



GENERAL AIR CONTAMINANT DISCHARGE PERMIT

Department of Environmental Quality
Operations Division
Air Operations Section
700 NE Multnomah Street, Suite 600
Portland, OR 97232
Telephone: (503) 229-5696

This permit is issued in accordance with the provisions of ORS 468A.040 and OAR 340-216-0060

ISSUED BY THE DEPARTMENT OF ENVIRONMENTAL QUALITY

Signed copy of permit on file at DEQ

October 4, 2017

Lydia Emer, Operations Division Administrator

Dated

Oil-fired boilers greater than 10 million Btu/hour heat input and natural gas, propane, or butane-fired boilers (with or without distillate oil backup) 30 million Btu/hour or more heat input. NAICS 221330. SIC 4961

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1.0 PERMIT ASSIGNMENT

1.1 Qualifications

The permittee must meet all of the following conditions in order to qualify for assignment to this General Air Contaminant Discharge Permit (ACDP):

- a. The permittee is operating oil, natural gas, propane, and/or butane-fired boiler(s) as listed on the cover of this permit, including supporting activities. This permit is not applicable to fuel burning equipment used to support other activities or sources required to have a permit under OAR 340-216-8010, Table 1.
- b. Notwithstanding condition 1.1a., this permit is applicable to space heating and process boilers described in the table below:

Size	Heat energy input capacity
Single boiler	Oil-fired boilers, greater than 10 MMBtu/hour
	Natural gas, propane, or butane-fired boilers, 30 MMBtu/hr or more
Aggregate on site	For oil-fired boilers greater than 10 MM BTU/hour but less than 250 MM BTU/hour
	For natural gas, propane, or butane-fired boilers equal to or greater than 30 MM BTU/hour but less than 250 MM BTU/hour.

- c. More than one boiler on site may be permitted with this General Permit provided that aggregate emissions from all boilers do not exceed the generic PSEL.
- d. A Simple or Standard ACDP is not required for the source.
- e. The source is not having ongoing, recurring or serious compliance problems.

1.2 Assignment

DEQ will assign qualifying permittees to this permit that have and maintain a good record of compliance with DEQ's Air Quality regulations and that DEQ determines would be appropriately regulated by a General ACDP. DEQ may rescind assignment if the permittee no longer meets the requirements of OAR 340-216-0025(2), 340-216-0060 and the conditions of this permit.

- 1.3 Permitted Activities** This permit allows the permittee to discharge air contaminants from processes and activities related to the air contaminant source(s) listed on the first page of this permit until this permit expires, is modified, revoked or rescinded. If there are other emissions activities occurring at the site besides those listed on the cover page of this permit, the permittee may be required to obtain an associated General ACDP Attachment or a Simple or Standard ACDP, if applicable.
- 1.4 Relation to local land use laws** This permit is not valid in Lane County, or at any location where the operation of the permittee's processes, activities, and insignificant activities would be in violation of any local land use or zoning laws. For operation in Lane County, contact Lane Regional Air Protection Agency for any necessary permits at (541) 736-1056. It is the permittee's sole responsibility to obtain local land use approvals as, or where, applicable before operating this facility at any location.

2.0 GENERAL EMISSION STANDARDS AND LIMITS

- 2.1 Visible Emissions** The permittee must comply with the following visible emission limits, as applicable:
- a. Visible emissions from sources installed, constructed or modified prior to June 1, 1970, and located outside a special control area, must not equal or exceed:
 - i. An average of 40 percent opacity through December 31, 2019; and
 - ii. An average of 20 percent opacity on and after January 1, 2020.
 - b. Visible emissions from sources installed, constructed or modified on or after June 1, 1970 must not equal or exceed an average of 20 percent opacity.
 - c. Visible emissions from any source located inside a special control area must not equal or exceed an average of 20 percent opacity.
 - d. The visible emissions limitation in this condition is based upon a six-minute block average of 24 consecutive observations recorded at 15-second intervals as specified in OAR 340-208-0110(2).
 - e. The visible emissions standard in this condition does not apply to fugitive emissions from the source.
 - f. As used in this condition, "special control area" means an area designated in OAR 340-204-0070:

- i. Benton, Clackamas, Columbia, Lane, Linn, Marion, Multnomah, Polk, Washington and Yamhill Counties;
- ii. Umpqua Basin and Rogue Basin - associated boundaries are defined in OAR 340-204-0010; and
- iii. Areas within incorporated cities having a population of 4,000 or more, and within three miles of the corporate limits of any such city.

2.2 Particulate Matter Emissions

The permittee must comply with the following particulate matter emission limits (i.e., total particulate matter, filterable plus condensable), as applicable. This condition does not apply to fugitive emission sources. Compliance with the emissions standards in this condition is determined using Oregon Method 5 or an alternative method approved by DEQ.

- a. Particulate matter emissions from any fuel burning equipment installed, constructed, or modified before June 1, 1970 must not exceed:
 - i. 0.10 grains per dry standard cubic foot corrected to 50% excess air provided that all representative compliance source test results (refer to Condition 2.2.d for the definition of 'representative compliance source test results') collected prior to April 16, 2015 demonstrate emissions no greater than 0.080 grains per dry standard cubic foot corrected to 50% excess air;
 - ii. If any representative compliance source test results collected prior to April 16, 2015 demonstrate emissions greater than 0.080 grains per dry standard cubic foot corrected to 50% excess air, or if there are no representative compliance source test results, then:
 - 0.24 grains per dry standard cubic foot corrected to 50% excess air until December 31, 2019; and
 - 0.15 grains per dry standard cubic foot corrected to 50% excess air on and after January 1, 2020.
 - iii. For equipment or a mode of operation (e.g., backup fuel) used less than 876 hours per calendar year:
 - 0.24 grains per dry standard cubic foot corrected to 50% excess air from April 16, 2015 through December 31, 2019; and

- 0.20 grains per dry standard cubic foot corrected to 50% excess air on and after January 1, 2020.
- b. Particulate matter emissions from any fuel burning equipment installed, constructed, or modified on or after June 1, 1970 but prior to April 16, 2015 must not exceed:
 - i. 0.10 grains per dry standard cubic foot corrected to 50% excess air provided that all representative compliance source test results collected prior to April 16, 2015 demonstrate emissions no greater than 0.080 grains per dry standard cubic foot corrected to 50% excess air; or
 - ii. 0.14 grains per dry standard cubic foot corrected to 50% excess air, if any representative compliance source test results collected prior to April 16, 2015 demonstrate emissions greater than 0.080 grains per dry standard cubic foot corrected to 50% excess air, or if there are no representative compliance source test results.
- c. Particulate matter emissions from any fuel burning equipment installed, constructed, or modified on or after April 16, 2015 must not exceed 0.10 grains per dry standard cubic foot corrected to 50% excess air.
- d. Representative compliance source test results are test data that was obtained between April 16, 2005 and April 15, 2015 inclusive, and are based on the current configuration of the plant and pollution control equipment.
- e. In Clackamas, Columbia, Multnomah, or Washington Counties, particulate matter emissions from fuel burning equipment must not exceed the emission rate shown in Figure 1 of OAR 340-208-0610 as a function of the maximum heat input when using all other fuels, except natural gas and LPG.

2.3 Fugitive Emissions

The permittee must comply with the following, as necessary:

- a. The permittee must not cause or permit any materials to be handled, transported, or stored; or a building, its appurtenances, or a road to be used, constructed, altered, repaired or demolished without taking reasonable precautions to prevent fugitive particulate matter from becoming airborne from all site operations from which it may be generated. Such reasonable precautions may include, but not be limited to:
 - i. Application of water or other suitable chemicals on unpaved roads, material stockpiles, and other surfaces which can create airborne dusts;

- ii. Full or partial enclosure of material stockpiles in cases where application of water or other suitable chemicals are not sufficient to prevent particulate matter from becoming airborne;
 - iii. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials;
 - iv. Adequate containment during sandblasting or other similar operations;
 - v. Covering, at all times when in motion, open bodied trucks transporting materials likely to become airborne;
 - vi. The prompt removal from paved streets of earth or other material that may become airborne.
 - b. For purposes of this condition, fugitive particulate emissions are visible emissions that leave the permittee's property for a period or periods totaling more than 18 seconds in a six minute period.
 - c. Fugitive emissions are determined by EPA Method 22 at the downwind property boundary.
- 2.4 **Particulate Matter Fallout** The permittee must not cause or permit the emission of any particulate matter larger than 250 microns in size at sufficient duration or quantity, as to create an observable deposition upon the real property of another person.
- 2.5 **Nuisance and Odors** The permittee must not cause or allow air contaminants from any source to cause a nuisance. Nuisance conditions will be verified by DEQ personnel.
- 2.6 **Fuels and Fuel Sulfur Content** The permittee must not use any fuel other than wood, natural gas, propane, butane, ASTM grade fuel oils, or on-specification used oil.
 - a. Fuel oils must not contain more than:
 - i. 0.0015% sulfur by weight (15 ppmw) for ultra-low sulfur diesel;
 - ii. 0.3% sulfur by weight (3,000 ppmw) for ASTM Grade 1 distillate oil;
 - iii. 0.5% sulfur by weight (5,000 ppmw) for ASTM Grade 2 distillate oil;
 - iv. 1.75% sulfur by weight for residual oil (ASTM Grades 4 through 6);

- b. The permittee is allowed to use on-specification used oil that contains no more than 0.5% sulfur by weight (5,000 ppmw). The permittee must obtain analyses from the marketer or, if generated on site, have the used oil analyzed, so that it can be demonstrated that the used oil does not exceed the used oil specifications contained in 40 CFR Part 279.11, Table 1.

3.0 NEW SOURCE PERFORMANCE STANDARDS

- 3.1 **NSPS Applicability** Federal requirements apply to boilers for which construction, modification, or reconstruction is commenced after June 9, 1989 and that have a maximum design heat input capacity of 100 million Btu per hour (MMBtu/hr) or less, but greater than or equal to 10 MMBtu/hr. These requirements are in addition to requirements listed elsewhere in the permit. The full text of the federal standards are found in 40 CFR 60, Subpart Dc. www.ecfr.gov
- 3.2 **NSPS Definitions**
 - a. **Construction** means fabrication, erection, or installation of an affected facility.
 - b. **Modification** means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.
- 3.3 **NSPS Visible Emissions Limit** If oil is combusted in the boiler, and the heat input is greater than 30 MMBtu/hr, the permittee must not cause to be discharged into the atmosphere any gases that exhibit greater than 20% opacity as a 6-minute average, except for one 6-minute period per hour of not more than 27% opacity. The opacity standard applies at all times except during periods of startup, shutdown or malfunction.
- 3.4 **NSPS Visible Emissions Monitoring**
 - a. Visible emissions must be measured and recorded with a continuous opacity monitoring system installed, operated, and maintained in accordance with 40 CFR 60.13 and 60.47c(a) and (b).
 - b. The permittee is not required to operate a COMS provided the boiler burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the permittee operates the unit according to a written site-specific monitoring plan approved by DEQ.
 - i. 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.

- ii. 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 40 CFR 60.8 and 60.11 that the permittee submit any deviations with the excess emissions report required under 40 CFR 60.48c(c).
- c. If not required to use a COMS due to Condition 3.4b, the permittee must conduct a performance test using EPA Method 9 and the procedures in 40 CFR 60.11 to demonstrate compliance with Condition 3.3 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. The observation period for Method 9 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.
- d. The permittee must conduct subsequent Method 9 performance tests using the procedures in Condition 3.4c according to the applicable schedule as follows and as determined by the most recent Method 9 performance test results:
 - i. If no visible emissions are observed, a subsequent Method 9 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 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 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 performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

3.5 NSPS Particulate Matter Emission Limits

For any boiler that has a heat input capacity of 30 MMBtu/hr or greater, and that combusts oil or a mixture of oil with any other fuels, and that commenced construction, reconstruction, or modification after February 28, 2005:

- a. The permittee must not cause to be discharged into the atmosphere any gases that contain particulate matter in excess of 0.030 lbs/MMBtu heat input.
- b. As an alternative to meeting the requirements of Condition 3.5a, particulate matter emissions must not exceed 0.051 lbs/MMBtu heat input and particulate matter emissions must be reduced by 99.8 percent from uncontrolled.
- c. Exemption: Each boiler that combusts only oil that contains no more than 0.50 percent sulfur by weight or a mixture of 0.50 percent sulfur by weight oil with other fuels not subject to the particulate emission limit standard under 40 CFR 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 Condition 3.5a or 3.5b.

3.6 NSPS Particulate Matter Emission Testing

- a. For each boiler subject to the PM and/or opacity standards under Conditions 3.3 and/or 3.5, the permittee must conduct an initial performance test in accordance with 40 CFR 60.45c(a), and must conduct subsequent performance tests as requested by the DEQ, to determine compliance with the standards, except as specified in Condition 3.4.
- b. The permittee must submit to the DEQ the performance test data from the initial and any subsequent performance tests; and
- c. As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in 40 CFR 60.8, conducted to demonstrate compliance with the NSPS, the permittee 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.

- 3.7 NSPS Sulfur Limits** The sulfur content of fuel oil burned in the boiler must not exceed 0.5% by weight.
- 3.8 NSPS Fuel Sulfur Monitoring** Unless an approved alternate monitoring frequency is obtained from the EPA Administrator, the permittee must record and maintain records of the amounts of each fuel combusted during each day in each subject boiler.
- a. Except as specified in Condition 3.8c, if oil is burned, the permittee must maintain records of the sulfur content of the fuel oil either by obtaining fuel supplier certifications or sampling and analyzing the fuel oil in accordance with ASTM procedures.
 - b. If relying on fuel samples for demonstrating compliance with the fuel sulfur content limits, a sample must be collected and analyzed after each shipment of fuel is added to the storage tank.
 - c. For residual oil-fired boilers, the use of fuel supplier certifications to demonstrate compliance are only allowed for boilers with heat input capacities between 10 to 30 MMBtu/hr.
- 3.9 NSPS Boiler Reporting** Unless an approved alternate monitoring frequency is obtained from the EPA Administrator, the permittee must submit semi-annual reports for periods during which oil was burned that include the following information:
- a. The calendar dates covered in the reporting period;
 - b. Each 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; including reasons for any noncompliance with the emission standards; and a description of corrective actions taken.
 - c. 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 oil was not combusted in the steam generating unit.
 - d. If fuel supplier certifications are used to demonstrate compliance, records of fuel supplier certifications that include the following. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the permittee that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

- i. For distillate oil:
 - The name of the oil supplier;
 - A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in 40 CFR 61.41c; and
 - The sulfur content or maximum sulfur content of the oil.
- ii. For residual oil:
 - The name of the oil supplier;
 - 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 facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;
 - The sulfur content of the oil from which the shipment came (or of the shipment itself); and
 - The method used to determine the sulfur content of the oil.
- iii. For other fuels:
 - The name of the oil supplier;
 - The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and
 - The method used to determine the potential sulfur emissions rate of the fuel.

Note: If using ASTM grade 3, include the most relevant information depending on whether the blend exhibits the characteristics of a distillate or residual oil.

- e. If residual oil is burned in the boiler and the heat input is greater than 30 MMBtu/hr, the semi-annual report must include a summary of any excess visible emissions recorded by the COMS.
- f. The initial semi-annual report must be postmarked by the 30th day of the third month following the actual date of startup. Each subsequent semi-annual report must be postmarked by the 30th day following the end of the reporting period (July 30th and January 30th).

- g. If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under Condition 3.9d, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the permittee that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.
- h. For a boiler subject to the opacity limit in Condition 3.3, the permittee must submit excess emission reports for any excess emissions that occur during the reporting period and maintain records according to the following requirements, as applicable to the visible emissions monitoring method used.
 - i. For each performance test conducted using EPA Method 9, the permittee must keep the following records:
 - Dates and time intervals of all opacity observation periods;
 - Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and
 - Copies of all visible emission observer opacity field data sheets.
 - ii. For each performance test conducted using EPA Method 22, the permittee must keep the following records:
 - Dates and time intervals of all visible emissions observation periods;
 - Name and affiliation for each visible emission observer participating in the performance test;
 - Copies of all visible emission observer opacity field data sheets; and
 - Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the permittee to demonstrate compliance with the applicable monitoring requirements.

- iii. For each digital opacity compliance system, the permittee must maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by DEQ.

3.10 NSPS Recordkeeping The permittee must maintain on-site, records of the amount and type of fuels burned each day, unless an alternate frequency is obtained from EPA for a period of at least two (2) years. As an alternative, if combusting only natural gas, fuels using fuel certification in Condition 3.9d to demonstrate compliance with the SO₂ standard, fuels not subject to an emission standard (excluding opacity), or a mixture of these fuels, the permittee may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

3.11 Construction or Modification In addition to the Notice of Intent to Construct (NC) requirement, the permittee must submit a notification that includes the information specified in 40 CFR 60.48c(a) to DEQ and the EPA when equipment becomes subject to NSPS as summarized below:

If	Notification of	Due Date
Constructing or installing a new affected NSPS boiler	The date construction began	Within 30 days of commencing construction
	Actual start-up date	Within 15 days after start-up
Modifying existing equipment	The nature of the change, present and future emissions, productive capacity differences, expected completion date of change	60 days prior to expected completion date

3.12 EPA Submittal Address All submittals to the EPA must be sent to the following address:

Director
Air and Waste Management Division
EPA Region X
Mail Stop OAQ-107
1200 Sixth Avenue, Suite 900
SEATTLE, WA 98101-3123

4.0 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

4.1 NESHAP Applicability

- a. The NESHAP applies to industrial, commercial, or institutional oil-fired boilers.
- b. The NESHAP does not apply to boilers if oil is burned only during periods of gas curtailment, gas supply interruption, startups, or for periodic testing, maintenance, or operator training. Periodic testing, maintenance, or operator training on oil shall not exceed a combined total of 48 hours during any calendar year. Records of elapsed time burning oil must be maintained for 5 years.
- c. A boiler is considered existing if construction or reconstruction of the boiler commenced on or before June 4, 2010.
- d. A boiler is considered new if construction of the boiler commenced after June 4, 2010, and the boiler meets the applicability criteria at the time construction commenced.
- e. A boiler is considered reconstructed if the boiler meets the reconstruction criteria as defined in 40 CFR 63.2, the permittee commenced reconstruction after June 4, 2010, and the boiler meets the applicability criteria at the time reconstruction commenced.
- f. An existing dual-fuel fired boiler meeting the definition of gas-fired boiler, as defined in 40 CFR 63.11237, that meets the applicability requirements of the NESHAP after June 4, 2010 due to a fuel switch from gaseous fuel to solid fossil fuel, biomass, or liquid fuel is considered to be an existing boiler under the NESHAP as long as the boiler was designed to accommodate the alternate fuel.
- g. The NESHAP standards apply at all times the affected boiler is operating, except during periods of startup and shutdown as defined in 40 CFR 63.11237, during which time the permittee must comply only with Table 1.

4.2 NESHAP Particulate Matter Emission Limit

- a. For new or reconstructed oil-fired boilers, that meet the applicability criteria at the time construction commenced, with heat input capacities of 10 MMBtu/hr or greater, and that are not considered seasonal or limited-use boilers, the permittee must achieve less than or equal to 0.030 lbs/ MMBtu of heat input, except during periods of startup and shutdown.
- b. The permittee must demonstrate initial compliance with the emission limit specified in Condition 4.2 by conducting a performance (stack) test according to 40 CFR 63.11212 and Table 2 in Appendix B to this permit.

**4.3 NESHAP Work
Practice Standards**

- a. For new or reconstructed oil-fired boilers with heat input capacity of 10 MMBtu/hr or greater, the permittee must minimize the boiler's startup and shutdown periods and conduct startups and shutdowns according to the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, the permittee must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. The permittee must submit a signed statement in the Notification of Compliance Status report that indicates that they conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available.
- b. For oil-fired boilers with heat input capacity greater than 5 MMBtu/hr that are not seasonal or limited-use boilers and do not use an oxygen trim system that maintains an optimum air-to-fuel ratio, the permittee must conduct a tune-up of the boiler biennially as specified in Condition 4.7. Each biennial tune-up must be conducted no more than 25 months after the previous tune-up. For new or reconstructed boilers, the first biennial tune-up must be no later than 25 months after initial startup of the new or reconstructed boiler. The permittee must submit a signed statement in the Notification of Compliance Status report that indicates that the permittee conducted an initial tune-up of the boiler.
- c. For oil-fired boilers with heat input capacity equal to or less than greater than 5 MMBtu/hr, or oil-fired boilers that are seasonal or limited-use boilers or that use an oxygen trim system that maintains an optimum air-to-fuel ratio, the permittee must conduct a tune-up of the boiler every 5 years as specified in Condition 4.7. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up. For new or reconstructed boilers, the first 5-year tune-up must be no later than 61 months after initial startup. The permittee may delay the burner inspection and inspection of the system controlling the air-to-fuel ratio until the next scheduled unit shutdown, but must inspect each burner and system controlling the air-to-fuel ratio 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. The permittee must submit a signed statement in the Notification of Compliance Status

report that indicates that the permittee conducted an initial tune-up of the boiler.

- d. For oil-fired boilers for which construction or reconstruction commenced on or before June 4, 2010 with a heat input capacity of 10 MMBtu/hr and greater), not including limited-use boilers, the permittee must have a one-time energy assessment performed by a qualified energy assessor in accordance with Table 2 to 40 CFR Part 63 Subpart JJJJJ. Following the energy assessment, the permittee must submit a signed certification in the Notification of Compliance Status report that an energy assessment of the boiler and its energy use systems was completed according to Table 2 to 40 CFR Part 63 Subpart JJJJJ and that the assessment is an accurate depiction of their 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.

4.4 NESHAP General Compliance Requirements

At all times, the permittee must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the permittee to make any further efforts to reduce emissions if levels required by this standard have been achieved.

4.5 NESHAP Initial Compliance Requirements

- a. For boilers located at existing major sources of HAP that limit their potential to emit (*e.g.*, make a physical change or take a permit limit) such that the existing major source becomes an area source, the permittee must comply with the following applicable provisions:
 - i. Any such existing boiler at the existing source must demonstrate compliance with the NESHAP within 180 days of the later of March 21, 2014 or upon the existing major source commencing operation as an area source.
 - ii. Any new or reconstructed boiler at the existing source must demonstrate compliance with the NESHAP within 180 days of the later of March 21, 2011 or startup.
 - iii. Notification of such changes must be submitted according to Condition 4.13.
- b. For existing affected boilers that have not operated on liquid fuel between March 21, 2011 and March 21, 2014, the permittee must comply with the following applicable provisions:

- i. The permittee must complete the initial performance tune-up, if subject to the tune-up requirements in Condition 4.3, by following the procedures described in Condition 4.7 no later than 30 days after the re-start of the affected boiler on solid fossil fuel, biomass, or liquid fuel.
 - ii. The permittee must complete the one-time energy assessment, if subject to the energy assessment requirements, no later than March 21, 2014.
- c. For new or reconstructed affected boilers that are subject to the emission limit in Condition 4.2, the permittee must demonstrate initial compliance with the emission limit no later than 180 days after March 21, 2011 or within 180 days after startup of the source, whichever is later, according to 40 CFR 63.7(a)(2)(ix).
- d. For new or reconstructed oil-fired boilers that commenced construction or reconstruction on or before September 14, 2016, that combust only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a particulate matter (PM) emission limit and that do not use a post-combustion technology (except a wet scrubber) to reduce PM or sulfur dioxide emissions, the permittee is not subject to the PM emission limit in Condition 4.2 until September 14, 2019, providing the permittee monitors and records on a monthly basis the type of fuel combusted. If intending to burn a new type of fuel or fuel mixture that does not meet the requirements of this Condition, the permittee must conduct a performance test within 60 days of burning the new fuel. On and after September 14, 2019, the permittee is subject to the PM emission limit in Condition 4.2 and must demonstrate compliance with the PM emission limit no later than March 12, 2020.
- e. For new or reconstructed boilers that combust only ultra-low-sulfur liquid fuel as defined in 40 CFR 63.11237, the permittee is not subject to the PM emission limit in Condition 4.2 providing the permittee monitors and records on a monthly basis the type of fuel combusted. If intending to burn a fuel other than ultra-low-sulfur liquid fuel or gaseous fuels as defined in 40 CFR 63.11237, the permittee must conduct a performance test within 60 days of burning the new fuel.
- f. For affected boilers that ceased burning solid waste consistent with 40 CFR 63.11196(d) and for which the initial compliance date has passed, the permittee must demonstrate compliance

within 60 days of the effective date of the waste-to-fuel switch as specified in 40 CFR 60.2145(a)(2) and (3) or 40 CFR 60.2710(a)(2) and (3). If having not conducted the compliance demonstration for the NESHAP within the previous 12 months, the permittee must complete all compliance demonstrations for the NESHAP before commencing or recommencing combustion of solid waste.

- g. For affected boilers that switch fuels or make a physical change to the boiler that results in the applicability of a different subcategory within the NESHAP or the boiler becoming subject to the NESHAP, the permittee must demonstrate compliance within 180 days of the effective date of the fuel switch or the physical change. Notification of such changes must be submitted according to Condition 4.13.

4.6 NESHAP Subsequent Testing

- a. If the boiler has a heat input capacity of 10 MMBtu/hr or greater, the permittee must conduct all applicable performance (stack) tests according to 40 CFR 63.11212 on a triennial basis, except as specified in Conditions 4.6b through 4.6d. Triennial performance tests must be completed no more than 37 months after the previous performance test.
- b. For new or reconstructed boilers that commenced construction or reconstruction on or before September 14, 2016, when demonstrating initial compliance with the PM emission limit, if the boiler's performance test results show that the PM emissions are equal to or less than half of the PM emission limit, the permittee does not need to conduct further performance tests for PM until September 14, 2021, but must continue to comply with all applicable operating limits and monitoring requirements and must comply with the following provisions:
 - i. A performance test for PM must be conducted by September 14, 2021.
 - ii. If the performance test results show that the PM emissions are equal to or less than half of the PM emission limit, the permittee may choose to conduct performance tests for PM every fifth year. Each such performance test must be conducted no more than 61 months after the previous performance test.
 - iii. If intending to burn a new type of fuel other than ultra-low-sulfur liquid fuel or gaseous fuels as defined in 40 CFR 63.11237, the permittee must conduct a performance test within 60 days of burning the new fuel type.

- iv. If the performance test results show that the PM emissions are greater than half of the PM emission limit, the permittee must conduct subsequent performance tests on a triennial basis as specified in Condition 4.6a.
- c. For new or reconstructed boilers that commenced construction or reconstruction after September 14, 2016, when demonstrating initial compliance with the PM emission limit, if the boiler's performance test results show that PM emissions are equal to or less than half of the PM emission limit, the permittee may choose to conduct performance tests for PM every fifth year, but must continue to comply with all applicable operating limits and monitoring requirements and must comply with the following provisions:
 - i. Each such performance test must be conducted no more than 61 months after the previous performance test.
 - ii. If intending to burn a new type of fuel other than ultra-low-sulfur liquid fuel or gaseous fuels as defined in 40 CFR 63.11237, the permittee must conduct a performance test within 60 days of burning the new fuel type.
 - iii. If the performance test results show that PM emissions are greater than half of the PM emission limit, the permittee must conduct subsequent performance tests on a triennial basis as specified in Condition 4.6a.
- d. For existing affected boilers that have not operated on solid fossil fuel, biomass, or liquid fuel since the previous compliance demonstration and more than 3 years have passed since the previous compliance demonstration, the permittee must complete subsequent compliance demonstration no later than 180 days after the re-start of the affected boiler on solid fossil fuel, biomass, or liquid fuel.

4.7 NESHAP Tune-up Requirements

The permittee must conduct a performance tune-up for each oil-fired boiler as follows and keep records to demonstrate continuous compliance. The permittee must conduct the tune-up while burning the type of fuel (or fuels in the case of boilers that routinely burn two types of fuels at the same time) that provided the majority of the heat input to the boiler over the 12 months prior to the tune-up.

- a. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the burner inspection

- until the first outage, not to exceed 36 months from the previous inspection.
- b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available.
 - c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown, not to exceed 36 months from the previous inspection). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection.
 - d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any nitrogen oxide requirement to which the unit is subject.
 - e. 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.
 - f. Maintain on-site and submit, if requested by DEQ, a report containing the following information:
 - i. The concentrations of CO in the effluent stream in parts per million, by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler.
 - ii. A description of any corrective actions taken as a part of the tune-up of the boiler.
 - iii. The type and amount of fuel used over the 12 months prior to the tune-up of the boiler, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel use by each unit.
 - g. If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 days of startup.

4.8

**NESHAP
Monitoring,
Installation,
Operation and
Maintenance
Requirements**

- a. If using a control device to comply with the emission limits specified in Condition 4.2, the permittee must maintain each operating limit in Table 1 in Appendix B to this permit that applies to the boiler as specified in Table 4 in Appendix B to this permit. If using a control device not covered in Table 1 in Appendix B to this permit, or if wishing to establish and monitor an alternative operating limit and alternative monitoring parameters, the permittee must apply to the EPA Administrator for approval of alternative monitoring under 40 CFR 63.8(f).
- b. If demonstrating compliance with any applicable emission limit through performance (stack) testing and subsequent compliance with operating limits (including the use of CPMS) or with a COMS, the permittee must develop a site-specific monitoring plan according to 40 CFR 63.11205(c) and 63.11224(c) and install, operate, and maintain each required CPMS according to Conditions 4.8e, 4.8f and 4.8g, as applicable. This requirement also applies if petitioning to the EPA Administrator for alternative monitoring parameters under 40 CFR 63.8(f). This requirement also applies if the permittee petitions the EPA Administrator for alternative monitoring parameters under 40 CFR 63.8(f).
- c. The permittee must conduct a performance evaluation of each CMS in accordance with their site-specific monitoring plan.
- d. The permittee must monitor and collect data as follows and the site-specific monitoring plan required by Condition 4.8b.
 - i. The permittee must operate the monitoring system and collect data at all required intervals at all times the affected source is operating and compliance is required, except for periods of monitoring system malfunctions or out-of-control periods (see 40 CFR 63.8(c)(7)), repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in their 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.
- ii. The permittee may not use data collected 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 quality control activities in calculations used to report emissions or operating levels. Any such periods must be reported according to the requirements in Condition 4.11. The permittee must use all the data collected during all other periods in assessing the operation of the control device and associated control system.
 - iii. Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in the site-specific monitoring plan), failure to collect required data is a deviation of the monitoring requirements.
- e. If having an operating limit that requires the use of a CMS, the permittee must install, operate, and maintain each CPMS according to the following procedures:
- i. The CPMS must complete a minimum of one cycle of operation every 15 minutes. The permittee must have data values from a minimum of four successive cycles of operation representing each of the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed, to have a valid hour of data.
 - ii. The permittee must calculate hourly arithmetic averages from each hour of CPMS data in units of the operating limit and determine the 30-day rolling average of all recorded readings, except as provided in Condition 12.8d.ii. Calculate a 30-day rolling average from all of the hourly averages collected for the 30-day operating period using the following equation:

$$30 - \text{day average} = \frac{\sum_{i=1}^n Hpvi}{n}$$

Where:

Hpvi = the hourly parameter value for hour i;

n = the number of valid hourly parameter values collected over 30 boiler operating days.

- iii. For purposes of collecting data, the permittee must operate the CPMS as specified in Condition 12.8d.i. For purposes of calculating data averages, the permittee must use all the data collected during all periods in assessing compliance, except that the permittee must exclude certain data as specified in Condition 12.8d.ii. Periods when CPMS data are unavailable may constitute monitoring deviations as specified in Condition 12.8d.iii.
 - iv. Record the results of each inspection, calibration, and validation check.
 - f. If having an applicable opacity operating limit under the NESHAP, the permittee must install, operate, certify and maintain each COMS according to the following procedures:
 - i. Each COMS must be installed, operated, and maintained according to Performance Specification 1 of 40 CFR Part 60, appendix B.
 - ii. The permittee must conduct a performance evaluation of each COMS according to the requirements in 40 CFR 63.8 and according to Performance Specification 1 of 40 CFR Part 60, appendix B.
 - iii. As specified in 40 CFR 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.
 - iv. The COMS data must be reduced as specified in 40 CFR 63.8(g)(2).
 - v. The permittee must include in their site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in 40 CFR 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.

- vi. The permittee must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of 40 CFR 63.8(e). The permittee 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.
 - vii. The permittee must calculate and record 6-minute averages from the opacity monitoring data and determine and record the daily block average of recorded readings, except as provided in Condition 12.8d.ii.
 - viii. For purposes of collecting opacity data, the permittee must operate the COMS as specified in Condition 12.8d.i. For purposes of calculating data averages, the permittee must use all the data collected during all periods in assessing compliance, except that the permittee must exclude certain data as specified in Condition 12.8d.ii. Periods when COMS data are unavailable may constitute monitoring deviations as specified in Condition 12.8d.iii.
- g. If using a fabric filter bag leak detection system to comply with the requirements of the NESHAP, the permittee must install, calibrate, maintain, and continuously operate the bag leak detection system as follows:
- i. The permittee must install and operate a bag leak detection system for each exhaust stack of the fabric filter.
 - ii. Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with EPA-454/R-98-015.
 - iii. The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.
 - iv. The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

- v. The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.
- vi. The bag leak detection system must be equipped with an audible or visual alarm system that will activate automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard or seen by plant operating personnel.
- vii. For positive pressure fabric filter systems that do not duct all compartments or cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.
- viii. Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.

**4.9 NESHAP
Demonstrating
Continuous
Compliance with the
Emission Limits**

- a. The permittee must demonstrate continuous compliance with the emission limit and applicable operating limit in Condition 4.2 and Table 1 in Appendix B to this permit according to the methods specified in Table 3 in Appendix C to this permit as follows:
 - i. Following the date on which the initial compliance demonstration is completed or is required to be completed, whichever date comes first, the permittee must continuously monitor the operating parameters. Operation above the established maximum, below the established minimum, or outside the allowable range of the operating limits constitutes a deviation from the operating limits established under this NESHAP, except during performance tests conducted to determine compliance with the emission and operating limits or to establish new operating limits. Operating limits are confirmed or reestablished during performance tests.
 - ii. The permittee must keep records of the type and amount of all fuels burned in each boiler during the reporting period.
 - iii. If the unit is controlled with a fabric filter and demonstrating continuous compliance using a bag leak detection system, the permittee must initiate corrective action within 1 hour of a bag leak detection system alarm and operate and maintain the fabric filter system such that the alarm does not sound more than 5 percent

of the operating time during a 6-month period. The permittee must also keep records of the date, time, and duration of each alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken. The permittee must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm is counted as a minimum of 1 hour. If taking longer than 1 hour to initiate corrective action, the alarm time is counted as the actual amount of time taken to initiate corrective action.

- b. The permittee must report each instance in which the permittee did not meet each emission limit and operating limit in Condition 4.2 and Tables 1 that apply. These instances are deviations from the emission limits in the NESHAP. These deviations must be reported according to the requirements in Condition 4.11.

4.10 NESHAP Notification

- a. The permittee must submit all of the notifications in 40 CFR 63.7(b); 63.8(e) and (f); and 63.9(b) through (e), (g), and (h) that apply by the dates specified in those sections.
- b. An Initial Notification must be submitted no later than January 20, 2014 or within 120 days after the boiler becomes subject to the standard.
- c. If required to conduct a performance stack test, the permittee must submit a Notification of Intent to conduct a performance test at least 60 days before the performance stack test is scheduled to begin.
- d. The permittee must submit the Notification of Compliance Status no later than July 19, 2014 unless owning or operating a new boiler subject only to a requirement to conduct a biennial or 5-year tune-up or a performance stack test. If owning or operating a new boiler subject to a requirement to conduct a tune-up, the permittee is not required to prepare and submit a Notification of Compliance Status for the tune-up. If the permittee must conduct a performance stack test, the permittee must submit the Notification of Compliance Status within 60 days of completing the performance stack test. The permittee must submit the Notification of Compliance Status as follows. The Notification of Compliance Status must include the

information and certification(s) of compliance as follows, and as applicable, and signed by a responsible official.

- i. The permittee must submit the information required in 40 CFR 63.9(h)(2), except the information listed in 40 CFR 63.9(h)(2)(i)(B), (D), (E), and (F). If conducting any performance tests or CMS performance evaluations, the permittee must submit that data as specified in 40 CFR 63.11225(e). If conducting any opacity or visible emission observations, or other monitoring procedures or methods, the permittee must submit that data to the Administrator at the appropriate address listed in 40 CFR 63.13.
 - ii. “This facility complies with the requirements in 40 CFR 63.11214 to conduct an initial tune-up of the boiler.”
 - iii. “This facility has had an energy assessment performed according to 40 CFR 63.11214(c).”
 - iv. For units that install bag leak detection systems: “This facility complies with the requirements in 40 CFR 63.11224(f).”
 - v. For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: “No secondary materials that are solid waste were combusted in any affected unit.”
 - vi. The notification must be submitted electronically using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to the NESHAP is not available in CEDRI at the time that the report is due, the written Notification of Compliance Status must be submitted to the EPA Administrator and DEQ at the appropriate address listed in 40 CFR 63.13.
- e. If using data from a previously conducted emission test to serve as documentation of conformance with the emission standards and operating limits of the NESHAP, the permittee must include in the Notification of Compliance Status the date of the test and a summary of the results, not a complete test report, relative to the NESHAP.

- 4.11 NESHAP Reporting** The permittee must prepare, by March 1 of each year, and submit to DEQ, an annual compliance certification report for the previous calendar year containing the following information. The permittee must submit the report by March 15 if there were any instances described by

Condition 4.11c. For boilers that are subject only to the energy assessment requirement and/or a requirement to conduct a biennial or 5-year tune-up according to Condition 4.7 and not subject to emission limits or operating limits, the permittee may prepare only a biennial or 5-year compliance report.

- a. Company name and address.
- b. Statement by a responsible official, with the official's name, title, phone number, email address, and signature, certifying the truth, accuracy and completeness of the notification and a statement of whether the source has complied with all the relevant standards and other requirements of the NESHAP. The notification must include the following certification(s) of compliance, as applicable, and signed by a responsible official:
 - i. "This facility complies with the requirements in 40 CFR 63.11223 to conduct a biennial or 5-year tune-up, as applicable, of each boiler."
 - ii. For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: "No secondary materials that are solid waste were combusted in any affected unit."
 - iii. "This facility complies with the requirement in 40 CFR 63.11214(d) and 63.11223(g) to minimize the boiler's time spent during startup and shutdown and to conduct startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available."
- c. If the source experiences any deviations from the applicable requirements during the reporting period, include a description of deviations, the time periods during which the deviations occurred, and the corrective actions taken.
- d. The total fuel use by each affected boiler subject to an emission limit, for each calendar month within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the permittee or EPA through a petition process to be a non-waste under 40 CFR 241.3(c), whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and the total fuel usage amount with units of measure.

4.12 NESHAP Recordkeeping

- a. The permittee must keep records to document conformance with the work practices, emission reduction measures, and management practices as follows:
 - i. Records must identify each boiler, the date of tune-up, the procedures followed for tune-up, and the manufacturer's specifications to which the boiler was tuned.
 - ii. For operating units that combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), the permittee must keep a record which documents how the secondary material meets each of the legitimacy criteria under 40 CFR 241.3(d)(1). If combusting a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(4), the permittee must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2 and each of the legitimacy criteria in 40 CFR 241.3(d)(1). If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), the permittee 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 40 CFR 241.4, the permittee must keep records documenting that the material is a listed non-waste under 40 CFR 241.4(a).
 - iii. For each boiler required to conduct an energy assessment, the permittee must keep a copy of the energy assessment report.
 - iv. For each boiler subject to an emission limit in Condition 4.2, the permittee must keep records of monthly fuel use by each boiler, including the type(s) of fuel and amount(s) used. For each new oil-fired boiler that meets the requirements of Condition 4.5d and 4.5e, the permittee must keep records, on a monthly basis, of the type of fuel combusted.
 - v. For each boiler that meets the definition of seasonal boiler, the permittee must keep records of days of operation per year.
 - vi. For each boiler that meets the definition of limited-use boiler, the permittee must keep a copy of the federally enforceable permit that limits the annual capacity factor

to less than or equal to 10 percent and records of fuel use for the days the boiler is operating.

- b. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation that were done to demonstrate compliance with the mercury emission limits. Supporting documentation should include results of any fuel analyses. The permittee can use the results from one fuel analysis for multiple boilers provided they are all burning the same fuel type.
- c. Records of the occurrence and duration of each malfunction of the boiler, or of the associated air pollution control and monitoring equipment.
- d. Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in Condition 4.4, including corrective actions to restore the malfunctioning boiler, air pollution control, or monitoring equipment to its normal or usual manner of operation.
- e. The permittee must keep the records of all inspection and monitoring data required by Condition 4.8d and 4.8e, and the following information for each required inspection or monitoring:
 - i. The date, place, and time of the monitoring event.
 - ii. Person conducting the monitoring.
 - iii. Technique or method used.
 - iv. Operating conditions during the activity.
 - v. Results, including the date, time, and duration of the period from the time the monitoring indicated a problem to the time that monitoring indicated proper operation.
 - vi. Maintenance or corrective action taken (if applicable).
- f. If using a bag leak detection system, the permittee must keep the following records:
 - i. Records of the bag leak detection system output.
 - ii. Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings.
 - iii. The date and time of all bag leak detection system alarms, and for each valid alarm, the time corrective

action was initiated, the corrective action taken, and the date on which corrective action was completed.

4.13 NESHAP Fuel Switch or Physical Change Notification

- a. If having switched fuels or made a physical change to the boiler and the fuel switch or change resulted in the applicability of a different subcategory within the NESHAP, in the boiler becoming subject to the NESHAP, or in the boiler switching out of the NESHAP due to a fuel change that results in the boiler meeting the definition of gas-fired boiler, as defined in 40 CFR 63.11237, the permittee must provide notice of the date upon which they switched fuels, made the physical change, or took a permit limit within 30 days of the change. The notification must identify:
 - b. The name of the permittee, the location of the source, the boiler(s) that have switched fuels, were physically changed, or took a permit limit, and the date of the notice.
 - c. The date upon which the fuel switch, physical change, or permit limit occurred.

5.0 OPERATION AND MAINTENANCE REQUIREMENTS

5.1 Work practices

The permittee must perform a maintenance service on each boiler at least once in every 2-year period. As a minimum, the service must include an inspection of the burners and refractory chamber; cleaning, adjustment, and repair as necessary. For water tube boilers, the service must include flushing the tubes.

5.2 Fugitive Emissions Control Plan

While operating in the Medford-Ashland AQMA, the permittee must prepare and implement site-specific plans for the control of fugitive emissions in accordance with OAR 340-240-0180. While operating in the Lakeview Urban Growth Area (UGA), the permittee must prepare and implement site-specific plans for the control of fugitive emissions in accordance with OAR 340-240-0410.

5.3 O&M plan

While operating in the Medford-Ashland AQMA, the permittee must prepare and implement an operation and maintenance (O&M) plan in accordance with OAR 340-240-0190. While operating in the Lakeview UGA, the permittee must prepare and implement an O&M plan in accordance with OAR 340-240-0420.

6.0 PLANT SITE EMISSION LIMITS

6.1 Plant Site Emission Limits (PSEL)

Plant site emissions must not exceed the following:

Pollutant	Limit	Units
PM	24	tons per year
PM ₁₀	14	tons per year
PM _{2.5}	9	tons per year
SO ₂	39	tons per year
NO _x	39	tons per year
CO	99	tons per year
VOC	39	tons per year
GHGs (CO ₂ e)	74,000	tons per year

6.2 PM₁₀ PSEL for Medford-Ashland AQMA

For sources operating in the Medford-Ashland AQMA, plant site emissions of PM₁₀ must not exceed the following:

Pollutant	Limit	Units
PM ₁₀	4.5	tons per year
	49	pounds per day

6.3 Annual Period

The annual plant site emissions limits apply to any 12-consecutive calendar month period.

7.0 COMPLIANCE DEMONSTRATION

7.1 PSEL Compliance Monitoring

Compliance with the PSEL is determined for each 12-consecutive calendar month period based on the following calculation for each pollutant:

$$E = \Sigma(EF \times F)/2000 \text{ lbs}$$

where,

- E = pollutant emissions (ton/yr);
- Σ = symbol representing “summation of”;
- EF = pollutant emission factor (see Condition 7.2);
- F = quantity of fuel burned (million cubic feet of natural gas or 1000 gallons of oil, propane, or butane)

7.2 Emission Factors

The permittee must use the default emission factors provided in Appendix A of this permit for calculating pollutant emissions, unless alternative emission factors are approved by DEQ. The permittee may request or DEQ may require using alternative emission factors provided they are based on actual test data or other documentation (e.g., AP-42 compilation of emission factors) that has been reviewed and approved by DEQ.

8.0 RECORDKEEPING REQUIREMENTS

8.1 Operation and Maintenance

The permittee must maintain the following records related to the operation and maintenance of the plant and associated air contaminant control devices:

- a. Maintenance log and operation and maintenance plan as required in Section 3.0; and
- b. Sulfur content of fuel oil used at the plant.
- c. Sulfur content and analysis of used oil, as required by Condition 2.6b; and
- d. Daily (Medford/Ashland AQMA only), monthly and annual usage of fuels by type and quantity.

8.2 Excess Emissions

The permittee must maintain records of excess emissions as defined in OAR 340-214-0300 through 340-214-0340 (recorded on occurrence). Typically, excess emissions are caused by process upsets, startups, shutdowns, or scheduled maintenance.

8.3 Complaint Log

The permittee must maintain a log of all written complaints and complaints received via telephone that specifically refer to air pollution concerns associated to the permitted facility. The log must include a record of the permittee's actions to investigate the validity of each complaint and a record of actions taken for complaint resolution.

8.4 Retention of Records

Unless otherwise specified, all records must be maintained on site for a period of five (5) years and made available to the DEQ upon request.

9.0 REPORTING REQUIREMENTS

9.1 Excess Emissions

The permittee must notify DEQ by telephone or in person of any excess emissions which are of a nature that could endanger public health.

- a. Such notice must be provided as soon as possible, but never more than one hour after becoming aware of the problem. Notice must be made to the regional office identified in Condition 10.3.

- b. If the excess emissions occur during non-business hours, the permittee must notify DEQ by calling the Oregon Emergency Response System (OERS). The current number is 1-800-452-0311.
- c. The permittee must also submit follow-up reports when required by DEQ.

9.2 Annual Report

The permittee must submit to DEQ by **February 15** of each year this permit is in effect, two (2) copies of the following information for the preceding calendar year:

- a. Operating parameters:
 - i. For sources operating in the Medford/Ashland AQMA, the maximum daily amount of each type of fuel burned;
 - ii. Type and quantity of fuels burned on an annual basis; and
 - iii. Annual emissions as calculated according to Condition 7.1.
- b. Records of all planned and unplanned excess emissions events.
- c. Summary of complaints relating to air quality received by permittee during the year.
- d. List permanent changes made in plant process, production levels, and pollution control equipment which affected air contaminant emissions.
- e. List major maintenance performed on pollution control equipment.

9.3 Greenhouse Gas Registration and Reporting

If the calendar year emission rate of greenhouse gases (CO₂e) is greater than or equal to 2,756 tons (2,500 metric tons), the permittee must register and report its greenhouse gas emissions with DEQ in accordance with OAR 340-215.

9.4 Initial Startup Notice

The permittee must notify DEQ in writing of the date a new facility is started up. The notification must be submitted no later than seven (7) days after startup.

9.5 Notice of Change of Ownership or Company Name

The permittee must notify DEQ in writing using a DEQ "Permit Application Form" within 60 days after the following:

- a. Legal change of the name of the company as registered with the Corporations Division of the State of Oregon; or
- b. Sale or exchange of the activity or facility.

- 9.6 Construction or Modification Notices** The permittee must notify DEQ in writing using a DEQ “Notice of Construction Form,” or “Permit Application Form,” and obtain approval in accordance with OAR 340-210-0205 through 340-210-0250 before:
- Constructing or installing any new source of air contaminant emissions, including air pollution control equipment;
 - Modifying or altering an existing source that may significantly affect the emission of air contaminants;
 - Making any physical change which increases emissions; or
 - Changing the method of operation, the process, or the fuel use, or increasing the normal hours of operation that result in increased emissions.
- 9.7 Where to Send Reports and Notices** Reports and notices, with the permit number prominently displayed, must be sent to the Permit Coordinator for the regional office where the source is located as identified in Condition 10.2.

10.0 ADMINISTRATIVE REQUIREMENTS

- 10.1 Reassignment to the General ACDP** A complete application for reassignment to this permit is due within 30 days after the permit is reissued. DEQ will notify the permittee when the permit is reissued. The application must be sent to the appropriate regional office.
- If DEQ is delinquent in renewing the permit, the existing permit will remain in effect and the permittee must comply with the conditions of the permit until such time that the permit is reissued and the source is reassigned to the permit.
 - The permittee may submit an application for either a Simple or Standard ACDP at any time, but the permittee must continue to comply with the General ACDP until DEQ takes final action on the Simple or Standard ACDP application.
 - If a complete application for reassignment to the General ACDP or Simple or Standard ACDP is filed with DEQ in a timely manner, the permit will not be deemed to expire until final action has been taken on the application.
- 10.2 Permit Coordinator Addresses** All reports, notices, and applications should be directed to the Permit Coordinator for the area where the source is located. The Permit Coordinator addresses are as follows:

Counties	Permit Coordinator Address and Telephone
Clackamas, Clatsop, Columbia, Multnomah, Tillamook, and Washington	Department of Environmental Quality Northwest Region 700 NE Multnomah Street, Suite 600 Portland, OR 97232 Telephone: (503) 229-5696
Benton, Coos, Curry, Douglas, Jackson, Josephine, Lincoln, Linn, Marion, Polk, and Yamhill	Department of Environmental Quality Western Region 4026 Fairview Industrial Drive Salem, OR 97302 Telephone: (503) 378-8240 ext. 225
Baker, Crook, Deschutes, Gilliam, Grant, Harney, Hood River, Jefferson, Klamath, Lake, Malheur, Morrow, Sherman, Umatilla, Union, Wallowa, Wasco, Wheeler	Department of Environmental Quality Eastern Region 475 NE Bellevue, Suite 110 Bend, OR 97701 Telephone: (541) 388-6146 ext. 223

10.3 DEQ Contacts

Information about air quality permits and DEQ's regulations may be obtained from the DEQ web page at <http://www.oregon.gov/deq/>. All inquiries about this permit should be directed to the regional office for the area where the source is located. DEQ's regional offices are as follows:

Counties	Office Address and Telephone
Clackamas, Clatsop, Columbia, Multnomah, Tillamook, and Washington	Department of Environmental Quality Northwest Region 700 NE Multnomah Street, Suite 600 Portland, OR 97232 Telephone: (503) 229-5696
Benton, Lincoln, Linn, Marion, Polk, and Yamhill	Department of Environmental Quality Salem Office 4026 Fairview Industrial Drive Salem, OR 97302 Telephone: (503) 378-8240
Coos, Curry, and Western Douglas	Department of Environmental Quality Coos Bay Office 381 N Second Street Coos Bay, OR 97420 Telephone: (541) 269-2721
Eastern Douglas, Jackson, and Josephine	Department of Environmental Quality Medford Office 221 Stewart Ave, Suite 201 Medford, OR 97501 Telephone: (541) 776-6010

Counties	Office Address and Telephone
Crook, Deschutes, Harney, Hood River, Jefferson, Klamath, Lake, Sherman, Wasco, and Wheeler	Department of Environmental Quality Bend Office 475 NE Bellevue, Suite 110 Bend, OR 97701 Telephone: (541) 388-6146
Baker, Gilliam, Grant, Malheur, Morrow, Umatilla, Union, and Wallowa	Department of Environmental Quality Pendleton Office 800 SE Emigrant Avenue, Suite 330 Pendleton, OR 97801 Telephone: (541) 276-4063

11.0 FEES

- 11.1 Annual Compliance Fee** The Annual Compliance Determination Fee specified in OAR 340-216-8020, Table 2, Part 2c for a Class Two General ACDP is due on **December 1** of each year this permit is in effect. An invoice indicating the amount, as determined by DEQ regulations, will be mailed prior to the above date.
- 11.2 Change of Ownership or Company Name Fee** The non-technical permit modification fee specified in OAR 340-216-8020, Table 2, Part 3a is due with an application for changing the ownership or the name of the company of a source assigned to this permit.
- 11.3 Where to Submit Fees** Fees must be submitted to:
Department of Environmental Quality
Accounting / Revenue
700 NE Multnomah Street, Suite 600
Portland, Oregon 97232

12.0 GENERAL CONDITIONS AND DISCLAIMERS

- 12.1 Other Regulations** In addition to the specific requirements listed in this permit, the permittee must comply with all other legal requirements enforceable by DEQ.
- 12.2 Conflicting Conditions** In any instance in which there is an apparent conflict relative to conditions in this permit, the most stringent conditions apply.
- 12.3 Masking of Emissions** The permittee must not cause or permit the installation of any device or use any means designed to mask the emissions of an air contaminant that causes or is likely to cause detriment to health, safety, or welfare of any person or otherwise violate any other regulation or requirement.



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| 12.4 DEQ Access | The permittee must allow DEQ's representatives access to the plant site and pertinent records at all reasonable times for the purposes of performing inspections, surveys, collecting samples, obtaining data, reviewing and copying air contaminant emissions discharge records and conducting all necessary functions related to this permit in accordance with ORS 468.095. |
| 12.5 Permit Availability | The permittee must have a copy of the permit available at the facility at all times. |
| 12.6 Open Burning | The permittee must not conduct any open burning except as allowed by OAR 340 Division 264. |
| 12.7 Asbestos | The permittee must comply with the asbestos abatement requirements in OAR 340, Division 248 for all activities involving asbestos-containing materials, including, but not limit to, demolition, renovation, repair, construction, and maintenance. |
| 12.8 Property Rights | The issuance of this permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations. |
| 12.9 Permit, Termination, Revocation, or Modification | DEQ may modify or revoke this permit pursuant to OAR 340-216-0060(3) and (4), and 340-216-0082. |

13.0 ABBREVIATIONS, ACRONYMS, AND DEFINITIONS

ACDP	Air Contaminant Discharge Permit	NESHAP	National Emissions Standards for Hazardous Air Pollutants
ASTM	American Society for Testing and Materials	NO _x	nitrogen oxides
AQMA	Air Quality Maintenance Area	NSPS	New Source Performance Standard
bbbl	barrel (42 gal)	NSR	New Source Review
Btu	British thermal unit	O ₂	oxygen
calendar year	The 12-month period beginning January 1st and ending December 31st	OAR	Oregon Administrative Rules
CDX	Central Data Exchange	ORS	Oregon Revised Statutes
CEDRI	Compliance and Emissions Data Reporting Interface	O&M	operation and maintenance
CEMS	Continuous Emission Monitoring System	Pb	lead
CFR	Code of Federal Regulations	PCD	pollution control device
CMS	Continuous Monitoring System	PM	particulate matter
CPMS	Continuous Parameter Monitoring System	PM ₁₀	particulate matter less than 10 microns in size
CO	carbon monoxide	PM _{2.5}	particulate matter less than 2.5 microns in size
CO ₂	carbon dioxide	ppm	part per million
CO ₂ e	carbon dioxide equivalent	ppmv	part per million by volume
COMS	Continuous Opacity Monitoring System	PSD	Prevention of Significant Deterioration
Date	mm/dd/yy	PSEL	Plant Site Emission Limit
DEQ	Oregon Department of Environmental Quality	PTE	Potential to Emit
dscf	dry standard cubic foot	RACT	Reasonably Available Control Technology
EPA	US Environmental Protection Agency	scf	standard cubic foot
FCAA	Federal Clean Air Act	SER	Significant Emission Rate
Gal	gallon(s)	SERP	Source Emission Reduction Plan
GHGs	Greenhouse gasses in CO ₂ equivalent	SIC	Standard Industrial Code
gr/dscf	grains per dry standard cubic foot	SIP	State Implementation Plan
HAP	Hazardous Air Pollutant as defined by OAR 340-244-0040	SO ₂	sulfur dioxide
ID	identification number	Special Control Area	as defined in OAR 340-204-0070
I&M	inspection and maintenance	UGA	Urban Growth Area
Lb	pound(s)	VE	visible emissions
MMBtu	million British thermal units	VOC	volatile organic compound
NA	not applicable	year	A period consisting of any 12-consecutive calendar months

APPENDIX A: EMISSION FACTORS

Emission Factors (EF) for Boilers

Fuel type	Boiler type or controls	EF units	PM	PM ₁₀	PM _{2.5}	SO ₂	NO _x	CO	VOC
Natural Gas	Uncontrolled	lb/million cubic feet	2.5	2.5	2.5	1.7	100	84	5.5
	Low NO _x burners	lb/million cubic feet	2.5	2.5	2.5	1.7	50	84	5.5
	Flue gas recirculation	lb/million cubic feet	2.5	2.5	2.5	1.7	32	84	5.5
Propane	All	lb/1000 gallons	0.6	0.6	0.6	0.10S ¹	19	3.2	0.5
Butane	All	lb/1000 gallons	0.6	0.6	0.6	0.09S ¹	21	3.6	0.6
#1 distillate oil	All	lb/1000 gallons	3.3	2.3	1.6	42.6	18	5	0.2
#2 distillate oil	All	lb/1000 gallons	3.3	2.3	1.6	71	20	5	0.2
#4 residual oil	All	lb/1000 gallons	8.5	7.5	5.4	263	20	5	0.2
#5 residual oil	All	lb/1000 gallons	11.5	10.1	7.1	275	55	5	0.28
#6 residual oil	All	lb/1000 gallons	20.8	18.2	12.4	275	55	5	0.28

¹The sulfur dioxide emission factor is based on the sulfur content of the fuel expressed as a percent by weight. For example, if the sulfur content of #1 distillate oil is 0.3%, the emission factor is $142 \times 0.3 = 42.6$ lb/1000 gallons of oil burned.

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APPENDIX B: AREA SOURCES NESHAP FOR INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS (40 CFR PART 63 SUBPART JJJJJJ)

Table 1 - Operating Limits for Boilers with Emission Limit

If demonstrating compliance with applicable emission limits using...	The permittee must meet these operating limits except during periods of startup and shutdown...
1. Fabric filter control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR b. Install and operate a bag leak detection system according to Condition 4.8g and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period.
2. Electrostatic precipitator control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR b. Maintain the 30-day rolling average total secondary electric power of the electrostatic precipitator at or above the minimum total secondary electric power as defined in 40 CFR 63.11237.
3. Wet scrubber control	Maintain the 30-day rolling average pressure drop across the wet scrubber at or above the minimum scrubber pressure drop as defined in 40 CFR 63.11237 and the 30-day rolling average liquid flow rate at or above the minimum scrubber liquid flow rate as defined in 40 CFR 63.11237.
4. Any other add-on air pollution control type	This option is for boilers that operate dry control systems. Boilers must maintain opacity to less than or equal to 10 percent opacity (daily block average).
5. Performance stack testing	For boilers that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance test.

Table 2 - Performance (Stack) Testing Requirements

To conduct a performance test for the following pollutant...	The permittee must...	Using...
PM.....	a. Select sampling ports location and the number of traverse points. b. Determine velocity and volumetric flow-rate of the stack gas. c. Determine oxygen and carbon dioxide concentration of the stack gas.	Method 1 in appendix A-1 to 40 CFR part 60. Method 2, 2F, or 2G in appendix A-2 to 40 CFR part 60. Method 3A or 3B in appendix A-2 to 40 CFR part 60, or ASTM D6522-00 (Re-approved 2005), or ANSI/ASME PTC 19.10-1981.

	d. Measure the moisture content of the stack gas.	Method 4 in appendix A-3 to 40 CFR part 60.
	e. Measure the PM emission concentration.	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A-3 or A-6 to 40 CFR part 60 and a minimum 1 dscm of sample volume per run.
	f. Convert emissions concentration to lb/MMBtu emission rates.	Method 19 F-factor methodology in appendix A-7 to 40 CFR part 60.

Table 3 - Establishing Operating Limits

If having an applicable emission limit for...	And the operating limits are based on...	The permittee must...	Using...	According to the following requirements
1. PM	a. Wet scrubber operating parameters	Establish site-specific minimum scrubber pressure drop and minimum scrubber liquid flow rate operating limits according to 40 CFR 63.11211(b)	Data from the pressure drop and liquid flow-rate monitors and the PM performance stack tests	<p>i. The permittee must collect scrubber pressure drop and liquid flow-rate data every 15 minutes during the entire period of the performance stack tests.</p> <p>ii. Determine the average pressure drop and liquid flow-rate for each individual test run in three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.</p>
	b. Electrostatic precipitator operating parameters	Establish a site-specific minimum total secondary electric power operating limit input according to 40 CFR 63.11211(b)	Data from the secondary electric power monitors and the PM performance stack tests	<p>i. The permittee must collect secondary electric power data every 15 minutes during the entire period of the performance stack tests.</p> <p>ii. Determine the average total secondary electric power for each</p>

				individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
2. Any pollutant for which compliance is demonstrated by a performance test	Boiler operating load	Establish a unit-specific limit for maximum operating load according to 40 CFR 63.11212(c)	Data from the operating load monitors (fuel feed monitors or steam generation monitors)	<p>i. The permittee must collect operating load data (fuel feed rate or steam generation data) every 15 minutes during the entire period of the performance test.</p> <p>ii. Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.</p> <p>iii. Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as the operating limit.</p>

Table 4 - Demonstrating Continuous Compliance

If the permittee must meet the following operating limits...	The permittee must demonstrate continuous compliance by...
1. Opacity.	<p>a. Collecting the opacity monitoring system data according to Conditions 4.8d and 4.8f; and</p> <p>b. Reducing the opacity monitoring data to 6-minute averages; and</p> <p>c. Maintaining opacity to less than or equal to 10 percent (daily block average).</p>
2. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to Condition 4.8g and operating the fabric filter such that the requirements in Condition iii are met.

3. Wet Scrubber Pressure Drop and Liquid Flow-rate	<p>a. Collecting the pressure drop and liquid flow rate monitoring system data according to Condition 4.8; and</p> <p>b. Reducing the data to 30-day rolling averages; and</p> <p>c. Maintaining the 30-day rolling average pressure drop and liquid flow rate at or above the minimum pressure drop and minimum liquid flow rate according to 40 CFR 63.11211.</p>
4. Dry Scrubber Sorbent or Activated Carbon Injection Rate	<p>a. Collecting the sorbent or activated carbon injection rate monitoring system data for the dry scrubber according to Condition 4.8; and</p> <p>b. Reducing the data to 30-day rolling averages; and</p> <p>c. Maintaining the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent or activated carbon injection rate according to 40 CFR 63.11211.</p>
5. Electrostatic Precipitator Total Secondary Electric Power	<p>a. Collecting the total secondary electric power monitoring system data for the electrostatic precipitator according to Condition 4.8; and</p> <p>b. Reducing the data to 30-day rolling averages; and</p> <p>c. Maintaining the 30-day rolling average total secondary electric power at or above the minimum secondary electric power according to 40 CFR 63.11211.</p>
6. Boiler operating load	<p>a. Collecting operating load data (fuel feed rate or steam generation data) every 15 minutes; and</p> <p>b. Reducing the data to 30-day rolling averages; and</p> <p>c. Maintaining the 30-day rolling average at or below the operating limit established during the performance test according to 40 CFR 63.11212(c) and Table 3.</p>