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 to this subpart) for a pollutant, you must conduct annual
performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 to this subpart).

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to §63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in §63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in §63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in §63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in §63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after April 1, 2013 or the initial startup of the new or reconstructed affected source, whichever is later.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to §63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in §63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level. If sampling is conducted on one day per month, samples should be no less than 14 days apart, but if multiple samples are taken per month, the 14-day restriction does not apply.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to §63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in §63.7550.

(g) For affected sources (as defined in §63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in §63.7540(a)(10)(i) through (vi) and the schedule described in §63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra-low sulfur liquid fuel, you do not need to conduct further performance tests (stack tests or fuel analyses) if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra-low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in §63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in
Tables 1, 2, or 11 through 13 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in §63.7510(a).


§63.7520 What stack tests and procedures must I use?

(a) You must conduct all performance tests according to §63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in §63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 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 at 40 CFR part 60, appendix A-7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

(f) Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7166, Jan. 31, 2013]

§63.7521 What fuel analyses, fuel specification, and procedures must I use?

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) For
purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. 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, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in §63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in §63.7510.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) You must obtain composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material. At a minimum, for demonstrating initial compliance by fuel analysis, you must obtain three composite samples. For monthly fuel analyses, at a minimum, you must obtain a single composite sample. For fuel analyses as part of a performance stack test, as specified in §63.7510(a), you must obtain a composite fuel sample during each performance test run.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.
(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart, for use in Equations 7, 8, and 9 of this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in §63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section, or as an alternative where fuel specification analysis is not practical, you must measure mercury concentration in the exhaust gas when firing only the gaseous fuel to be demonstrated as an other gas 1 fuel in the boiler or process heater according to the procedures in Table 6 to this subpart.
(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

(g) You must develop a site-specific fuel analysis plan for other gas 1 fuels according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in §63.7510.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the identification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart. When using a fuel supplier's fuel analysis, the owner or operator is not required to submit the information in §63.7521(g)(2)(iii).

(h) You must obtain a single fuel sample for each fuel type for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.
§63.7522 Can I use emissions averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of §63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart as specified in paragraph (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

(1) You may average units using a CEMS or PM CPMS for demonstrating compliance.

(2) For mercury and HCl, averaging is allowed as follows:

(i) You may average among units in any of the solid fuel subcategories.

(ii) You may average among units in any of the liquid fuel subcategories.

(iii) You may average among units in a subcategory of units designed to burn gas 2 (other) fuels.

(iv) You may not average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn gas 2 (other) subcategories.

(3) For PM (or TSM), averaging is only allowed between units within each of the following subcategories and you may not average across subcategories:

(i) Units designed to burn coal/solid fossil fuel.

(ii) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(iii) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

(iv) Fluidized bed units designed to burn biomass/bio-based solid.

(v) Suspension burners designed to burn biomass/bio-based solid.

(vi) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(vii) Fuel Cells designed to burn biomass/bio-based solid.

(viii) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(ix) Units designed to burn heavy liquid fuel.

(x) Units designed to burn light liquid fuel.
(xi) Units designed to burn liquid fuel that are non-continental units.

(xii) Units designed to burn gas 2 (other) gases.

(c) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on April 1, 2013 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on April 1, 2013.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 to this subpart at all times the affected units are subject to numeric emission limits following the compliance date specified in §63.7495.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis.

(1) You must use Equation 1a or 1b or 1c of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis, use Equation 1b if you are complying with the emission limits on a steam generation (output) basis, and use Equation 1c if you are complying with the emission limits on a electric generation (output) basis.

\[
AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \frac{(Er \times Hm)}{\sum_{i=1}^{n} Hm} \quad (Eq. \ 1a)
\]

Where:

\(AveWeightedEmissions\) = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

\(Er\) = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, \(i\), in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c).

\(Hm\) = Maximum rated heat input capacity of unit, \(i\), in units of million Btu per hour.

\(n\) = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

\[
AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \frac{(Er \times So)}{\sum_{i=1}^{n} So} \quad (Eq. \ 1b)
\]

Where:

\(AveWeightedEmissions\) = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

\(Er\) = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, \(i\), in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c). If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, \(Eadj\), determined according to §63.7533 for that unit.
So = Maximum steam output capacity of unit, i, in units of million Btu per hour, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

\[
AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left( Er \times So \right) + \sum_{i=1}^{n} So
\]  
(Eq. 1c)

Where:

\text{AveWeightedEmissions} = \text{Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.}

\text{Er} = \text{Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c). If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, Eadj, determined according to §63.7533 for that unit.}

\text{Eo} = \text{Maximum electric generating output capacity of unit, i, in units of megawatt hour, as defined in §63.7575.}

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to using Equation 1a of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart that are in pounds per million Btu of heat input.

\[
AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} \left( Er \times Sm \times Cfi \right) + \sum_{i=1}^{n} \left( Sm \times Cfi \right)
\]  
(Eq. 2)

Where:

\text{AveWeightedEmissions} = \text{Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.}

\text{Er} = \text{Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in §63.7530(c).}

\text{Sm} = \text{Maximum steam generation capacity by unit, i, in units of pounds per hour.}

\text{Cfi} = \text{Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.}

1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in §63.7495. If the affected source elects to collect monthly data for up the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of this section.
For each calendar month, you must use Equation 3a or 3b or 3c of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you are complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual electrical generation for the month if you are complying with the emission limits on an electrical generation (output) basis.

\[ \text{AveWeightedEmissions} = 1.1 \times \frac{\sum_{i=1}^{n} (E_r \times H_b)}{\sum_{i=1}^{n} H_b} \]  \quad (\text{Eq. 3a})

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input, for that calendar month.

\( E_r \) = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

\( H_b \) = The heat input for that calendar month to unit, i, in units of million Btu.

\( n \) = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

\[ \text{AveWeightedEmissions} = 1.1 \times \frac{\sum_{i=1}^{n} (E_r \times S_o)}{\sum_{i=1}^{n} S_o} \]  \quad (\text{Eq. 3b})

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.

\( S_o \) = The steam output for that calendar month from unit, i, in units of million Btu, as defined in §63.7575.

\( n \) = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

\[ \text{AveWeightedEmissions} = 1.1 \times \frac{\sum_{i=1}^{n} (E_r \times E_o)}{\sum_{i=1}^{n} E_o} \]  \quad (\text{Eq. 3c})

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.

\( E_r \) = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to §63.7533, use the adjusted emission level for that unit, \( E_{adj} \), determined according to §63.7533 for that unit.

\( S_o \) = The steam output for that calendar month from unit, i, in units of million Btu, as defined in §63.7575.

\( n \) = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.
Eo = The electric generating output for that calendar month from unit, i, in units of megawatt hour, as defined in §63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3a of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

\[ \text{AveWeightedEmissions} = 1.1 \times \sum_{i=1}^{n} \left( \frac{E_r \times S_a \times C_f}{\sum_{i=1}^{n} \left( S_a \times C_f \right)} \right) \]  

Where:

AveWeightedEmissions = average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input for that calendar month.

E_r = Emission rate (as determined during the most recent compliance demonstration of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

S_a = Actual steam generation for that calendar month by boiler, i, in units of pounds.

C_f = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.

1.1 = Required discount factor.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the average weighted emission rate determined under paragraph (f)(1) or (2) of this section for each calendar month. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current calendar month and the previous 11 calendar months.

\[ \text{Eavg} = \sum_{i=1}^{12} \text{ER}_i \]  

Where:

Eavg = 12-month rolling average emission rate, (pounds per million Btu heat input)

ER_i = Monthly weighted average, for calendar month “i” (pounds per million Btu heat input), as calculated by paragraph (f)(1) or (2) of this section.

(g) You must develop, and submit upon request to the applicable Administrator for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

(1) If requested, you must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:
(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of January 31, 2013 and the date on which you are requesting emission averaging to commence;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple boilers or process heaters, the owner or operator must identify each boiler or process heater;

(iv) The test plan for the measurement of PM (or TSM), HCl, or mercury emissions in accordance with the requirements in §63.7520;

(v) The operating parameters to be monitored for each control system or device consistent with §63.7500 and Table 4, and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to §63.7525, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the Administrator, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating load conditions. Following each compliance demonstration and until the next compliance demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(3) If submitted upon request, the Administrator shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable Administrator shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources; or

(ii) The inclusion of any emission source other than an existing unit in the same subcategories.
(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategory, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) For all other groups of units subject to the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, the owner or operator may elect to:

1. Conduct performance tests according to procedures specified in §63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.

\[ E_n = \sum_{i=1}^{n} (E_{Li} \times H_i) + \sum_{i=1}^{n} H_i \]  

(Eq. 6)

Where:

- \( E_n \) = HAP emission limit, pounds per million British thermal units (lb/MMBtu) or parts per million (ppm).
- \( E_{Li} \) = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu or ppm.
- \( H_i \) = Heat input from unit i, MMBtu.

2. Conduct performance tests according to procedures specified in §63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and

3. Meet the applicable operating limit specified in §63.7540 and Table 8 to this subpart for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategories subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.


§63.7525   What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in §63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen (or carbon dioxide (CO₂)) according to the procedures in paragraphs (a)(1) through (6) of this section.
(1) Install the CO CEMS and oxygen (or CO2) analyzer by the compliance date specified in §63.7495. The CO and oxygen (or CO2) levels shall be monitored at the same location at the outlet of the boiler or process heater. An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the CO emissions limit be determined using CO2 as a diluent correction in place of oxygen at 3 percent. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3 percent oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B; part 75 of this chapter (if an CO analyzer is used); the site-specific monitoring plan developed according to §63.7505(d); and the requirements in §63.7540(a)(8) and paragraph (a) of this section. Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to §63.7505(d), and the requirements in §63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

(i) You must conduct a performance evaluation of each CO CEMS according to the requirements in §63.8(e) and according to Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B.

(ii) During each relative accuracy test run of the CO CEMS, you must collect emission data for CO concurrently (or within a 30- to 60-minute period) by both the CO CEMS and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A-4. The relative accuracy testing must be at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with §63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(vi) When CO2 is used to correct CO emissions and CO2 is measured on a wet basis, correct for moisture as follows: Install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases, in order to correct the measured hourly volumetric flow rates for moisture when calculating CO concentrations. The following continuous moisture monitoring systems are acceptable: A continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O2 both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, i.e., a psychrometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and reporting both the raw data (e.g., hourly average wet-and dry basis O2 values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.
(3) Complete a minimum of one cycle of CO and oxygen (or CO₂) CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen (or CO₂) data concurrently. Collect at least four CO and oxygen (or CO₂) CEMS data values representing 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.

(4) Reduce the CO CEMS data as specified in §63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen (or corrected to an CO₂ percentage determined to be equivalent to 3 percent oxygen) from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19-19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A-7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in §63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in §63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in §63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (e.g., bag leak detectors, ESP secondary power, and PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.7505(d), the requirements in §63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must have a documented detection limit of 0.5 milligram per actual cubic meter, or less.
For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in §63.7535(a) through (d). Express the PM CPMS output as milliamps.

Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.7505(d), the requirements in §63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of §60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30- to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A-3 or Method 17 at 40 CFR part 60, appendix A-6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA’s Central Data Exchange by using the Electronic Reporting Tool (see http://www.epa.gov/ttn/chief/ert/erttool.html).

For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in §63.7535(a) through (d).

Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in §63.7495.

Each COMS must be installed, operated, and maintained according to Performance Specification 1 at appendix B to part 60 of this chapter.
(2) You must conduct a performance evaluation of each COMS according to the requirements in §63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter.

(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. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

(7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in §63.7495.

   (1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

   (2) You must operate the monitoring system as specified in §63.7535(b), and comply with the data calculation requirements specified in §63.7535(c).

   (3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in §63.7535(d).

   (4) You must determine the 30-day rolling average of all recorded readings, except as provided in §63.7535(c).

   (5) You must record the results of each inspection, calibration, and validation check.

   (e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.

   (1) You must install the flow sensor and other necessary equipment in a position that provides a representative flow.

   (2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.
(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

1. Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (e.g., PM scrubber pressure drop).

2. Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

3. Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

4. Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (e.g., check for pressure tap pluggage daily).

5. Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

6. If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in your monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.

1. Install the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

2. Ensure the sample is properly mixed and representative of the fluid to be measured.

3. Calibrate the pH monitoring system in accordance with your monitoring plan and according to the manufacturer's instructions. Clean the pH probe at least once each process operating day. Maintain on-site documentation that your calibration frequency is sufficient to maintain the specified accuracy of your device.

4. Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

1. Install sensors to measure (secondary) voltage and current to the precipitator collection plates.
(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CPMS and elect to 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 (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see §63.14).

(3) Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

(6) Where multiple bag leak detectors are required, the system's instrumentation and alert may be shared among detectors.

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date a final performance specification for a HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.
(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in §63.7540(a)(14) for a mercury CEMS and §63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A-7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect 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.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM, mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide (SO₂) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you elect to use an SO₂ CEMS to demonstrate continuous compliance with the HCl emission limit, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to either part 60 or part 75 of this chapter.

(1) The SO₂ CEMS must be installed by the compliance date specified in §63.7495.

(2) For on-going quality assurance (QA), the SO₂ CEMS must meet either the applicable daily and quarterly requirements in Procedure 1 of appendix F of part 60 or the applicable daily, quarterly, and
semianual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with
the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75
of this chapter if the SO2 CEMS has a span value of 30 ppm or less.

3 For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or
180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance
evaluation shall be completed no later than July 29, 2016.

4 For purposes of collecting SO2 data, you must operate the SO2 CEMS as specified in §63.7535(b).
You must use all the data collected during all periods in calculating data averages and assessing compliance,
except that you must exclude certain data as specified in §63.7535(c). Periods when SO2 data are unavailable
may constitute monitoring deviations as specified in §63.7535(d).

5 Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

6 Use only unadjusted, quality-assured SO2 concentration values in the emissions calculations; do not
apply bias adjustment factors to the part 75 SO2 data and do not use part 75 substitute data values.


§63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and
work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting
initial performance tests and fuel analyses and establishing operating limits, as applicable, according to
§63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct
a fuel analysis is not applicable for units that burn a single type of fuel, as specified by §63.7510(a)(2). If
applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and
CPMS) according to §63.7525.

(b) If you demonstrate compliance through performance stack testing, you must establish each site-
specific operating limit in Table 4 to this subpart that applies to you according to the requirements in §63.7520,
Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses
according to §63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1)
through (3) of this section, as applicable, and as specified in §63.7510(a)(2). (Note that §63.7510(a)(2)
exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show
that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results
of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new
fuel(s).

1 You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis
according to the procedures in paragraphs (b)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater
that has the highest content of chlorine.

(ii) During the fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input
for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the
average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.
\[ Cl_{input} = \sum_{i=1}^{n} \left( Ci \times Qi \right) \quad (Eq. 7) \]

Where:

\( Cl_{input} \) = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

\( Ci \) = Arithmetric average concentration of chlorine in fuel type, \( i \), analyzed according to §63.7521, in units of pounds per million Btu.

\( Qi \) = Fraction of total heat input from fuel type, \( i \), based on the fuel mixture that has the highest content of chlorine during the initial compliance test. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of “1” for \( Qi \). For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

\( n \) = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial fuel analysis using the procedures in paragraphs (b)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

\[ Mercury_{input} = \sum_{i=1}^{n} \left( HGi \times Qi \right) \quad (Eq. 8) \]

Where:

\( Mercury_{input} \) = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

\( HGi \) = Arithmetric average concentration of mercury in fuel type, \( i \), analyzed according to §63.7521, in units of pounds per million Btu.

\( Qi \) = Fraction of total heat input from fuel type, \( i \), based on the fuel mixture that has the highest mercury content during the initial compliance test. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of “1” for \( Qi \). For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

\( n \) = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.
(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned \((Q_i)\) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned \((TSM_i)\).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

\[
TSM_{\text{input}} = \sum_{i=1}^{n} (TSM_i \times Q_i) \quad \text{(Eq. 9)}
\]

Where:

- \(TSM_{\text{input}}\) = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.
- \(TSM_i\) = Arithmetic average concentration of TSM in fuel type, \(i\), analyzed according to §63.7521, in units of pounds per million Btu.
- \(Q_i\) = Fraction of total heat input from fuel type, \(i\), based on the fuel mixture that has the highest content of TSM during the initial compliance test. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of “1” for \(Q_i\). For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.
- \(n\) = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in §63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(I) Your PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(2) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument...
capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(3) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(1) through (4) of this section.

(1) Determine your instrument zero output with one of the following procedures:

(i) Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(ii) Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(iii) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(iv) If none of the steps in paragraphs (b)(4)(ii)(B)(1)(i) through (iii) of this section are possible, you must use a zero output value provided by the manufacturer.

(2) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

\[
X = \frac{1}{n} \sum_{i=1}^{n} X_i, \quad Y = \frac{1}{n} \sum_{i=1}^{n} Y_i \quad \text{(Eq. 10)}
\]

Where:

\( X_i \) = the PM CPMS data points for the three runs constituting the performance test,

\( Y_i \) = the PM concentration value for the three runs constituting the performance test, and

\( n \) = the number of data points.

(3) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

\[
R = \frac{Y}{(X - z)} \quad \text{(Eq. 11)}
\]

Where:
R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y_{\text{i}} = the three run average lb/MMBtu PM concentration,

X_{\text{i}} = the three run average milliamp output from you PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

\begin{equation}
O_{\text{i}} = \frac{\text{L} + \text{z}}{R} \tag{Eq. 12}
\end{equation}

Where:

\( O_{\text{i}} \) = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = your source emission limit expressed in lb/MMBtu,

z = your instrument zero in milliamps, determined from (B)(i), and

R = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

(D) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

\begin{equation}
30-\text{day} = \frac{\sum_{i=1}^{n} H_{\text{pm}}}{n} \tag{Eq. 14}
\end{equation}

Where:

30-day = 30-day average.
Hpvi = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 30 operating days.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Tables 1, 2, or 11 through 13 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers (“back half”) of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the “back half” for other purposes.

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instrument's primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in §63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iv) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(v) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vii) The operating limit for boilers or process heaters 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 §63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.

(viii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

(ix) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO₂ CEMS is to install and operate the SO₂ according to the requirements in
§63.7525(m) establish a maximum SO2 emission rate equal to the highest hourly average SO2 measurement during the most recent three-run performance test for HCl.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to §63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of this section.

\[
P_{90} = \text{mean} + (SD \times t) \quad (\text{Eq. 15})
\]

Where:

\( P_{90} \) = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.

\( t \) = t distribution critical value for 90th percentile \( t_{0.1} \) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

\[
HCl = \sum_{i=1}^{n} (Ci_{90} \times Qi \times 1.028) \quad (\text{Eq. 16})
\]

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

\( Ci_{90} \) = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

\( Qi \) = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of “1” for \( Qi \). For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

\( n \) = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.
Mercury = \sum_{i=1}^{n} (Hgi90 \times Qi) \quad \text{(Eq. 17)}

Where:

Mercury = \text{Mercury emission rate from the boiler or process heater in units of pounds per million Btu.}

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = \text{Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of “1” for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.}

n = \text{Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.}

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

\text{Metals} = \sum_{i=1}^{n} (TSMi90i \times Qi) \quad \text{(Eq. 18)}

Where:

Metals = \text{TSM emission rate from the boiler or process heater in units of pounds per million Btu.}

TSMi90i = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 15 of this section.

Qi = \text{Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest TSM content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of “1” for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.}

n = \text{Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.}

(d)[Reserved]

(e) You must include with the Notification of Compliance Status a signed certification that either the energy assessment was completed according to Table 3 to this subpart, and that the assessment is an accurate depiction of your facility at the time of the assessment, or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.

(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e).

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in §63.7575, you must conduct an initial fuel specification analyses according to §63.7521(f) through (i) and according to the frequency listed in §63.7540(c) and maintain records of the results of the testing as outlined in §63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and
shutdown, you must only follow the work practice standards according to items 5 and 6 of Table 3 of this subpart.

(i) If you opt to comply with the alternative SO$_2$ CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

1. Has a system using wet scrubber or dry sorbent injection and SO$_2$ CEMS installed on the unit; and

2. At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with §63.7500(a)(3); and

3. You establish a unit-specific maximum SO$_2$ operating limit by collecting the maximum hourly SO$_2$ emission rate on the SO$_2$ CEMS during the paired 3-run test for HCl. The maximum SO$_2$ operating limit is equal to the highest hourly average SO$_2$ concentration measured during the HCl performance test.


§63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to §63.7522(e) and for demonstrating monthly compliance according to §63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at: http://www.epa.gov/ttn/atw/boiler/boilerpg.html.

(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (i.e., fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.

1. The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

2. Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).

3. Document all uses of energy from the affected boiler. Use the most recent data available.

4. Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.
(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) For all points included in calculating emissions credits, the owner or operator shall:

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

\[ ECredits = \sum \left( \frac{EIS_{actual}}{EI_{baseline}} \right) + EI_{baseline} \]  \hspace{1cm} (Eq. 19)

Where:

\( ECredits \) = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

\( EIS_{actual} \) = Energy Input Savings for each energy conservation measure, \( i \), implemented for an affected boiler, million Btu per year.

\( EI_{baseline} \) = Energy Input baseline for the affected boiler, million Btu per year.

\( n \) = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.
(e) The emissions rate as calculated using Equation 20 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 to this subpart at all times the affected unit is subject to numeric emission limits, following the compliance date specified in §63.7495.

(f) You must use Equation 20 of this section to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

\[ E_{\text{adj}} = E_m \times (1 - E\text{Credits}) \]

Where:

- \( E_{\text{adj}} \) = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.
- \( E_m \) = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.
- \( E\text{Credits} \) = Efficiency credits from Equation 19 for the affected boiler.

(g) As part of each compliance report submitted as required under §63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.


**CONTINUOUS COMPLIANCE REQUIREMENTS**

§63.7535 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 §63.7505(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater 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), and required monitoring system quality assurance or 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 recorded during periods of startup and shutdown, 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 control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.
(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods of startup and shutdown, when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your semi-annual report.


§63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

1(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in §63.7555(d), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Equal to or lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Equal to or lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 16 of §63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.
(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 16 of §63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of §63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of §63.7530 are greater than the maximum chlorine input level established 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 §63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in §63.7510(a)(2)(i) through (iii).

(5) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel, you must recalculate the maximum mercury input using Equation 8 of §63.7530. If the results of recalculating the maximum mercury input using Equation 8 of §63.7530 are higher than the maximum mercury input level established 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 §63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 17 of §63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 8 of §63.7530. If the results of recalculating the maximum mercury input using Equation 8 of §63.7530 are higher than the maximum mercury input level established 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 §63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) 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 alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no 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 alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.
(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 13 to this subpart at all times the affected unit is subject to numeric emission limits.

(iii) Keep records of CO levels according to §63.7555(b).

(iv) You must record and make available upon request results of CO CEMS performance audits, dates and duration of periods when the CO CEMS is out of control to completion of the corrective actions necessary to return the CO CEMS to operation consistent with your site-specific monitoring plan.

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify, operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in §63.7505(d).

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. You must conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. This frequency does not apply to limited-use boilers and process heaters, as defined in §63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) 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). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NOx requirement to which the unit is subject;

(v) 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; and
(vi) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) 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 or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, 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 used by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in §63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up.

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for mercury CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for mercury CEMS. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date a final performance specification for an HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.
(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for HCl CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for HCl CEMS. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 9 of §63.7530. If the results of recalculating the maximum TSM input using Equation 9 of §63.7530 are higher than the maximum total selected input level established 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 §63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 18 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 18 of §63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis.
(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 13 of this subpart.

(i) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (v) of this section.

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater operating hours in assessing the compliance with your operating limit except:
(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(vii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in §63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in §63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in §63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in §63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in §63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in §63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in §63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

(d) For startup and shutdown, you must meet the work practice standards according to items 5 and 6 of Table 3 of this subpart.
§63.7541  How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (5) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.7522(f) and (g).

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) and (ii) of this section.

(i) For each existing unit participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling average parameter values consistent with the approved monitoring plan.

(5) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of this section is a deviation.

§63.7545  What notifications must I submit and when?

(a) You must submit to the Administrator all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in §63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013.

(c) As specified in §63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.
(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in §63.7530, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8) of this section, as applicable. If you are not required to conduct an initial compliance demonstration as specified in §63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8) of this section and must be submitted within 60 days of the compliance date specified at §63.7495(b).

1. A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under §241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of §241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

2. Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

   (i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

   (ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

   (iii) Identification of whether you are complying the arithmetic mean of all valid hours of data from the previous 30 operating days or of the previous 720 hours. This identification shall be specified separately for each operating parameter.

3. A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 13 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

4. Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

5. Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

   (i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

   (ii) [Reserved]
(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

(8) In addition to the information required in §63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) “This facility completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in §63.7540(a)(10)(i) through (vi).”

(ii) “This facility has had an energy assessment performed according to §63.7530(c).”

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: “No secondary materials that are solid waste were combusted in any affected unit.”

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in §63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

(g) 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, as defined in §63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories 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.
(h) If you have switched fuels or made a physical change to the boiler or process heater and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date upon which the fuel switch or physical change occurred.


§63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct subsequent annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or Table 4 operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first semi-annual compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.7495. If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for your source in §63.7495.

(2) The first semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in §63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to
70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to the requirements of a tune up you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii) of this section, (xiv) and (xvii) of this section, and paragraph (c)(5)(iv) of this section for limited-use boiler or process heater.

(2) If you are complying with the fuel analysis you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (vi), (x), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(3) If you are complying with the applicable emissions limit with performance testing you must submit a compliance report with the information in (c)(5)(i) through (iii), (vi), (vii), (viii), (ix), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(4) If you are complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (iii), (v), (vi), (xi) through (xiii), (xv) through (xviii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with §63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of §63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 16 of §63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of §63.7530, that demonstrates that your source is
still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 17 of §63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of §63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 18 of §63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of §63.7530 or the maximum mercury input operating limit using Equation 8 of §63.7530, or the maximum TSM input operating limit using Equation 9 of §63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§63.7521(f) and 63.7530(g).

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in §63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with §63.7500(a)(3), including actions taken to correct the malfunction.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in §63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values for CEMS (CO, HCl, SO₂, and mercury), 10 day rolling average values for CO CEMS when the limit is expressed as a 10 day instead of 30 day rolling average, and the PM CPMS data.

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.
(xviii) For each instance of startup or shutdown include the information required to be monitored, collected, or recorded according to the requirements of §63.7555(d).

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, or from the work practice standards for periods if startup and shutdown, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in §63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) A brief description of the source for which there was a deviation.

(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f)-(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.
Within 60 days after the date of completing each performance test (as defined in §63.2) required by this subpart, you must submit the results of the performance tests, including any fuel analyses, following the procedure specified in either paragraph (h)(1)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (http://www.epa.gov/ttn/chief/ert/index.html), you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/).) Performance test data must be submitted in a file format generated through use of the EPA's ERT or an electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in §63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation (as defined in 63.2), you must submit the results of the performance evaluation following the procedure specified in either paragraph (h)(2)(i) or (ii) of this section.

(i) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If you claim that some of the performance evaluation information being transmitted is CBI, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in §63.13.

(3) You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (http://www.epa.gov/ttn/chief/cedri/index.html), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report...
§63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xv).

(2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(viii).

(3) For units in the limited use subcategory, 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 fuel use records for the days the boiler or process heater was operating.

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in §63.10(b)(2)(vii) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in §63.6(h)(7)(i) and (ii).

(3) Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to §241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under §241.3(d)(1) of this chapter. 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 satisfy the definition of processing in §241.2 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 of this chapter, you must keep records documenting that the material is listed as a non-waste
under §241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the
Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to
maintain the records described in this paragraph (d)(2).

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using
Equation 7 of §63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for
sources that demonstrate compliance through performance testing. For sources that demonstrate compliance
through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using
Equation 16 of §63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting
documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine
fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and
process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel
input, or HCl emission rate, for each boiler and process heater.

(4) A copy of all calculations and supporting documentation of maximum mercury fuel input, using
Equation 8 of §63.7530, that were done to demonstrate continuous compliance with the mercury emission limit
for sources that demonstrate compliance through performance testing. For sources that demonstrate
compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury
emission rates, using Equation 17 of §63.7530, that were done to demonstrate compliance with the mercury
emission limit. Supporting documentation should include results of any fuel analyses and basis for the
estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel
analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However,
you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(5) If, consistent with §63.7515(b), you choose to stack test less frequently than annually, you must keep
a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the
applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 13 to this subpart, less
than the applicable emission limit), and document that there was no change in source operations including fuel
composition and operation of air pollution control equipment that would cause emissions of the relevant
pollutant to increase within the past year.

(6) Records of the occurrence and duration of each malfunction of the boiler or process heater, or of the
associated air pollution control and monitoring equipment.

(7) Records of actions taken during periods of malfunction to minimize emissions in accordance with the
general duty to minimize emissions in §63.7500(a)(3), including corrective actions to restore the
malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual
manner of operation.

(8) A copy of all calculations and supporting documentation of maximum TSM fuel input, using
Equation 9 of §63.7530, that were done to demonstrate continuous compliance with the TSM emission limit
for sources that demonstrate compliance through performance testing. For sources that demonstrate
compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission
rates, using Equation 18 of §63.7530, that were done to demonstrate compliance with the TSM emission limit.
Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum
TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and
process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input,
or TSM emission rates, for each boiler and process heater.
(9) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(10) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

(11) For each startup period, for units selecting paragraph (2) of the definition of “startup” in §63.7575 you must maintain records of the time that clean fuel combustion begins; the time when you start feeding fuels that are not clean fuels; the time when useful thermal energy is first supplied; and the time when the PM controls are engaged.

(12) If you choose to rely on paragraph (2) of the definition of “startup” in §63.7575, for each startup period, you must maintain records of the hourly steam temperature, hourly steam pressure, hourly steam flow, hourly flue gas temperature, and all hourly average CMS data (e.g., CEMS, PM CPMS, COMS, ESP total secondary electric power input, scrubber pressure drop, scrubber liquid flow rate) collected during each startup period to confirm that the control devices are engaged. In addition, if compliance with the PM emission limit is demonstrated using a PM control device, you must maintain records as specified in paragraphs (d)(12)(i) through (iii) of this section.

(i) For a boiler or process heater with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(ii) For a boiler or process heater with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(iii) For a boiler or process heater with a wet scrubber needed for filterable PM control, record the scrubber's liquid flow rate and the pressure drop during each hour of startup.

(13) If you choose to use paragraph (2) of the definition of “startup” in §63.7575 and you find that you are unable to safely engage and operate your PM control(s) within 1 hour of first firing of non-clean fuels, you may choose to rely on paragraph (1) of definition of “startup” in §63.7575 or you may submit to the delegated permitting authority a request for a variance with the PM controls requirement, as described below.

(i) The request shall provide evidence of a documented manufacturer-identified safety issue.

(ii) The request shall provide information to document that the PM control device is adequately designed and sized to meet the applicable PM emission limit.

(iii) In addition, the request shall contain documentation that:

(A) The unit is using clean fuels to the maximum extent possible to bring the unit and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel;

(B) The unit has explicitly followed the manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) Identifies with specificity the details of the manufacturer's statement of concern.

(iv) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.
(e) If you elect to average emissions consistent with §63.7522, you must additionally keep a copy of the emission averaging implementation plan required in §63.7522(g), all calculations required under §63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with §63.7541.

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to §63.7533, you must keep a copy of the Implementation Plan required in §63.7533(d) and copies of all data and calculations used to establish credits according to §63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by §63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.


§63.7560 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

OTHER REQUIREMENTS AND INFORMATION

§63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the 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 (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section
are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission limits and work practice standards in §63.7500(a) and (b) under §63.6(g), except as specified in §63.7555(d)(13).

(2) Approval of major change to test methods in Table 5 to this subpart under §63.7(e)(2)(ii) and (f) and as defined in §63.90, and alternative analytical methods requested under §63.7521(b)(2).

(3) Approval of major change to monitoring under §63.8(f) and as defined in §63.90, and approval of alternative operating parameters under §§63.7500(a)(2) and 63.7522(g)(2).

(4) Approval of major change to recordkeeping and reporting under §63.10(e) and as defined in §63.90.


§63.7575 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 the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

30-day rolling average means the arithmetic mean of the previous 720 hours of valid CO CEMS data. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent. For parameters other than CO, 30-day rolling average means either the arithmetic mean of all valid hours of data from 30 successive operating days or the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating.

Annual capacity factor means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Average annual heat input rate means total heat input divided by the hours of operation 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.
Benchmark means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

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 or bio-based solid fuel means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue; 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.

Blast furnace gas fuel-fired boiler or process heater means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total annual gas volume from blast furnace gas.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam 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 are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

Clean dry biomass means any biomass-based solid fuel that have not been painted, pigment-stained, or pressure treated, does not contain contaminants at concentrations not normally associated with virgin biomass materials and has a moisture content of less than 20 percent and is not a solid waste.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by 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 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 (6,000 Btu per pound) on a dry basis.

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, 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.

**Cost-effective energy conservation measure** means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.

**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 or downtime.

**Deviation.** (1) **Deviation** 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.

**Dioxins/furans** means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

**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 §60.14).

**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.

**Dutch oven** means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

**Efficiency credit** means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

**Electric utility steam generating unit (EGU)** means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) 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 MWe 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, 2012.

_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 and process heaters with a combined heat input capacity of less than 0.3 trillion Btu (TBtu) per year 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), process heater(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, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment.

2. The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of 0.3 to 1.0 TBtu/year 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), process heater(s), and any on-site energy use system(s) accounting for at least 33 percent of the energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour on-site energy assessment.

3. The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity greater than 1.0 TBtu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr 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), process heater(s), and any on-site energy use system(s) accounting for at least 20 percent of the energy (e.g., steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

4. The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy production 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 practices_ means the 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.

_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* includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: 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 other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

*Equivalent* means the following only as this term is used in Table 6 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 metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. 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 metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, HCl) determinative or analytical 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 and has a published detection limit equal or lower than the methods listed in Table 6 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 boiler with an integrated fluidized bed heat exchanger** means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

**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.

**Fossil fuel** means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

**Fuel cell** means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

**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 fuel** includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are exempted from this definition.

**Heat input** means heat derived from combustion of fuel in a boiler or process heater 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, etc.

**Heavy liquid** includes residual oil and any other liquid fuel not classified as a light liquid.

**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.

**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/bio-based solid fuel and 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 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

**Hybrid suspension grate boiler** means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis as demonstrated by monthly fuel analysis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

**Industrial boiler** means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.
Light liquid includes distillate oil, biodiesel, or vegetable oil.

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable annual capacity factor of no more than 10 percent.

Liquid fuel includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, and vegetable oil.

Load fraction means the actual heat input of a boiler or process heater 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). For boilers and process heaters that co-fire natural gas or refinery gas with a solid or liquid fuel, the load fraction is determined by the actual heat input of the solid or liquid fuel divided by heat input of the solid or liquid fuel fired during the performance test (e.g., if the performance test was conducted at 100 percent solid fuel firing, for 100 percent load firing 50 percent solid fuel and 50 percent natural gas the load fraction is 0.5).

Major source for oil and natural gas production facilities, as used in this subpart, shall have the same meaning as in §63.2, except that:

1. Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

2. Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

3. For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

Metal process furnaces are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

Million Btu (MMBtu) means one million British thermal units.

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum pressure drop means the lowest hourly average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.
Minimum scrubber effluent pH means the lowest hourly average sorbent liquid pH measured at the inlet to the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 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 7 to this subpart during the most recent performance 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 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion not using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, 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 7 to this subpart during the most recent performance 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 in ASTM D1835 (incorporated by reference, see §63.14); 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 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.

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 or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period. For calculating rolling average emissions, an operating day does not include the hours of operation during startup or shutdown.
Other combustor means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer’s recommendations.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device over its operating load range. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller or draft 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 or process heater 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.

Pile burner means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

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. A device combusting solid waste, as defined in §241.3 of this chapter, is not a process heater 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. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

Pulverized coal boiler means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.

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.

(vi) 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.

Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.
Regulated gas stream means an offgas stream that is routed to a boiler or process heater 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.

Rolling average means the average of all data collected during the applicable averaging period. For demonstration of compliance with a CO CEMS-based emission limit based on CO concentration a 30-day (10-day) rolling average is comprised of the average of all the hourly average concentrations over the previous 720 (240) operating hours calculated each operating day. To demonstrate compliance on a 30-day rolling average basis for parameters other than CO, you must indicate the basis of the 30-day rolling average period you are using for compliance, as discussed in §63.7545(e)(2)(iii). If you indicate the 30 operating day basis, you must calculate a new average value each operating day and shall include the measured hourly values for the preceding 30 operating days. If you select the 720 operating hours basis, you must average of all the hourly average concentrations over the previous 720 operating hours calculated each operating day.

Secondary material means the material as defined in §241.2 of this chapter.

Shutdown means the period in which cessation of operation of a boiler or process heater is initiated for any purpose. Shutdown begins when the boiler or process heater no longer supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes and/or generates electricity or when no fuel is being fed to the boiler or process heater, whichever is earlier. Shutdown ends when the boiler or process heater no longer supplies useful thermal energy (such as steam or heat) for heating, cooling, or process purposes and/or generates electricity, and no fuel is being combusted in the boiler or process heater.

Sloped grate means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

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:
(1) Either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy 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 useful thermal energy from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose, or

(2) The period in which operation of a boiler or process heater is initiated for any purpose. Startup begins with either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy (such as steam or heat) for heating, cooling or process purposes, or producing electricity, or the firing of fuel in a boiler or process heater for any purpose after a shutdown event. Startup ends four hours after when the boiler or process heater supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes, or generates electricity, whichever is earlier.

Steam output means:

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be the appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input (lb per MWh).

(4) For a boiler that performs multiple functions and produces steam to be used for any combination of paragraphs (1), (2), and (3) of this definition that includes electricity generation of paragraph (3) of this definition, the total energy output, in terms of MMBtu of steam output, is the sum of the energy content of steam sent directly to the process and/or used for heating ($S_1$), the energy content of turbine steam sent to process plus energy in electricity according to paragraph (2) of this definition ($S_2$), and the energy content of electricity generated by a electricity only turbine as paragraph (3) of this definition ($MW_{0(3)}$) and would be calculated using Equation 21 of this section. In the case of boilers supplying steam to one or more common heaters, $S_1$, $S_2$, and $MW_{0(3)}$ for each boiler would be calculated based on the its (steam energy) contribution (fraction of total steam energy) to the common heater.

\[ SO_M = S_1 + S_2 + (MW_{0(3)} \times CFn) \]  
(Eq. 21)

Where:

SO_M = Total steam output for multi-function boiler, MMBtu

$S_1$ = Energy content of steam sent directly to the process and/or used for heating, MMBtu

$S_2$ = Energy content of turbine steam sent to the process plus energy in electricity according to (2) above, MMBtu

$MW_{0(3)}$ = Electricity generated according to paragraph (3) of this definition, MWh

CFn = Conversion factor for the appropriate subcategory for converting electricity generated according to paragraph (3) of this definition to equivalent steam energy, MMBtu/MWh

CFn for emission limits for boilers in the unit designed to burn solid fuel subcategory = 10.8

CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal = 11.7
CFn PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass = 12.1

CFn for emission limits for boilers in one of the subcategories of units designed to burn liquid fuel = 11.2

CFn for emission limits for boilers in the unit designed to burn gas 2 (other) subcategory = 6.2

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

Stoker/sloped grate/other unit designed to burn kiln dried biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

Suspension burner means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

Temporary boiler means any gaseous or liquid fuel boiler or process heater 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 or process heater is not a temporary boiler or process heater if any one of the following conditions exists:

1. The equipment is attached to a foundation.
2. The boiler or process heater 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 or process heater that replaces a temporary boiler or process heater 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 within the facility but continues to perform the same or similar function and serve the same electricity, process heat, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Total selected metals (TSM) means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.
Traditional fuel means the fuel as defined in §241.2 of this chapter.

Tune-up means adjustments made to a boiler or process heater in accordance with the procedures outlined in §63.7540(a)(10).

Ultra low sulfur liquid fuel means a distillate oil that has less than or equal to 15 ppm sulfur.

Unit designed to burn biomass/bio-based solid subcategory includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

Unit designed to burn coal/solid fossil fuel subcategory includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

Unit designed to burn heavy liquid subcategory means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

Unit designed to burn light liquid subcategory means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn liquid subcategory.
located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

*Unit designed to burn solid fuel subcategory* means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

*Useful thermal energy* means energy (i.e., steam, hot water, or process heat) that meets the minimum operating temperature, flow, and/or pressure required by any energy use system that uses energy provided by the affected boiler or process heater.

*Vegetable oil* means oils extracted from vegetation.

*Voluntary Consensus Standards or 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.standards.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/), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, + 49 211 6214-230, http://www.vdi.de). 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.

*Waste heat process heater* means an enclosed device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

*Wet scrubber* means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater 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, that is promulgated pursuant to section 112(h) of the Clean Air Act.


**Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters**

As stated in §63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

<table>
<thead>
<tr>
<th>If your boiler or process heater is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>The emissions must not exceed the following emission limits, except during startup and shutdown . . .</th>
<th>Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .</th>
<th>Using this specified sampling volume or test run duration . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Units in all subcategories designed to burn solid fuel.</td>
<td>a. HCl</td>
<td>2.2E-02 lb per MMBtu of heat input</td>
<td>2.5E-02 lb per MMBtu of steam output or 0.28 lb per MWh</td>
<td>For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.</td>
</tr>
<tr>
<td></td>
<td>b. Mercury</td>
<td>8.0E-07 lb per MMBtu of heat input</td>
<td>8.7E-07 lb per MMBtu of steam output or 1.1E-05 lb per MWh</td>
<td>For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784b collect a minimum of 4 dscm.</td>
</tr>
<tr>
<td>2. Units designed to burn coal/solid fossil fuel</td>
<td>a. Filterable PM (or TSM)</td>
<td>1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)</td>
<td>1.1E-03 lb per MMBtu of steam output or 1.4E-02 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 2.9E-04 lb per MWh)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td>3. Pulverized coal boilers designed to burn coal/solid fossil fuel</td>
<td>a. Carbon monoxide (CO) (or CEMS)</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, d 30-day rolling average)</td>
<td>0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>4. Stokers/others designed to burn</td>
<td>a. CO (or CEMS)</td>
<td>130 ppm by volume on a dry basis corrected to 3</td>
<td>0.12 lb per MMBtu of steam output or 1.4 lb per MWh</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>Coal/solid fossil fuel</td>
<td>CO (or CEMS)</td>
<td>Filterable PM (or TSM)</td>
<td>Stokers/sloped grate/others designed to burn wood biomass fuel</td>
<td>CO (or CEMS)</td>
</tr>
<tr>
<td>-----------------------</td>
<td>--------------</td>
<td>------------------------</td>
<td>-----------------------------------------------------------</td>
<td>--------------</td>
</tr>
<tr>
<td>1. Fluidized bed units designed to burn coal/solid fossil fuel</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
</tr>
<tr>
<td>2. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel</td>
<td>0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average</td>
<td>1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average</td>
<td>5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average</td>
<td>1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average</td>
</tr>
<tr>
<td>3. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel</td>
<td>1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average</td>
<td>5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average</td>
<td>4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh</td>
<td>1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average</td>
</tr>
<tr>
<td>4. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel</td>
<td>1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average</td>
<td>5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average</td>
<td>4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh</td>
<td>1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average</td>
</tr>
<tr>
<td>5. Fluidized bed units designed to burn coal/solid fossil fuel</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
</tr>
<tr>
<td>6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel</td>
<td>0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average</td>
<td>1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average</td>
<td>5.8E-01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average</td>
<td>1.2E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average</td>
</tr>
<tr>
<td>7. Stokers/sloped grate/others designed to burn wet biomass fuel</td>
<td>3.0E-02 lb per MMBtu of heat input or (2.6E-05 lb per MMBtu of heat input)</td>
<td>3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh)</td>
<td>3.0E-02 lb per MMBtu of heat input or (2.6E-05 lb per MMBtu of heat input)</td>
<td>3.5E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (2.7E-05 lb per MMBtu of steam output or 3.7E-04 lb per MWh)</td>
</tr>
<tr>
<td>8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel</td>
<td>460 ppm by volume on a dry basis corrected to 3 percent oxygen</td>
<td>460 ppm by volume on a dry basis corrected to 3 percent oxygen</td>
<td>460 ppm by volume on a dry basis corrected to 3 percent oxygen</td>
<td>460 ppm by volume on a dry basis corrected to 3 percent oxygen</td>
</tr>
</tbody>
</table>

Collect a minimum of 250 scf per run.
<p>| 9. Fluidized bed units designed to burn biomass/bio-based solids | a. CO (or CEMS) | 230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average) | 2.2E-01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 9.8E-03 lb per MMBtu of heat input; or (8.3E-05 lb per MMBtu of heat input) | 1.2E-02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E-04 lb per MMBtu of steam output or 1.2E-03 lb per MWh) | Collect a minimum of 3 dscm per run. |
| 10. Suspension burners designed to burn biomass/bio-based solids | a. CO (or CEMS) | 2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average) | 1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input) | 3.1E-02 lb per MMBtu of steam output or 4.2E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh) | Collect a minimum of 2 dscm per run. |
| 11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids | a. CO (or CEMS) | 330 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average) | 3.5E-01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average | 1 hr minimum sampling time. |
| | b. Filterable PM (or TSM) | 3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input) | 4.3E-03 lb per MMBtu of steam output or 4.5E-02 lb per MWh; or (5.2E-05 lb per MMBtu of steam output or 5.5E-04 lb per MWh) | Collect a minimum of 3 dscm per run. |
| 12. Fuel cell units designed to burn biomass/bio-based solids | a. CO | 910 ppm by volume on a dry basis corrected to 3 percent oxygen | 1.1 lb per MMBtu of steam output or 1.0E + 01 lb per MWh | 1 hr minimum sampling time. |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids</td>
<td>b. Filterable PM (or TSM)</td>
<td>2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)</td>
<td>3.0E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (5.1E-05 lb per MMBtu of steam output or 4.1E-04 lb per MWh)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>a. CO (or CEMS)</td>
<td>1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>14. Units designed to burn liquid fuel</td>
<td>b. Filterable PM (or TSM)</td>
<td>2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)</td>
<td>3.3E-02 lb per MMBtu of steam output or 3.7E-01 lb per MWh; or (5.5E-04 lb per MMBtu of steam output or 6.2E-03 lb per MWh)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>a. HCl</td>
<td>4.4E-04 lb per MMBtu of heat input</td>
<td>4.8E-04 lb per MMBtu of steam output or 6.1E-03 lb per MWh</td>
<td>For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.</td>
</tr>
<tr>
<td></td>
<td>b. Mercury</td>
<td>4.8E-07 lb per MMBtu of heat input</td>
<td>5.3E-07 lb per MMBtu of steam output or 6.7E-06 lb per MWh</td>
<td>For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 collect a minimum of 4 dscm.</td>
</tr>
<tr>
<td>15. Units designed to burn heavy liquid fuel</td>
<td>a. CO</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average</td>
<td>0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)</td>
<td>1.5E-02 lb per MMBtu of steam output or 1.8E-01 lb per MWh; or (8.2E-05 lb per MMBtu of steam output or 1.1E-03 lb per MWh)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td>16. Units designed to burn light liquid fuel</td>
<td>a. CO</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average</td>
<td>0.13 lb per MMBtu of steam output or 1.4 lb per MWh</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>Section</td>
<td>Pollutant</td>
<td>Concentration per MMBtu of heat input</td>
<td>Concentration per MMBtu of steam output</td>
<td>Concentration per MWh</td>
</tr>
<tr>
<td>---------</td>
<td>-----------</td>
<td>--------------------------------------</td>
<td>--------------------------------------</td>
<td>----------------------</td>
</tr>
<tr>
<td>17.</td>
<td>CO</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test</td>
<td>0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time</td>
</tr>
<tr>
<td>18.</td>
<td>CO</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen</td>
<td>0.16 lb per MMBtu of steam output or 1.0 lb per MWh</td>
<td>1 hr minimum sampling time</td>
</tr>
<tr>
<td></td>
<td>HCl</td>
<td>1.7E-03 lb per MMBtu of heat input</td>
<td>2.9E-03 lb per MMBtu of steam output or 1.8E-02 lb per MWh</td>
<td>For M26, collect a minimum of 2 dscm per run; for M26A, collect a minimum of 240 liters per run.</td>
</tr>
<tr>
<td></td>
<td>Mercury</td>
<td>7.9E-06 lb per MMBtu of heat input</td>
<td>1.4E-05 lb per MMBtu of steam output or 8.3E-05 lb per MWh</td>
<td>For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784, collect a minimum of 3 dscm.</td>
</tr>
<tr>
<td></td>
<td>PM (or TSM)</td>
<td>6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)</td>
<td>1.2E-02 lb per MMBtu of steam output or 7.0E-02 lb per MWh; or (3.5E-04 lb per MMBtu of steam output or 2.2E-03 lb per MWh)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
</tbody>
</table>

*aIf you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provisions of §63.7515 are met. For all other pollutants that do not*
contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

bIncorporated by reference, see §63.14.

cIf your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before April 1, 2013, you may comply with the emission limits in Tables 11, 12 or 13 to this subpart until January 31, 2016. On and after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

dAn owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO₂ correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO₂ being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.


Table 2 to Subpart DDDDD of Part 63—Emission Limits for Existing Boilers and Process Heaters

As stated in §63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

<table>
<thead>
<tr>
<th>If your boiler or process heater is in this subcategory</th>
<th>For the following pollutants</th>
<th>The emissions must not exceed the following emission limits, except during startup and shutdown</th>
<th>The emissions must not exceed the following alternative output-based limits, except during startup and shutdown</th>
<th>Using this specified sampling volume or test run duration</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Units in all subcategories designed to burn solid fuel</td>
<td>a. HCl</td>
<td>2.2E-02 lb per MMBtu of heat input</td>
<td>2.5E-02 lb per MMBtu of steam output or 0.27 lb per MWh</td>
<td>For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.</td>
</tr>
<tr>
<td></td>
<td>b. Mercury</td>
<td>5.7E-06 lb per MMBtu of heat input</td>
<td>6.4E-06 lb per MMBtu of steam output or 7.3E-05 lb per MWh</td>
<td>For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 collect a minimum of 3 dscm.</td>
</tr>
</tbody>
</table>

2. Units design to burn coal/solid fossil fuel

<p>| a. Filterable PM (or TSM) | 4.0E-02 lb per MMBtu of heat input; or (5.3E-05 lb per MMBtu of heat input) | 4.2E-02 lb per MMBtu of steam output or 4.9E-01 lb per MWh; | Collect a minimum of 2 dscm per run. |</p>
<table>
<thead>
<tr>
<th>Description</th>
<th>CO (or CEMS)</th>
<th>PM (or TSM)</th>
<th>Sampling Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>3. Pulverized coal boilers designed to burn coal/solid fossil fuel</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average</td>
<td>4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam)</td>
<td></td>
</tr>
<tr>
<td>4. Stokers/others designed to burn coal/solid fossil fuel</td>
<td>160 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>0.14 lb per MMBtu of steam output or 1.7 lb per MWh; 3-run average</td>
<td>4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam)</td>
<td></td>
</tr>
<tr>
<td>5. Fluidized bed units designed to burn coal/solid fossil fuel</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average</td>
<td>4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam)</td>
<td></td>
</tr>
<tr>
<td>6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel</td>
<td>140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>1.3E-01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average</td>
<td>4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam)</td>
<td></td>
</tr>
<tr>
<td>7. Stokers/sloped grate/others designed to burn wet biomass fuel</td>
<td>1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average</td>
<td>4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam)</td>
<td></td>
</tr>
</tbody>
</table>

Collect a minimum of 2 dscm per run.
<table>
<thead>
<tr>
<th>8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel</th>
<th>a. CO output or 3.4E-04 lb per MWh)</th>
<th>460 ppm by volume on a dry basis corrected to 3 percent oxygen</th>
<th>4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh)</th>
<th>1 hr minimum sampling time.</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. Filterable PM (or TSM)</td>
<td>3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)</td>
<td>3.7E-01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)</td>
<td>Collect a minimum of 1 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>9. Fluidized bed units designed to burn biomass/bio-based solid</td>
<td>a. CO (or CEMS)</td>
<td>470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>4.6E-01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>b. Filterable PM (or TSM)</td>
<td>1.1E-01 lb per MMBtu of heat input; or (1.2E-03 lb per MMBtu of heat input)</td>
<td>1.4E-01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E-03 lb per MMBtu of steam output or 1.7E-02 lb per MWh)</td>
<td>Collect a minimum of 1 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>10. Suspension burners designed to burn biomass/bio-based solid</td>
<td>a. CO (or CEMS)</td>
<td>2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)</td>
<td>1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>b. Filterable PM (or TSM)</td>
<td>5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)</td>
<td>5.2E-02 lb per MMBtu of steam output or 7.1E-01 lb per MWh; or (6.6E-03 lb per MMBtu of steam output or 9.1E-02 lb per MWh)</td>
<td>Collect a minimum of 2 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid</td>
<td>a. CO (or CEMS)</td>
<td>770 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)</td>
<td>8.4E-01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
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</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>2.8E-01 lb per MMBtu of heat input; or (2.0E-03 lb per MMBtu of heat input)</td>
<td>3.9E-01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E-03 lb per MMBtu of steam output or 2.8E-02 lb per MWh)</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td>12. Fuel cell units designed to burn biomass/bio-based solid</td>
<td>a. CO</td>
<td>1,100 ppm by volume on a dry basis corrected to 3 percent oxygen</td>
<td>2.4 lb per MMBtu of steam output or 12 lb per MWh</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>2.0E-02 lb per MMBtu of heat input; or (5.8E-03 lb per MMBtu of heat input)</td>
<td>5.5E-02 lb per MMBtu of steam output or 12 lb per MWh; or (1.6E-02 lb per MMBtu of steam output or 8.1E-02 lb per MWh)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td>13. Hybrid suspension grate units designed to burn biomass/bio-based solid</td>
<td>a. CO (or CEMS)</td>
<td>3,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>3.5 lb per MMBtu of steam output or 39 lb per MWh; 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>4.4E-01 lb per MMBtu of heat input; or (4.5E-04 lb per MMBtu of heat input)</td>
<td>5.5E-01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E-04 lb per MMBtu of steam output or 6.3E-03 lb per MWh)</td>
<td>Collect a minimum of 1 dscm per run.</td>
</tr>
<tr>
<td>14. Units designed to burn liquid fuel</td>
<td>a. HCl</td>
<td>1.1E-03 lb per MMBtu of heat input</td>
<td>1.4E-03 lb per MMBtu of steam output or 1.6E-02 lb per MWh</td>
<td>For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.</td>
</tr>
<tr>
<td></td>
<td>b. Mercury</td>
<td>2.0E-06 lb per MMBtu of heat input</td>
<td>2.5E-06 lb per MMBtu of steam output or 2.8E-05 lb per MWh</td>
<td>For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784, collect a minimum of 2 dscm.</td>
</tr>
<tr>
<td>15. Units designed to burn heavy liquid fuel</td>
<td>a. CO</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run</td>
<td>0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>Units</td>
<td>CO</td>
<td>Filterable PM (or TSM)</td>
<td>HCl</td>
<td>Mercury</td>
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<tr>
<td>16. Units designed to burn light liquid fuel</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen</td>
<td>6.2E-02 lb per MMBtu of heat input or (2.0E-04 lb per MMBtu of heat input)</td>
<td>7.5E-02 lb per MMBtu of steam output or 8.6E-01 lb per MWh; or (2.5E-04 lb per MMBtu of steam output or 2.8E-03 lb per MWh)</td>
<td>6.7E-03 lb per MMBtu of heat input or (2.1E-04 lb per MMBtu of heat input)</td>
</tr>
<tr>
<td>17. Units designed to burn liquid fuel that are non-continental units</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test</td>
<td>7.9E-03 lb per MMBtu of heat input or (6.2E-05 lb per MMBtu of heat input)</td>
<td>9.6E-03 lb per MMBtu of steam output or 1.1E-01 lb per MWh; or (7.5E-05 lb per MMBtu of steam output or 8.6E-04 lb per MWh)</td>
<td>2.7E-01 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)</td>
</tr>
<tr>
<td>18. Units designed to burn gas 2 (other) gases</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen</td>
<td>2.8E-01 lb per MMBtu of heat input or (8.6E-04 lb per MMBtu of heat input)</td>
<td>3.3E-01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E-03 lb per MMBtu of steam output or 1.2E-02 lb per MWh)</td>
<td>7.9E-06 lb per MMBtu of heat input</td>
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</tr>
</tbody>
</table>
If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provisions of §63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

Incorporated by reference, see §63.14.

An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO₂ correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO₂ being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.


Table 3 to Subpart DDDDD of Part 63—Work Practice Standards

As stated in §63.7500, you must comply with the following applicable work practice standards:

<table>
<thead>
<tr>
<th>If your unit is . . .</th>
<th>You must meet the following . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater</td>
<td>Conduct a tune-up of the boiler or process heater every 5 years as specified in §63.7540.</td>
</tr>
<tr>
<td>2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid</td>
<td>Conduct a tune-up of the boiler or process heater biennially as specified in §63.7540.</td>
</tr>
<tr>
<td>3. A new or existing boiler or process heater without</td>
<td>Conduct a tune-up of the boiler or process heater</td>
</tr>
</tbody>
</table>
a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater annually as specified in §63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.

| 4. An existing boiler or process heater located at a major source facility, not including limited use units | 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. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least one year between January 1, 2008 and the compliance date specified in §63.7495 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 a. to e. appropriate for the on-site technical hours listed in §63.7575:
| 5. An existing or new boiler or process heater subject a. You must operate all CMS during startup. |

| a. A visual inspection of the boiler or process heater system. |
| b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints. |
| c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator. |
| d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage. |
| e. A review of the facility's energy management program and provide recommendations for improvements consistent with the definition of energy management program, if identified. |
| f. A list of cost-effective energy conservation measures that are within the facility's control. |
| g. A list of the energy savings potential of the energy conservation measures identified. |
| h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments. |
to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup

b. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, liquefied petroleum gas, clean dry biomass, and any fuels meeting the appropriate HCl, mercury and TSM emission standards by fuel analysis.

c. You have the option of complying using either of the following work practice standards.
   (1) If you choose to comply using definition (1) of “startup” in §63.7575, once you start firing fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose, OR
   (2) If you choose to comply using definition (2) of “startup” in §63.7575, once you start to feed fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. You must engage and operate PM control within one hour of first feeding fuels that are not clean fuels. You must start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source that require operation of the control devices. You must develop and implement a written startup and shutdown plan, as specified in §63.7505(e).

d. You must comply with all applicable emission limits at all times except during startup and shutdown periods at which time you must meet this work practice. You must collect monitoring data during periods of startup, as specified in §63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in §63.7555.

6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown

You must operate all CMS during shutdown. While firing fuels that are not clean fuels during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR but, in any case, when necessary to comply with other standards applicable to the source that require operation of the control device. If, in addition to the fuel used prior to initiation of
shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, refinery gas, and liquefied petroleum gas.

You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in §63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in §63.7555.

As specified in §63.7555(d)(13), the source may request an alternative timeframe with the PM controls requirement to the permitting authority (state, local, or tribal agency) that has been delegated authority for this subpart by EPA. The source must provide evidence that (1) it is unable to safely engage and operate the PM control(s) to meet the “fuel firing + 1 hour” requirement and (2) the PM control device is appropriately designed and sized to meet the filterable PM emission limit. It is acknowledged that there may be another control device that has been installed other than ESP that provides additional PM control (e.g., scrubber).


Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

As stated in §63.7500, you must comply with the applicable operating limits:

**TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS**

<table>
<thead>
<tr>
<th>When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .</th>
<th>You must meet these operating limits . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Wet PM scrubber control on a boiler or process heater not using a PM CPMS</td>
<td>Maintain the 30-day rolling average pressure drop and the 30-day rolling average liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the performance test demonstrating compliance with the PM emission limitation according to §63.7530(b) and Table 7 to this subpart.</td>
</tr>
<tr>
<td>2. Wet acid gas (HCl) scrubber control on a boiler or process heater not using a HCl CEMS</td>
<td>Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the performance test demonstrating compliance with the HCl emission limitation according to §63.7530(b) and Table 7 to this subpart.</td>
</tr>
<tr>
<td>3. Fabric filter control on a boiler or process heater not using a PM CPMS</td>
<td>a. Maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average); or</td>
</tr>
<tr>
<td></td>
<td>b. Install and operate a bag leak detection system according to §63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period.</td>
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</tr>
<tr>
<td>4. Electrostatic precipitator</td>
<td>b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (i.e., dry ESP). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(b) and Table 7 to this subpart.</td>
</tr>
<tr>
<td>control on a boiler or process heater not using a PM CPMS</td>
<td>a. This option is for boilers and process heaters that operate dry control systems (i.e., an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).</td>
</tr>
<tr>
<td>5. Dry scrubber or carbon injection control on a boiler or process heater not using a mercury CEMS</td>
<td>Maintain the minimum sorbent or carbon injection rate as defined in §63.7575 of this subpart.</td>
</tr>
<tr>
<td>6. Any other add-on air pollution control type on a boiler or process heater not using a PM CPMS</td>
<td>This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).</td>
</tr>
<tr>
<td>7. Performance testing</td>
<td>For boilers and process heaters that demonstrate compliance with a performance test, maintain the 30-day rolling average operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test.</td>
</tr>
<tr>
<td>8. Oxygen analyzer system</td>
<td>For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O₂ analyzer system as specified in §63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the CO performance test, as specified in Table 8. 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 §63.7525(a).</td>
</tr>
<tr>
<td>9. SO₂ CEMS</td>
<td>For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO₂ CEMS, maintain the 30-day rolling average SO₂ emission rate at or below the highest hourly average SO₂ concentration measured during the HCl performance test, as specified in Table 8.</td>
</tr>
</tbody>
</table>

*A wet acid gas scrubber is a control device that removes acid gases by contacting the combustion gas with an alkaline slurry or solution. Alkaline reagents include, but not limited to, lime, limestone and sodium.

[80 FR 72874, Nov. 20, 2015]

**Table 5 to Subpart DDDDD of Part 63—Performance Testing Requirements**

As stated in §63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

C-88
<table>
<thead>
<tr>
<th>To conduct a performance test for the following pollutant . . .</th>
<th>You must. . .</th>
<th>Using, as appropriate . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Filterable PM</td>
<td>a. Select sampling ports location and the number of traverse points</td>
<td>Method 1 at 40 CFR part 60, appendix A-1 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>c. Determine oxygen or carbon dioxide concentration of the stack gas</td>
<td>Method 3A or 3B at 40 CFR part 60, appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.</td>
</tr>
<tr>
<td></td>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 at 40 CFR part 60, appendix A-3 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>e. Measure the PM emission concentration</td>
<td>Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>f. Convert emissions concentration to lb per MMBtu emission rates</td>
<td>Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.</td>
</tr>
<tr>
<td>2. TSM</td>
<td>a. Select sampling ports location and the number of traverse points</td>
<td>Method 1 at 40 CFR part 60, appendix A-1 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>c. Determine oxygen or carbon dioxide concentration of the stack gas</td>
<td>Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.</td>
</tr>
<tr>
<td></td>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 at 40 CFR part 60, appendix A-3 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>e. Measure the TSM emission concentration</td>
<td>Method 29 at 40 CFR part 60, appendix A-8 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>f. Convert emissions concentration to lb per MMBtu emission rates</td>
<td>Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.</td>
</tr>
<tr>
<td>3. Hydrogen chloride</td>
<td>a. Select sampling ports location and the number of traverse points</td>
<td>Method 1 at 40 CFR part 60, appendix A-1 of this chapter.</td>
</tr>
<tr>
<td></td>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>---</td>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td>c. Determine oxygen or carbon dioxide concentration of the stack gas</td>
<td>Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981.a</td>
<td></td>
</tr>
<tr>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 at 40 CFR part 60, appendix A-3 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>e. Measure the hydrogen chloride emission concentration</td>
<td>Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>f. Convert emissions concentration to lb per MMBtu emission rates</td>
<td>Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.</td>
<td></td>
</tr>
</tbody>
</table>

4. Mercury

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>a. Select sampling ports location and the number of traverse points</td>
<td>Method 1 at 40 CFR part 60, appendix A-1 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>b. Determine velocity and volumetric flow-rate of the stack gas</td>
<td>Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>c. Determine oxygen or carbon dioxide concentration of the stack gas</td>
<td>Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.a</td>
<td></td>
</tr>
<tr>
<td>d. Measure the moisture content of the stack gas</td>
<td>Method 4 at 40 CFR part 60, appendix A-3 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>e. Measure the mercury emission concentration</td>
<td>Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784.a</td>
<td></td>
</tr>
<tr>
<td>f. Convert emissions concentration to lb per MMBtu emission rates</td>
<td>Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.</td>
<td></td>
</tr>
</tbody>
</table>

5. CO

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>a. Select the sampling ports location and the number of traverse points</td>
<td>Method 1 at 40 CFR part 60, appendix A-1 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>b. Determine oxygen concentration of the stack gas</td>
<td>Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981.a</td>
<td></td>
</tr>
<tr>
<td>c. Measure the moisture content of the stack gas</td>
<td>Method 4 at 40 CFR part 60, appendix A-3 of this chapter.</td>
<td></td>
</tr>
<tr>
<td>d. Measure the CO emission concentration</td>
<td>Method 10 at 40 CFR part 60, appendix A-4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.</td>
<td></td>
</tr>
</tbody>
</table>

---

*aIncorporated by reference, see §63.14.
Table 6 to Subpart DDDDD of Part 63—Fuel Analysis Requirements

As stated in §63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in §63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

<table>
<thead>
<tr>
<th>To conduct a fuel analysis for the following pollutant . . .</th>
<th>You must . . .</th>
<th>Using . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Mercury</td>
<td>a. Collect fuel samples</td>
<td>Procedure in §63.7521(c) or ASTM D5192a, ASTM D7430a, ASTM D6883a, ASTM D2234/D2234Ma (for coal) or ASTM D6323a (for solid), or ASTM D4177a (for liquid), or ASTM D4057a (for liquid), or equivalent.</td>
</tr>
<tr>
<td></td>
<td>b. Composite fuel samples</td>
<td>Procedure in §63.7521(d) or equivalent.</td>
</tr>
<tr>
<td></td>
<td>c. Prepare composited fuel samples</td>
<td>EPA SW-846-3050Ba (for solid samples), ASTM D2013/D2013Ma (for coal), ASTM D5198a (for biomass), or EPA 3050a (for solid fuel), or EPA 821-R-01-013a (for liquid or solid), or equivalent.</td>
</tr>
<tr>
<td></td>
<td>d. Determine heat content of the fuel type</td>
<td>ASTM D5865a (for coal) or ASTM E711a (for biomass), or ASTM D5864a for liquids and other solids, or ASTM D240a or equivalent.</td>
</tr>
<tr>
<td></td>
<td>e. Determine moisture content of the fuel type</td>
<td>ASTM D3173a, ASTM E871a, ASTM D240, or ASTM D95a (for liquid fuels), or ASTM D4006a (for liquid fuels), or equivalent.</td>
</tr>
<tr>
<td></td>
<td>f. Measure mercury concentration in fuel sample</td>
<td>ASTM D6722a (for coal), EPA SW-846-7471Ba or EPA 1631 or EPA 1631E (for solid samples), or EPA SW-846-7470Aa (for liquid samples), or EPA 821-R-01-013 (for liquid or solid), or equivalent.</td>
</tr>
<tr>
<td></td>
<td>g. Convert concentration into units of pounds of mercury per MMBtu of heat content</td>
<td>For fuel mixtures use Equation 8 in §63.7530.</td>
</tr>
</tbody>
</table>

| 2. HCl | a. Collect fuel samples | Procedure in §63.7521(c) or ASTM D5192a, ASTM D7430a, ASTM D6883a, ASTM D2234/D2234Ma (for coal) or ASTM D6323a (for coal or biomass), ASTM D4177a (for liquid fuels) or ASTM D4057a (for liquid fuels), or equivalent. |
| | b. Composite fuel samples | Procedure in §63.7521(d) or equivalent. |
| | c. Prepare composited fuel samples | EPA SW-846-3050Ba (for solid samples), ASTM D2013/D2013Ma (for coal), or ASTM D5198a (for biomass), or EPA 3050a or equivalent. |
| | d. Determine heat content of the | ASTM D5865a (for coal) or ASTM E711a (for biomass), or ASTM D5864a for liquids and other solids, or ASTM D240a or equivalent. |
| fuel type | biomass), ASTM D5864, ASTM D240\(^a\) or equivalent. |
|-----------------------------------------------|
| e. Determine moisture content of the fuel type | ASTM D3173\(^a\) or ASTM E871\(^a\), or D5864\(^a\), or ASTM D240\(^a\), or ASTM D95\(^a\) (for liquid fuels), or ASTM D4006\(^a\) (for liquid fuels), or equivalent. |
| f. Measure chlorine concentration in fuel sample | EPA SW-846-9250\(^a\), ASTM D6721\(^a\), ASTM D4208\(^a\) (for coal), or EPA SW-846-5050\(^a\) or ASTM E776\(^a\) (for solid fuel), or EPA SW-846-9056\(^a\) or SW-846-9076\(^a\) (for solids or liquids) or equivalent. |
| g. Convert concentrations into units of pounds of HCl per MMBtu of heat content | For fuel mixtures use Equation 7 in §63.7530 and convert from chlorine to HCl by multiplying by 1.028. |

3. Mercury Fuel Specification for other gas 1 fuels
a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter, or Method 30B (M30B) at 40 CFR part 60, appendix A-8 of this chapter or ASTM D5954\(^a\), ASTM D6350\(^a\), ISO 6978-1:2003(E), or ISO 6978-2:2003(E), or EPA-1631\(^a\) or equivalent.  
b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784\(^a\) or equivalent.  

c. Prepare composited fuel samples Procedure in §63.7521(c) or ASTM D5192\(^a\), or ASTM D7430\(^a\), or ASTM D6883\(^a\), or ASTM D2234/D2234M\(^a\) (for coal) or ASTM D6323\(^a\) (for coal or biomass), or ASTM D4177\(^a\) (for liquid fuels) or ASTM D4057\(^a\) (for liquid fuels), or equivalent.  
da. Collect fuel samples Procedure in §63.7521(c) or ASTM D5192\(^a\), or ASTM D7430\(^a\), or ASTM D6883\(^a\), or ASTM D2234/D2234M\(^a\) (for coal) or ASTM D6323\(^a\) (for coal or biomass), or ASTM D4177\(^a\) (for liquid fuels) or ASTM D4057\(^a\) (for liquid fuels), or equivalent.  
b. Composite fuel samples Procedure in §63.7521(d) or equivalent.  
c. Measure TSM concentration in fuel sample ASTM D5865\(^a\) (for coal) or ASTM E711\(^a\) (for biomass), or ASTM D5864\(^a\) for liquids and other solids, or ASTM D240\(^a\) or equivalent.  
d. Convert concentrations into units of pounds of TSM per MMBtu of heat content For fuel mixtures use Equation 9 in §63.7530.
As stated in §63.7520, you must comply with the following requirements for establishing operating limits:

**Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits**

<table>
<thead>
<tr>
<th>If you have an applicable emission limit for . . .</th>
<th>And your operating limits are based on . . .</th>
<th>You must . . .</th>
<th>Using . . .</th>
<th>According to the following requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. PM, TSM, or mercury</td>
<td>a. Wet scrubber operating parameters</td>
<td>i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to §63.7530(b)</td>
<td>(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM, TSM, or mercury performance test</td>
<td>(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests. (b) Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.</td>
</tr>
<tr>
<td></td>
<td>b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers)</td>
<td>i. Establish a site-specific minimum total secondary electric power input according to §63.7530(b)</td>
<td>(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test</td>
<td>(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests. (b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.</td>
</tr>
<tr>
<td></td>
<td>c. Opacity</td>
<td>i. Establish a site-specific maximum opacity level</td>
<td>(1) Data from the opacity monitoring system during the PM performance test</td>
<td>(a) You must collect opacity readings every 15 minutes during the entire period of the performance tests. (b) Determine the average hourly opacity reading for each performance test run by computing the hourly . . .</td>
</tr>
</tbody>
</table>

*Incorporated by reference, see §63.14.*
<table>
<thead>
<tr>
<th>2. HCl</th>
<th>a. Wet scrubber operating parameters</th>
<th>i. Establish site-specific minimum effluent pH and flow rate operating limits according to §63.7530(b)</th>
<th>(1) Data from the pH and liquid flow-rate monitors and the HCl performance test</th>
<th>(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the highest hourly average opacity reading measured during the test run demonstrating compliance with the PM (or TSM) emission limitation.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>b. Dry scrubber operating parameters</td>
<td>i. Establish a site-specific minimum sorbent injection rate operating limit according to §63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent</td>
<td>(1) Data from the sorbent injection rate monitors and HCl or mercury performance test</td>
<td>(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction, as defined in §63.7575, to determine the required injection rate.</td>
</tr>
<tr>
<td></td>
<td>c. Alternative Maximum SO₂ emission rate</td>
<td>i. Establish a site-specific maximum SO₂ emission rate operating limit according to §63.7530(b)</td>
<td>(1) Data from SO₂ CEMS and the HCl performance test</td>
<td>(a) You must collect the SO₂ emissions data according to §63.7525(m) during the most recent HCl performance tests. (b) The maximum SO₂ emission rate is equal to the highest hourly average SO₂ emission rate measured during the most recent HCl</td>
</tr>
</tbody>
</table>
3. Mercury
   a. Activated carbon injection
      i. Establish a site-specific minimum activated carbon injection rate operating limit according to §63.7530(b)
      (1) Data from the activated carbon rate monitors and mercury performance test
      (a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests.
      (b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
      (c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction, as defined in §63.7575, to determine the required injection rate.

4. Carbon monoxide for which compliance is demonstrated by a performance test
   a. Oxygen
      i. Establish a unit-specific limit for minimum oxygen level according to §63.7530(b)
      (1) Data from the oxygen analyzer system specified in §63.7525(a)
      (a) You must collect oxygen data every 15 minutes during the entire period of the performance tests.
      (b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test.
      (c) Determine the lowest hourly average established during the performance test as your minimum operating limit.

5. Any pollutant for which compliance is demonstrated by a performance test
   a. Boiler or process heater operating load
      i. Establish a unit specific limit for maximum operating load according to §63.7520(c)
      (1) Data from the operating load monitors or from steam generation monitors
      (a) You must collect operating load 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 highest hourly average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

*Operating limits must be confirmed or reestablished during performance tests.

*If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests. For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

[80 FR 72827, Nov. 20, 2015]

**Table 8 to Subpart DDDDD of Part 63—Demonstrating Continuous Compliance**

As stated in §63.7540, you must show continuous compliance with the emission limitations for each boiler or process heater according to the following:

<table>
<thead>
<tr>
<th>If you must meet the following operating limits or work practice standards . . .</th>
<th>You must demonstrate continuous compliance by . . .</th>
</tr>
</thead>
</table>
| 1. Opacity | a. Collecting the opacity monitoring system data according to §63.7525(c) and §63.7535; and  
  b. Reducing the opacity monitoring data to 6-minute averages; and  
  c. Maintaining daily block average opacity to less than or equal to 10 percent or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation. |
| 2. PM CPMS | a. Collecting the PM CPMS output data according to §63.7525;  
  b. Reducing the data to 30-day rolling averages; and  
  c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to §63.7530(b)(4). |
| 3. Fabric Filter Bag Leak Detection Operation | Installing and operating a bag leak detection system according to §63.7525 and operating the fabric filter such that the requirements in §63.7540(a)(7) are met. |
| 4. Wet Scrubber Pressure Drop and Liquid Flow-rate | a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§63.7525 and 63.7535; 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 operating limits established during the performance test according to §63.7530(b). |
5. Wet Scrubber pH
   a. Collecting the pH monitoring system data according to §§63.7525 and 63.7535; and
   b. Reducing the data to 30-day rolling averages; and
   c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to §63.7530(b).

6. Dry Scrubber Sorbent or Carbon Injection Rate
   a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§63.7525 and 63.7535; and
   b. Reducing the data to 30-day rolling averages; and
   c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in §63.7575.

7. Electrostatic Precipitator Total Secondary Electric Power Input
   a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§63.7525 and 63.7535; and
   b. Reducing the data to 30-day rolling averages; and
   c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to §63.7530(b).

8. Emission limits using fuel analysis
   a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and
   b. Reduce the data to 12-month rolling averages; and
   c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 to this subpart.
   d. Calculate the HCI, mercury, and/or TSM emission rate from the boiler or process heater in units of lb/MMBtu using Equation 15 and Equations 17, 18, and/or 19 in §63.7530.

9. Oxygen content
   a. Continuously monitor the oxygen content using an oxygen analyzer system according to §63.7525(a). 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 §63.7525(a)(7).
   b. Reducing the data to 30-day rolling averages; and
   c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the CO performance test.

10. Boiler or process heater operating load
    a. Collecting operating load data or steam generation data every 15 minutes.
    b. Reducing the data to 30-day rolling averages; and
    c. Maintaining the 30-day rolling average operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test according to §63.7520(c).

11. SO₂ emissions using SO₂ CEMS
    a. Collecting the SO₂ CEMS output data according to §63.7525;
    b. Reducing the data to 30-day rolling averages; and
c. Maintaining the 30-day rolling average SO₂ CEMS emission rate to a level at or below the highest hourly SO₂ rate measured during the HCl performance test according to §63.7530.


Table 9 to Subpart DDDDD of Part 63—Reporting Requirements

As stated in §63.7550, you must comply with the following requirements for reports:

<table>
<thead>
<tr>
<th>You must submit a(n)</th>
<th>The report must contain . . .</th>
<th>You must submit the report . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Compliance report</td>
<td>a. Information required in §63.7550(c)(1) through (5); and</td>
<td>Semiannually, annually, biennially, or every 5 years according to the requirements in §63.7550(b).</td>
</tr>
<tr>
<td></td>
<td>b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards for periods of startup and shutdown in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and</td>
<td></td>
</tr>
<tr>
<td></td>
<td>c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard for periods of startup and shutdown, during the reporting period, the report must contain the information in §63.7550(d); and</td>
<td></td>
</tr>
<tr>
<td></td>
<td>d. If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), or otherwise not operating, the report must contain the information in §63.7550(e)</td>
<td></td>
</tr>
</tbody>
</table>


Table 10 to Subpart DDDDD of Part 63—Applicability of General Provisions to Subpart DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:
<table>
<thead>
<tr>
<th>Citation</th>
<th>Subject</th>
<th>Applies to subpart DDDDD</th>
</tr>
</thead>
<tbody>
<tr>
<td>§63.1</td>
<td>Applicability</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.2</td>
<td>Definitions</td>
<td>Yes. Additional terms defined in §63.7575</td>
</tr>
<tr>
<td>§63.3</td>
<td>Units and Abbreviations</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.4</td>
<td>Prohibited Activities and Circumvention</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.5</td>
<td>Preconstruction Review and Notification Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(a), (b)(1)-(b)(5), (b)(7), (c)</td>
<td>Compliance with Standards and Maintenance Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(e)(1)(i)</td>
<td>General duty to minimize emissions.</td>
<td>No. See §63.7500(a)(3) for the general duty requirement.</td>
</tr>
<tr>
<td>§63.6(e)(1)(ii)</td>
<td>Requirement to correct malfunctions as soon as practicable.</td>
<td>No.</td>
</tr>
<tr>
<td>§63.6(e)(3)</td>
<td>Startup, shutdown, and malfunction plan requirements.</td>
<td>No.</td>
</tr>
<tr>
<td>§63.6(f)(1)</td>
<td>Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards.</td>
<td>No.</td>
</tr>
<tr>
<td>§63.6(f)(2) and (3)</td>
<td>Compliance with non-opacity emission standards.</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.6(g)</td>
<td>Use of alternative standards</td>
<td>Yes, except §63.7555(d)(13) specifies the procedure for application and approval of an alternative timeframe with the PM controls requirement in the startup work practice (2).</td>
</tr>
<tr>
<td>§63.6(h)(1)</td>
<td>Startup, shutdown, and malfunction exemptions to opacity standards.</td>
<td>No. See §63.7500(a).</td>
</tr>
<tr>
<td>§63.6(h)(2) to (h)(9)</td>
<td>Determining compliance with opacity emission standards</td>
<td>No. Subpart DDDDD specifies opacity as an operating limit not an emission standard.</td>
</tr>
<tr>
<td>§63.6(i)</td>
<td>Extension of compliance</td>
<td>Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with</td>
</tr>
<tr>
<td>Section</td>
<td>Description</td>
<td>Compliance</td>
</tr>
<tr>
<td>---------</td>
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</tr>
<tr>
<td>§63.6(j)</td>
<td>Presidential exemption.</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.7(a), (b), (c), and (d)</td>
<td>Performance Testing Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.7(e)(1)</td>
<td>Conditions for conducting performance tests</td>
<td>No. Subpart DDDDD specifies conditions for conducting performance tests at §63.7520(a) to (c).</td>
</tr>
<tr>
<td>§63.7(e)(2)-(e)(9), (f), (g), and (h)</td>
<td>Performance Testing Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(a) and (b)</td>
<td>Applicability and Conduct of Monitoring</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(c)(1)</td>
<td>Operation and maintenance of CMS</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(c)(1)(i)</td>
<td>General duty to minimize emissions and CMS operation</td>
<td>No. See §63.7500(a)(3).</td>
</tr>
<tr>
<td>§63.8(c)(1)(ii)</td>
<td>Operation and maintenance of CMS</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(c)(1)(iii)</td>
<td>Startup, shutdown, and malfunction plans for CMS</td>
<td>No.</td>
</tr>
<tr>
<td>§63.8(c)(2) to (c)(9)</td>
<td>Operation and maintenance of CMS</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(d)(1) and (2)</td>
<td>Monitoring Requirements, Quality Control Program</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(d)(3)</td>
<td>Written procedures for CMS</td>
<td>Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.</td>
</tr>
<tr>
<td>§63.8(e)</td>
<td>Performance evaluation of a CMS</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(f)</td>
<td>Use of an alternative monitoring method.</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.8(g)</td>
<td>Reduction of monitoring data</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.9</td>
<td>Notification Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(a), (b)(1)</td>
<td>Recordkeeping and Reporting Requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(2)(i)</td>
<td>Recordkeeping of occurrence and duration of startups or shutdowns</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(2)(ii)</td>
<td>Recordkeeping of</td>
<td>No. See §63.7555(d)(7) for recordkeeping</td>
</tr>
<tr>
<td>Section</td>
<td>Requirement</td>
<td>Applicability</td>
</tr>
<tr>
<td>---------</td>
<td>----------------------------------------------------------------------------</td>
<td>---------------</td>
</tr>
<tr>
<td>§63.10(b)(2)(iii)</td>
<td>Maintenance records</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(2)(iv) and (v)</td>
<td>Actions taken to minimize emissions during startup, shutdown, or malfunction</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(b)(2)(vi)</td>
<td>Recordkeeping for CMS malfunctions</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(2)(vii) to (xiv)</td>
<td>Other CMS requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(b)(3)</td>
<td>Recordkeeping requirements for applicability determinations</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(c)(1) to (9)</td>
<td>Recordkeeping for sources with CMS</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(c)(10) and (11)</td>
<td>Recording nature and cause of malfunctions, and corrective actions</td>
<td>No. See §63.7555(d)(7) for recordkeeping of occurrence and duration and §63.7555(d)(8) for actions taken during malfunctions.</td>
</tr>
<tr>
<td>§63.10(c)(12) and (13)</td>
<td>Recordkeeping for sources with CMS</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(c)(15)</td>
<td>Use of startup, shutdown, and malfunction plan</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(d)(1) and (2)</td>
<td>General reporting requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(d)(3)</td>
<td>Reporting opacity or visible emission observation results</td>
<td>No.</td>
</tr>
<tr>
<td>§63.10(d)(4)</td>
<td>Progress reports under an extension of compliance</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(d)(5)</td>
<td>Startup, shutdown, and malfunction reports</td>
<td>No. See §63.7550(c)(11) for malfunction reporting requirements.</td>
</tr>
<tr>
<td>§63.10(e)</td>
<td>Additional reporting requirements for sources with CMS</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.10(f)</td>
<td>Waiver of recordkeeping or reporting requirements</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.11</td>
<td>Control Device Requirements</td>
<td>No.</td>
</tr>
<tr>
<td>§63.12</td>
<td>State Authority and Delegation</td>
<td>Yes.</td>
</tr>
<tr>
<td>§63.13-63.16</td>
<td>Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions</td>
<td>Yes.</td>
</tr>
<tr>
<td>§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), (b)(4), 63.10(c)(2)-(4), (c)(9).</td>
<td>Reserved</td>
<td>No.</td>
</tr>
</tbody>
</table>


Table 11 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011

<table>
<thead>
<tr>
<th>If your boiler or process heater is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .</th>
<th>Using this specified sampling volume or test run duration . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Units in all subcategories designed to burn solid fuel</td>
<td>a. HCl</td>
<td>0.022 lb per MMBtu of heat input</td>
<td>For M26, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.</td>
</tr>
<tr>
<td>2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis</td>
<td>a. Mercury</td>
<td>8.0E-07 lb per MMBtu of heat input</td>
<td>For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 collect a minimum of 4 dscm.</td>
</tr>
<tr>
<td>3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis</td>
<td>a. Mercury</td>
<td>2.0E-06 lb per MMBtu of heat input</td>
<td>For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 collect a minimum of 4 dscm.</td>
</tr>
<tr>
<td>4. Units design to burn coal/solid fossil fuel</td>
<td>a. Filterable PM (or TSM)</td>
<td>1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td>5. Pulverized coal boilers designed to burn coal/solid fossil fuel</td>
<td>a. Carbon monoxide (CO) (or CEMS)</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td><strong>6. Stokers designed to burn coal/solid fossil fuel</strong></td>
<td><strong>a. CO (or CEMS)</strong></td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>---</td>
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<td>---</td>
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</tr>
<tr>
<td><strong>7. Fluidized bed units designed to burn coal/solid fossil fuel</strong></td>
<td><strong>a. CO (or CEMS)</strong></td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td><strong>8. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel</strong></td>
<td><strong>a. CO (or CEMS)</strong></td>
<td>140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td><strong>9. Stokers/sloped grate/others designed to burn wet biomass fuel</strong></td>
<td><strong>a. CO (or CEMS)</strong></td>
<td>620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td><strong>b. Filterable PM (or TSM)</strong></td>
<td>3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
<td></td>
</tr>
<tr>
<td><strong>10. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel</strong></td>
<td><strong>a. CO</strong></td>
<td>560 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td><strong>b. Filterable PM (or TSM)</strong></td>
<td>3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
<td></td>
</tr>
<tr>
<td><strong>11. Fluidized bed units designed to burn biomass/bio-based solids</strong></td>
<td><strong>a. CO (or CEMS)</strong></td>
<td>230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td><strong>b. Filterable PM (or TSM)</strong></td>
<td>9.8E-03 lb per MMBtu of heat input; or (3.8E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>PM (or TSM)</td>
<td>heat input; or (8.3E-05 lb per MMBtu of heat input)</td>
<td>dscm per run.</td>
</tr>
<tr>
<td>---</td>
<td>-------------</td>
<td>-----------------------------------------------------</td>
<td>----------------</td>
</tr>
<tr>
<td>12. Suspension burners designed to burn biomass/bio-based solids</td>
<td>PM (or TSM)</td>
<td>2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td>13. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids</td>
<td>PM (or TSM)</td>
<td>1,010 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>8.0E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td>14. Fuel cell units designed to burn biomass/bio-based solids</td>
<td>PM (or TSM)</td>
<td>910 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td>15. Hybrid suspension grate boiler designed to burn biomass/bio-based solids</td>
<td>PM (or TSM)</td>
<td>1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td>16. Units designed to burn liquid fuel</td>
<td>PM (or TSM)</td>
<td>4.4E-04 lb per MMBtu of heat input</td>
<td>For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.</td>
</tr>
<tr>
<td>Table Row</td>
<td>Fuel Type</td>
<td>Parameter</td>
<td>Unit of Measurement</td>
</tr>
<tr>
<td>-----------</td>
<td>-----------</td>
<td>-----------</td>
<td>---------------------</td>
</tr>
<tr>
<td>17. Units designed to burn heavy liquid fuel</td>
<td>a. CO</td>
<td>CO</td>
<td>ppm by volume</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>CO</td>
<td>lb per MMBtu of heat input</td>
</tr>
<tr>
<td>18. Units designed to burn light liquid fuel</td>
<td>a. CO</td>
<td>CO</td>
<td>ppm by volume</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>CO</td>
<td>lb per MMBtu of heat input</td>
</tr>
<tr>
<td>19. Units designed to burn liquid fuel that are non-continental units</td>
<td>a. CO</td>
<td>CO</td>
<td>ppm by volume</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>CO</td>
<td>lb per MMBtu of heat input</td>
</tr>
<tr>
<td>20. Units designed to burn gas 2 (other) gases</td>
<td>a. CO</td>
<td>CO</td>
<td>ppm by volume</td>
</tr>
<tr>
<td></td>
<td>b. HCl</td>
<td>HCl</td>
<td>lb per MMBtu of heat input</td>
</tr>
<tr>
<td></td>
<td>c. Mercury</td>
<td>Mercury</td>
<td>lb per MMBtu of heat input</td>
</tr>
<tr>
<td></td>
<td>d. Filterable PM (or TSM)</td>
<td>PM (or TSM)</td>
<td>lb per MMBtu of heat input</td>
</tr>
</tbody>
</table>
If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provision of §63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

Incorporated by reference, see §63.14.

An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO₂ correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO₂ being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[80 FR 72831, Nov. 20, 2015]

Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After May 20, 2011, and Before December 23, 2011

<table>
<thead>
<tr>
<th>If your boiler or process heater is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .</th>
<th>Using this specified sampling volume or test run duration . . .</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Units in all subcategories designed to burn solid fuel</td>
<td>a. HCl</td>
<td>0.022 lb per MMBtu of heat input</td>
<td>For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.</td>
</tr>
<tr>
<td></td>
<td>b. Mercury</td>
<td>3.5E-06₇ lb per MMBtu of heat input</td>
<td>For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784ᵇ collect a minimum of 3 dscm.</td>
</tr>
<tr>
<td>2. Units design to burn coal/solid fossil fuel</td>
<td>a. Filterable PM (or TSM)</td>
<td>1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td>3. Pulverized coal boilers designed to burn coal/solid fossil fuel</td>
<td>a. Carbon monoxide (CO) (or CEMS)</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, ³ 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>4. Stokers designed to burn coal/solid fossil fuel</td>
<td>a. CO (or CEMS)</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, ⁴ 10-day rolling</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
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<td></td>
<td></td>
</tr>
<tr>
<td>5. Fluidized bed units designed to burn coal/solid fossil fuel</td>
<td>a. CO (or CEMS)</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>1 hr minimum sampling time.</td>
<td></td>
</tr>
<tr>
<td>6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel</td>
<td>a. CO (or CEMS)</td>
<td>140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>1 hr minimum sampling time.</td>
<td></td>
</tr>
<tr>
<td>7. Stokers/sloped grate/others designed to burn wet biomass fuel</td>
<td>a. CO (or CEMS)</td>
<td>620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Collect a minimum of 2 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel</td>
<td>a. CO</td>
<td>460 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>3.0E-02 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Collect a minimum of 2 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>9. Fluidized bed units designed to burn biomass/bio-based solids</td>
<td>a. CO (or CEMS)</td>
<td>260 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>9.8E-03 lb per MMBtu of heat input; or (8.3E-05 lb per MMBtu of heat input)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Collect a minimum of 3 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>10. Suspension burners designed to burn biomass/bio-based solids</td>
<td>a. CO (or CEMS)</td>
<td>2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>3.0E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Collect a minimum of 2 dscm per run.</td>
<td></td>
</tr>
<tr>
<td>Description</td>
<td>Measurement Parameters</td>
<td>Additional Requirements</td>
<td></td>
</tr>
<tr>
<td>----------------------------------------------------------------------------</td>
<td>----------------------------------------------------------------------------------------</td>
<td>-------------------------</td>
<td></td>
</tr>
<tr>
<td><strong>11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids</strong></td>
<td>a. CO (or CEMS) 470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM) 3.2E-03 lb per MMBtu of heat input; or (3.9E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
<td></td>
</tr>
<tr>
<td><strong>12. Fuel cell units designed to burn biomass/bio-based solids</strong></td>
<td>a. CO 910 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average 2.0E-02 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)</td>
<td>1 hr minimum sampling time. Collect a minimum of 2 dscm per run.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM) 2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
<td></td>
</tr>
<tr>
<td><strong>13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids</strong></td>
<td>a. CO (or CEMS) 1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM) 2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
<td></td>
</tr>
<tr>
<td><strong>14. Units designed to burn liquid fuel</strong></td>
<td>a. HCl 4.4E-04 lb per MMBtu of heat input</td>
<td>For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Mercury 4.8E-07 lb per MMBtu of heat input</td>
<td>For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784, collect a minimum of 4 dscm.</td>
<td></td>
</tr>
<tr>
<td><strong>15. Units designed to burn heavy liquid fuel</strong></td>
<td>a. CO 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average</td>
<td>1 hr minimum sampling time.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM) 1.3E-02 lb per MMBtu of heat input; or (7.5E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
<td></td>
</tr>
<tr>
<td><strong>16. Units designed to burn light liquid fuel</strong></td>
<td>a. CO 130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average</td>
<td>1 hr minimum sampling time.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM) 1.3E-03 lb per MMBtu of heat input; or (2.9E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
<td></td>
</tr>
</tbody>
</table>
17. Units designed to burn liquid fuel that are non-continental units

<table>
<thead>
<tr>
<th>a. CO</th>
<th>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test</th>
<th>1 hr minimum sampling time.</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. Filterable PM (or TSM)</td>
<td>2.3E-02 lb per MMBtu of heat input; or (8.6E-04 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 4 dscm per run.</td>
</tr>
</tbody>
</table>

18. Units designed to burn gas 2 (other) gases

<table>
<thead>
<tr>
<th>a. CO</th>
<th>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average</th>
<th>1 hr minimum sampling time.</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. HCl</td>
<td>1.7E-03 lb per MMBtu of heat input</td>
<td>For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.</td>
</tr>
<tr>
<td>c. Mercury</td>
<td>7.9E-06 lb per MMBtu of heat input</td>
<td>For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784collect a minimum of 3 dscm.</td>
</tr>
<tr>
<td>d. Filterable PM (or TSM)</td>
<td>6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
</tbody>
</table>

If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to §63.7515 if all of the other provisions of §63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

Incorporated by reference, see §63.14.

An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

[80 FR 72834, Nov. 20, 2015]

Table 13 to Subpart DDDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After December 23, 2011, and Before April 1, 2013

<table>
<thead>
<tr>
<th>If your boiler or process heater is in this subcategory . . .</th>
<th>For the following pollutants . . .</th>
<th>The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .</th>
<th>Using this specified sampling volume or test run duration . . .</th>
</tr>
</thead>
</table>

C-109
<p>| | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Units in all subcategories designed to burn solid fuel</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>a. HCl</td>
<td>0.022 lb per MMBtu of heat input</td>
<td>For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.</td>
</tr>
<tr>
<td></td>
<td>b. Mercury</td>
<td>8.6E-07 lb per MMBtu of heat input</td>
<td>For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784b collect a minimum of 4 dscm.</td>
</tr>
<tr>
<td>2. Pulverized coal boilers designed to burn coal/solid fossil fuel</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>a. Carbon monoxide (CO) (or CEMS)</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>1.1E-03 lb per MMBtu of heat input; or (2.8E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td>3. Stokers designed to burn coal/solid fossil fuel</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>a. CO (or CEMS)</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>2.8E-02 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td>4. Fluidized bed units designed to burn coal/solid fossil fuel</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>a. CO (or CEMS)</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td>5. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>a. CO (or CEMS)</td>
<td>140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>b. Filterable PM (or TSM)</td>
<td>1.1E-03 lb per MMBtu of heat input; or (2.3E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td>6. Stokers/sloped grate/others designed to burn wet biomass fuel</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>a. CO (or CEMS)</td>
<td>620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td><strong>7. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel</strong></td>
<td><strong>b. Filterable PM (or TSM)</strong></td>
<td>3.0E-02 lb per MMBtu of heat input; or (2.6E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
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<tr>
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</tr>
<tr>
<td><strong>8. Fluidized bed units designed to burn biomass/bio-based solids</strong></td>
<td><strong>a. CO</strong></td>
<td>460 ppm by volume on a dry basis corrected to 3 percent oxygen</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td><strong>b. Filterable PM (or TSM)</strong></td>
<td>3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td><strong>9. Suspension burners designed to burn biomass/bio-based solids</strong></td>
<td><strong>a. CO (or CEMS)</strong></td>
<td>230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td><strong>b. Filterable PM (or TSM)</strong></td>
<td>9.8E-03 lb per MMBtu of heat input; or (8.3E-05 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td><strong>10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids</strong></td>
<td><strong>a. CO (or CEMS)</strong></td>
<td>2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td><strong>b. Filterable PM (or TSM)</strong></td>
<td>5.1E-02 lb per MMBtu of heat input; or (6.5E-03 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td><strong>11. Fuel cell units designed to burn biomass/bio-based solids</strong></td>
<td><strong>a. CO</strong></td>
<td>810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td><strong>b. Filterable PM (or TSM)</strong></td>
<td>3.6E-02 lb per MMBtu of heat input; or (3.9E-03 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td><strong>12. Hybrid suspension grate boiler designed to burn biomass/bio-based solids</strong></td>
<td><strong>a. CO (or CEMS)</strong></td>
<td>910 ppm by volume on a dry basis corrected to 3 percent oxygen</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td><strong>b. Filterable PM (or TSM)</strong></td>
<td>2.0E-02 lb per MMBtu of heat input; or (2.9E-03 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 2 dscm per run.</td>
</tr>
<tr>
<td>Units designed to burn liquid fuel</td>
<td>CO (or CEMS)</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen, (^c) 10-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>----------------------------------</td>
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<td>---------------------------------------------------------------------------------------------------------------------------------</td>
<td>-----------------------------</td>
</tr>
<tr>
<td>Units designed to burn heavy liquid fuel</td>
<td>CO (or CEMS)</td>
<td>130a ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen, (^c) 10-day rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>Units designed to burn liquid fuel that are non-continental units</td>
<td>CO</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test; or (91 ppm by volume on a dry basis corrected to 3 percent oxygen, (^c) 3-hour rolling average)</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td>Units designed to burn gas 2 (other) gases</td>
<td>CO</td>
<td>130 ppm by volume on a dry basis corrected to 3 percent oxygen</td>
<td>1 hr minimum sampling time.</td>
</tr>
<tr>
<td></td>
<td>HCl</td>
<td>1.2E-03 lb per MMBtu of heat input</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>Mercury</td>
<td>4.9E-07 lb per MMBtu of heat input</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>Filterable PM (or TSM)</td>
<td>2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>HCl</td>
<td>1.2E-03 lb per MMBtu of heat input</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>Mercury</td>
<td>4.9E-07 lb per MMBtu of heat input</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>Filterable PM (or TSM)</td>
<td>2.6E-02 lb per MMBtu of heat input; or (4.4E-04 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>HCl</td>
<td>1.2E-03 lb per MMBtu of heat input</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
<tr>
<td></td>
<td>Mercury</td>
<td>4.9E-07 lb per MBBtu of heat input</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
</tbody>
</table>

\(^c\) 30-day rolling average
<table>
<thead>
<tr>
<th>Method</th>
<th>Unit</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>d. Filterable PM (or TSM)</td>
<td>6.7E-03 lb per MMBtu of heat input; or (2.1E-04 lb per MMBtu of heat input)</td>
<td>Collect a minimum of 3 dscm per run.</td>
</tr>
</tbody>
</table>

If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit and you are not required to conduct testing for CEMS or CPMS monitor certification, you can skip testing according to §63.7515 if all of the other provision of §63.7515 are met. For all other pollutants that do not contain a footnote “a”, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

*Incorporated by reference, see §63.14.*

An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the carbon monoxide emissions limit be determined using carbon dioxide as a diluent correction in place of oxygen at 3%. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO₂ correction percentage for the fuel type burned in the unit, and must also take into account that the 3% oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO₂ being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

CERTIFICATE OF SERVICE

I, Cynthia Hook, hereby certify that a copy of this permit has been mailed by first class mail to PotlatchDeltic Manufacturing L.L.C. - Waldo Mill, P.O. Box 409, Waldo, AR, 71770, on this 29th day of November, 2018.

Cynthia Hook, ASIH, Office of Air Quality