State of Oregon Department of Environmental Quality

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 10, 2017
Lydia Emer, Operations Division Administrator	Dated

Sawmill, planing mill, or millwork (including kitchen cabinets and structural members), 25,000 or more board feet per shift of finished product and plywood manufacturing and/or veneer drying. NAICS 221330, 321113, 321211, 321212, 321213, 321214, 321911, 321912, 321918, 321920, 321999, 337110, 337215. SIC 2421, 2426, 2431, 2434, 2435, 2436, 2439, or 4961.

TABLE OF CONTENTS

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 performing activities listed on the cover page, including sawing, planing, sanding, chipping, kiln drying, plywood pressing and surface coating along with supporting activities such as material conveyors (mechanical and pneumatic), veneer dryers, and boilers.

b. The permittee does not operate a wood-fired boiler with a maximum design heat input capacity of greater than or equal to 30 MMBtu/hr.

c. A Simple or Standard ACDP is not required for the source.

d. 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

The permittee is allowed 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air contaminant source(s) listed on the first page of this permit until this permit expires, is modified, revoked or rescinded as long as the permittee complies with the conditions of this permit. 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 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, other than wood-fired boilers, 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, other than wood-fired boilers, installed, constructed or modified on or after June 1, 1970 or from any source located inside a special control area must not equal or exceed an average of 20 percent opacity.

c. Visible emissions from wood-fired boilers installed, constructed or modified prior to June 1, 1970 must not equal or exceed:

   i. An average of 40 percent opacity through December 31, 2019, with the exception that visible emissions may equal or exceed an average of 40 percent opacity for up to two independent six-minute blocks in any hour, as long as the average opacity during each of these two six-minute blocks is less than 55 percent.

   ii. An average of 20 percent opacity on or after January 1, 2020, with one or more of the following exceptions:

      - Visible emissions may equal or exceed an average of 20 percent opacity for up to two independent six-minute blocks in any hour, as long as the average opacity during each of these two six-minute blocks is less than 40 percent;

- Visible emissions may equal or exceed an average of 20 percent opacity but may not equal or exceed 40 percent opacity, as the average of all six-minute blocks during grate cleaning operations provided the grate cleaning is performed in accordance with a grate cleaning plan approved by DEQ; or
- DEQ may approve a boiler specific limit greater than an average of 20 percent opacity, but not to equal or exceed an average of 40 percent opacity, based on the opacity measured during a source test that demonstrates compliance with 340-228-0210(2)(d) as provided in OAR 340-208-0110(5)(b)(C).

d. Visible emissions from wood-fired boilers installed, constructed, or modified after June 1, 1970 but before April 16, 2015, must not equal or exceed an average of 20 percent opacity with the exception that visible emissions may equal or exceed an average of 20 percent opacity for up to two independent six-minute blocks in any hour, as long as the average opacity during each of these two six-minute blocks is less than 40 percent.

e. Visible emissions from wood-fired boilers installed, constructed, or modified after April 16, 2015, must not equal or exceed an average of 20 percent opacity.

f. The visible emissions standards in this condition are based upon a six-minute block average of 24 consecutive observations recorded at 15-second intervals as specified in OAR 340-208-0110(2). Six-minute block averages are measured by EPA Method 9.

g. The visible emissions standards in this condition do not apply to fugitive emissions from the source.

h. 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 - General

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. 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.

e. Particulate matter emissions from any air contaminant source, other than fuel burning equipment, installed, constructed, or modified before June 1, 1970, must not exceed:

i. 0.10 grains per dry standard cubic foot if 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; or

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, or if there are no representative compliance source test results:

- 0.24 grains per dry standard cubic foot on or before December 31, 2019; and
- 0.15 grains per dry standard cubic foot on or after January 1, 2020;

iii. For equipment or mode of operation used less than 876 hours per calendar year:

- 0.24 grains per dry standard cubic foot from April 16, 2015 through December 31, 2019; and
- 0.20 grains per dry standard cubic foot on or after January 1, 2020.

f. Particulate matter emissions from any air contaminant source, other than 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 if 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; or

ii. 0.14 grains per dry standard cubic foot 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, or if there are no representative compliance source test results.

g. Particulate matter emissions from any air contaminant source, other than fuel burning equipment, installed, constructed, or modified on or after April 16, 2015, must not exceed 0.10 grains per dry standard cubic foot.

h. Representative compliance source test results are data that was obtained:

i. Between April 16, 2005 and April 16, 2015; and

ii. When the emission unit and pollution control device were operating based on the current configuration.

i. The combined particulate matter emissions from all veneer and plywood mill sources within the plant site, including, but not limited to, sanding machines, saws, presses, barkers, hogs, chippers, and other material size reduction equipment, process or space ventilation systems, and truck loading and unloading facilities, must not exceed a plant specific average hourly emission rate (lbs/hr) determined by multiplying the plant production capacity by one pound per 1,000 square feet on a 3/8" basis of finished product for a typical operating shift divided by the number of hours in the operating shift. Excluded from this standard are veneer dryers, fuel burning equipment, and refuse burning equipment.

j. In all areas of the state, except the Medford-Ashland AQMA and Grants Pass UGA, particulate emissions from veneer dryers must not exceed:

i. 0.75 lb/1000 square feet (MSF) on a 3/8" basis for direct wood-fired dryers when using fuel with less than or equal to 20% moisture;

ii. 1.50 lb/MSF on a 3/8" basis for direct wood-fired dryers when using fuel with greater than 20% moisture; or

iii. 0.40 lb/1000 pounds of steam generated in boilers that exhaust combustion gases to the veneer dryer;

iv. Exhaust gases from fuel-burning equipment vented to the veneer dryer are exempt from Conditions 2.2a, 2.2b and 2.2c.

k. In the Medford-Ashland AQMA and Grants Pass UGA, particulate emissions from veneer dryers must not exceed:

i. 0.30 lb/MSF on a 3/8" basis for direct natural gas or propane-fired veneer dryers;

ii. 0.30 lb/MSF on a 3/8" basis for steam heated veneer dryers;

iii. 0.40 lb/1000 square feet on a 3/8" basis for direct wood-fired dryers when using fuel with less than or equal to 20% moisture;

iv. 0.45 lb/MSF on a 3/8" basis for direct wood-fired dryers when using fuel with greater than 20% moisture;

v. 0.20 lb/1000 pounds of steam generated in boilers that exhaust combustion gases to the veneer dryer;

vi. Exhaust gases from fuel-burning equipment vented to the veneer dryer are exempt from Conditions 2.2a, 2.2b and 2.2c.

2.3 Fugitive Emissions The permittee must comply with the following, as necessary:

a. The permittee must take 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, such as but not limited to:

i. Controlling vehicle speeds on unpaved roadways;

ii. Application of water or other suitable chemicals on unpaved roads, material stockpiles, and other surfaces which can create airborne dusts;

iii. 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;

iv. Covering, at all times when in motion, open bodied trucks transporting materials likely to become airborne;

v. The prompt removal from paved streets of earth or other material (track-out) 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.

2.7 Veneer Dryers

a. No person shall willfully cause or permit the installation or use of any means, such as dilution, which, without resulting in a reduction in the total amount of air contaminants emitted, conceals an emission which would otherwise violate this rule;

b. Where effective measures are not taken to minimize fugitive emissions, DEQ may require that the equipment or structures in which processing handling, and storage are done, be tightly closed, modified, or operated in such a way that air contaminants are minimized, controlled, or removed before discharge to the open air;

c. DEQ may require more restrictive emission limits than provided in Condition 2.2j for an individual plant upon a finding by the Environmental Quality Commission that the individual plant is located in or is proposed to be located in the Medford-Ashland Air Quality Maintenance Area or the Grants Pass Urban Growth Area. The more restrictive emission limits may be established on the basis of allowable emissions expressed in opacity, pounds per hour, or total maximum daily emissions to the atmosphere, or a combination thereof.

3.0 OPERATION AND MAINTENANCE REQUIREMENTS

3.1	**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.
3.2	**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.
3.3	**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.
3.4	**Veneer Dryers**	Each veneer dryer and associated pollution control equipment must be maintained and operated at full efficiency and effectiveness so that the emissions of air contaminants is kept at the lowest practicable levels.

4.0 PLANT SITE EMISSION LIMITS

4.1 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_2e)	74,000	tons per year
Single HAP	9	tons per year
Combined HAPs	24	tons per year

4.2 PM_{10} PSEL for Medford-Ashland AQMA

For sources operating in the Medford-Ashland AQMA, plant site emissions of PM_{10} must not exceed the following:

Pollutant	Limit	Units
PM_{10}	4.5	tons per year
	49	pounds per day

4.3 Annual Period

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

5.0 COMPLIANCE DEMONSTRATION

5.1 PSEL Compliance Monitoring for PM, PM_{10}, SO_2, NO_x, CO, VOC and HAP

Compliance with the PSEL is determined for each 12-consecutive calendar month period based on the following calculation for each pollutant for all processes other than surface coating operations:

E = Σ(EF x F) / (2000 lb/ton)

where,

E = pollutant emissions (tons/yr);

Σ = symbol representing "summation of";

EF = pollutant emission factor (see Condition 5.3);

F = fuel combustion or material throughput (see Condition 6.1e)

5.2 VOC and HAP PSEL Compliance Monitoring for Surface Coating Operations

Compliance with the VOC or HAP PSEL is determined for each 12-consecutive calendar month period based on the following calculation plus the emissions calculated in Condition 5.1:

$E_{VOC\ or\ HAP}$ = $[\Sigma(C_X * D_X * K_X) - W]$ x 1 ton/2000 lb.

where,

$E_{VOC\ or\ HAP}$ = VOC or HAP emissions (tons/yr);

Σ = symbol representing "summation of";

C = Material usage for the period in gallons;

D = Material density in pounds per gallon; if K is in units of lb/lb, otherwise D = 1.

K = VOC or HAP content of the material (lb/lb);

X = Subscript X represents a specific material;

W = Weight of VOC or HAP shipped offsite (lbs).

5.3 Emission Factors

The permittee must use the default emission factors provided in Condition 13.0 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.

5.4 Medford/Ashland AQMA

If the source is located in the Medford/Ashland AQMA, the permittee must also maintain daily records and calculate the daily maximum emissions for the reporting period.

5.5 Veneer Dryers

a. DEQ may require any veneer dryer facility to establish an effective program for monitoring the visible air contaminant emissions from each veneer dryer emission point.

b. The program shall be subject to review and approval by DEQ and must consist of a specified minimum frequency for performing visual opacity determinations on each veneer dryer emission point and a specified period during which all records shall be maintained at the mill site for inspection by authorized representatives of DEQ.

c. All data obtained must be recorded on copies of a "Veneer Dryer Visible Emissions Monitoring Form" which shall be provided by DEQ or on an alternative form which is approved by DEQ.

6.0 RECORDKEEPING REQUIREMENTS

6.1 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 3.3;

b. Sulfur content of fuel oil burned in the boiler;

c. Sulfur content and analysis of used oil, as required by Condition 2.6b;

d. Records for the NSPS and NESHAP boiler(s), as required by this permit; and

e. Daily (Medford/Ashland AQMA only), monthly and annual operating parameters as shown in the table below:

Emissions Unit	Process Parameter	Units
Natural gas-fired boilers or heaters	fuel combusted	cubic feet (ft^3)
Propane, butane, or oil-fired boilers or heaters	fuel combusted	gallons

Wood-fired boilers	steam production	pounds of steam
Cyclones	material throughput by type of material	bone dry ton (BDT)
Kiln	material throughput	thousand board feet (MBF)
Veneer Dryer	material throughput	thousand square feet (MSF)
Surface Coating VOCs and HAPs	material usage	gallons or pounds
	VOC content	pounds per gallon or weight %
	HAP content (single and combined)	pounds per gallon or weight %

6.2 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.

6.3 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.

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

7.0 REPORTING REQUIREMENTS

7.1 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 8.3.

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.

7.2 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.

7.3 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. Annual emissions as calculated according to Conditions 5.1 and 5.2, including the supporting process parameter and emission factor information.

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.

7.4 Greenhouse Gas Registration and Reporting

If the calendar year emission rate of greenhouse gases (CO_2e) 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.

7.5 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.

7.6 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.

7.7 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:

a. Constructing or installing any new source of air contaminant emissions, including air pollution control equipment;

b. Modifying or altering an existing source that may significantly affect the emission of air contaminants;

c. Making any physical change which increases emissions;

d. Changing the method of operation, the process, or the fuel use, or increasing the normal hours of operation that result in increased emissions.

7.8 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 8.2.

8.0 ADMINISTRATIVE REQUIREMENTS

8.1 Reassignment to the General Permit

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.

a. 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.

b. 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.

c. If a complete application for reassignment to the general permit 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.

8.2 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 SE Salem, OR 97302 Telephone: (503) 378-8240
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

8.3 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 SE 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
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

9.0 FEES

9.1 Annual Compliance Fee The Annual Compliance Determination Fee specified in OAR 340-216-8020, Table 2, Part 2c for a Class Three 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.

9.2	**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.
9.3	**Where to Submit Fees**	Fees must be submitted to: Department of Environmental Quality Accounting / Revenue 700 NE Multnomah Street, Suite 600 Portland, Oregon 97232

10.0 GENERAL CONDITIONS AND DISCLAIMERS

10.1	**Other Regulations**	In addition to the specific requirements listed in this permit, the permittee must comply with all other legal requirements enforceable by DEQ.
10.2	**Conflicting Conditions**	In any instance in which there is an apparent conflict relative to conditions in this permit, the most stringent conditions apply.
10.3	**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.
10.4	**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.
10.5	**Permit Availability**	The permittee must have a copy of the permit available at the facility at all times.
10.6	**Open Burning**	The permittee must not conduct any open burning except as allowed by OAR 340 Division 264.
10.7	**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.

10.8	**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.
10.9	**Termination, Revocation, or Modification**	DEQ may modify or revoke this permit pursuant to OAR 340-216-0060(3) and (4), and 340-216-0082.

11.0 NEW SOURCE PERFORMANCE STANDARDS

11.1	**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.
11.2	**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.
11.3	**NSPS Visible Emissions Limit**	a.	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.
		b.	The opacity standard applies at all times except during periods of startup, shutdown or malfunction.

11.4 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.

c. 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.

d. 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).

e. If not required to use a COMS due to Condition 11.4b, the permittee must conduct a performance test using EPA Method 9 and the procedures in 40 CFR 60.11 to demonstrate compliance with Condition 11.3 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.

f. The permittee must conduct subsequent Method 9 performance tests using the procedures in Condition 11.4e 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.

11.5 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 11.5a, 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% sulfur by weight or a mixture of 0.50% 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 SO_2 emissions is not subject to the PM limit in Condition 11.5a or 11.5b.

11.6 NSPS Particulate Matter Emission Testing

For each boiler subject to the PM and/or opacity standards under Conditions 11.3 and/or 11.5, 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 DEQ, to determine compliance with the standards, except as specified in Condition 11.4.

a. The permittee must submit to DEQ the performance test data from the initial and any subsequent performance tests; and

b. 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.

11.7 NSPS Sulfur Limits

The sulfur content of fuel oil burned in the boiler must not exceed 0.5% by weight.

11.8 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 11.8c, 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.

11.9 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 11.9d, 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.

11.10 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 11.9d 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.

11.11 Construction or Modification

In addition to the Notice of Intent to Construct (NC) requirement in Condition 7.7, 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

11.12 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

12.0 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

12.1 NESHAP Applicability

a. The NESHAP applies to industrial, commercial, or institutional oil and biomass-fired boilers.

b. The NESHAP does not apply to gas-fired 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.

12.2 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. For new or reconstructed biomass-fired boilers, that meet the applicability criteria at the time construction commenced, with heat input capacities between 10 and 30 MMBtu/hr or greater, and that are not considered seasonal or limited-use boilers, the permittee must achieve less than or equal to 0.070 lbs/ MMBtu of heat input, except during periods of startup and shutdown.

c. The permittee must demonstrate initial compliance with the emission limit specified in Condition 12.2 by conducting a performance (stack) test according to 40 CFR 63.11212 and Table 2 in Appendix A to this permit.

12.3 NESHAP Work Practice Standards

a. For new or reconstructed biomass-fired or 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 biomass-fired boilers or 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 12.7. 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 5 MMBtu/hr, or biomass and 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 12.7. 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.

12.4 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.

12.5 NESHAP Initial Compliance Requirements

a. For any existing affected boiler, the permittee must demonstrate compliance with the NESHAP upon assignment to this permit, including meeting the requirement to perform an energy assessment, if applicable.

b. For any existing affected boilers that have not operated on biomass or liquid fuel since March 21, 2011, the permittee must complete the initial performance tune-up, if subject to the tune-up requirements by following the procedures described in Condition 12.7, no later than 30 days after the re-start of the affected boiler on biomass or liquid fuel.

c. For any new or reconstructed affected boiler, the permittee must demonstrate compliance with the NESHAP within 180 days of startup.

d. For new or reconstructed affected boilers that are subject to an emission limit in Condition 12.2, the permittee must demonstrate initial compliance with the emission limit no later than assignment to this permit or within 180 days after startup of the boiler, whichever is later, according to 40 CFR 63.7(a)(2)(ix).

e. 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 12.2 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 12.2 and must demonstrate compliance with the PM emission limit no later than March 12, 2020.

f. 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 12.2 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.

g. 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.

h. For affected boilers that switch fuels or make a physical change to the boiler that results in the applicability of a different subcategory within 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 12.13.

12.6 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 12.6b through 12.6i. 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 performance test for PM must be conducted by September 14, 2021.

c. 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.

d. 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.

e. 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 12.6a.

f. 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 each such performance test must be conducted no more than 61 months after the previous performance test.

g. 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.

h. 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 12.6a.

i. For existing affected boilers that have not operated on 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 biomass or liquid fuel.

12.7 NESHAP Tune-up Requirements

The permittee must conduct a performance tune-up for each biomass and 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 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.

g. A description of any corrective actions taken as a part of the tune-up of the boiler.

h. 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.

i. 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.

12.8 NESHAP Monitoring, Installation, Operation and Maintenance Requirements

a. If using a control device to comply with the emission limits specified in Condition 12.2, the permittee must maintain each operating limit in Table 1 in Appendix A to this permit that applies to the boiler as specified in Table 4 in Appendix A to this permit. If using a control device not covered in Table 1 in Appendix A 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 Conditions12.8e, 12.8f and 12.8g, as applicable. This requirement also applies if petitioning to 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 12.8b:

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 12.11. 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.

12.9 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 12.2 and Table 1 in Appendix A to this permit according to the following methods:

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 12.2 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 12.11.

12.10 NESHAP Notifications

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 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 EPA 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.

vii. 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.

12.11 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 12.11c. 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 12.7 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.

12.12 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 12.2, 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 boiler that meets the requirements of Condition 12.5e and 12.5f, 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.

vii. Records of the occurrence and duration of each malfunction of the boiler, or of the associated air pollution control and monitoring equipment.

viii. Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in Condition 12.4, including corrective actions to restore the malfunctioning boiler, air pollution control, or monitoring equipment to its normal or usual manner of operation.

b. The permittee must keep the records of all inspection and monitoring data required by Condition 12.8d and 12.8e, 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).

c. 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.

12.13 NESHAP Fuel Switch or Physical Change Notification

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:

a. 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.

b. The date upon which the fuel switch, physical change, or permit limit occurred.

13.0 EMISSION FACTORS

This section contains emission factors for both criteria pollutants and hazardous air pollutants (HAPs). Because many HAP emission factors remain under development, they represent the best available data at the time of permit renewal. The use of the following HAP emission factors does not guarantee that facilities will be in compliance with federal requirements for major sources of HAPs. Facilities should use the most reliable emission factors as they become available in the future, or provide emission source test results that demonstrate actual emissions for their specific emission unit.

13.1 Emission Factors (EF) for Boilers

a. PM, PM_{10}, $PM_{2.5}$, SO_2, NO_X, CO and VOC

Fuel type	Boiler type or controls	EF units	PM	PM_{10}	$PM_{2.5}$	SO_2	NO_X	CO	VOC
Natural Gas	Uncontrolled	lb/MMcf	2.5	2.5	2.5	1.7	100	84	5.5
	"Low NO_X" burners	lb/MMcf	2.5	2.5	2.5	1.7	50	84	5.5
	Flue gas recirculation	lb/MMcf	2.5	2.5	2.5	1.7	32	84	5.5
Propane	All	lb/Mgal	0.6	0.6	0.6	0.10S[(1)]	19	3.2	0.5
Butane	All	lb/Mgal	0.6	0.6	0.6	0.09S[(1)]	21	3.6	0.6

Fuel type	Boiler type or controls	EF units	PM	PM_{10}	$PM_{2.5}$	SO_2	NO_X	CO	VOC
#1 distillate oil	All	lb/Mgal	3.3	2.3	1.6	42.6(1)	18	5	0.2(2)
#2 distillate oil	All	lb/Mgal	3.3	2.3	1.6	71(1)	20	5	0.2(2)
#4 residual oil	All	lb/Mgal	8.5	7.5	5.4	263(1)	20	5	0.2(2)
#5 residual oil	All	lb/Mgal	11.5	10.1	7.1	275(1)	55	5	0.28(2)
#6 residual oil	All	lb/Mgal	20.8	18.2	12.4	275	55	5	0.28(2)
wood	Dutch Oven	lb/Mlbs steam	0.4	0.2	0.2	0.014	0.31	3.0	0.13
wood	Spreader-Stoker	lb/Mlbs steam	0.4	0.2	0.2	0.014	0.31	2.0	0.13
wood	Fuel Cell	lb/Mlbs steam	0.4	0.2	0.2	0.014	0.31	1.0	0.13

(1) The 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 x 0.3 = 42.6 lb/1000 gallons of oil burned.

(2) VOC reported as non-methane total organic carbon (NMTOC).

b. HAPS

Fuel type	EF units	Acrolein	Benzene	Formaldehyde	HCl	Naphthalene	Styrene	Toluene
Natural Gas	lb/MMcf		0.0021	0.075				0.0034
#1 Distillate Oil			0.00275	0.061		0.00033		
#2 Distillate Oil			0.00275	0.061		0.00033		
#4 residual oil	lb/Mgal		0.000214	0.033		0.00113		0.0062
#5 residual oil	lb/Mgal		0.000214	0.033		0.00113		0.0062
#6 residual oil	lb/Mgal		0.000214	0.033		0.00113		0.0062
Wood	lbs/Mlbs Steam	0.0060	0.0063	0.0066	0.029	0.000146	0.0014	0.00138

Fuel type	EF units	Antimony	Arsenic	Chromium	Cobalt	Lead	Manganese	Nickel
Natural Gas	lb/MMcf		0.00020		0.000084	0.0005	0.00038	0.0021
#1 distillate oil	lb/Mgals		0.00056	0.00042		0.0013	0.00083	0.00042
#2 distillate oil	lb/Mgals		0.00056	0.00042		0.0013	0.00083	0.00042
#4 residual oil	lb/Mgals	0.0053	0.0013		0.0060	0.0015	0.0030	0.0845
#5 residual oil	lb/Mgals	0.0053	0.0013		0.0060	0.0015	0.0030	0.0845
#6 residual oil	lb/Mgals	0.0053	0.0013		0.0060	0.0015	0.0030	0.0845
Wood	lbs/Mgals Steam	0.000012	0.000033		0.0000098	0.000072	0.0024	0.00005

13.2 Emission Factors for Cyclones and Target Boxes

Process Equipment	Type	Description	Units	PM (lb/BDT)	PM_{10} (lb/BDT)	$PM_{2.5}$ (lb/BDT)
Cyclone	Medium Efficiency	Dry & Green Chips, Shavings, Hogged Fuel/Bark, Green Sawdust	Bone Dry Tons (BDT)	0.5	0.43	0.25
	High Efficiency			0.2	0.19	0.16
	Baghouse Control			0.001	0.001	0.001
	Medium Efficiency	Sanderdust	Bone Dry Tons (BDT)	NA	NA	NA
	High Efficiency			2.0	1.9	0.16
	Baghouse Control			0.04	0.04	0.04
Target Box	Medium Efficiency	Sanderdust	Bone Dry Tons (BDT)	0.1	0.085	0.05

13.3 Emission Factors for Steam and Electric Heated Kilns ($\leq$ 200 °F) (lb/1000 board feet)[1]

Wood species	PM/PM_{10}	VOC	Methanol	Formaldehyde	Acetaldehyde
Ponderosa Pine	0.02	1.96	0.055	0.0028	0.042
Lodgepole Pine	0.02	1.38	0.073	0.000	0.012
Douglas Fir	0.02	0.77	0.039	0.0013	0.051
White Fir	0.05	0.59	0.122	0.0028	0.055
Hemlock	0.05	0.38	0.081	0.0013	0.120

(1) Use source specific data, if available

13.4 Emission Factors for Steam and Electric Heated Kilns (> 200 °F) (lb/1000 board feet)[1]

Wood species	PM/PM_{10}	VOC	Methanol	Formaldehyde	Acetaldehyde
Ponderosa Pine	0.02	3.80	0.144	0.0092	0.028
Lodgepole Pine	0.02	1.39	0.060	0.0040	0.028
Douglas Fir	0.02	1.62	0.117	0.0043	0.040
White Fir	0.05	0.99	0.420	0.016	0.055
Hemlock	0.05	0.53	0.184	0.0039	0.084

(1) Use source specific data, if available

13.5 Emission Factors for Veneer Dryers (lb/1000 square feet, 3/8" basis)

a. PM/PM_{10}, NO_x, and CO:

Process Equipment	Description	$PM/PM_{10}PM_{2.5}$	NO_X	CO
Veneer Dryer - Gas heat	Douglas Fir (uncontrolled)	0.52	0.12	0.02
	Douglas Fir (Burley or 45% control)	0.29		
	Hemlock, White Fir (uncontrolled)	0.15		
	Hemlock, White Fir (Burley or 45% control)	0.10		
Veneer Dryer - Steam heat	Douglas Fir (uncontrolled)	1.01	None	
	Douglas Fir (Burley or 45% control)	0.56		
	Hemlock, White Fir (uncontrolled)	0.25		
	Hemlock, White Fir (Burley or 45% control)	0.15		

State of Oregon Department of Environmental Quality

b. VOC and Hazardous Air Pollutants: These factors are based on recent studies performed on **softwoods** by NCASI. EPA incorporated NCASI's data into AP-42, but did not distinguish between southern and northwest softwood species. Therefore, the highest average test result is included in this permit as a conservative estimate of emissions. The VOC emission factors have been adjusted to an as propane basis by the multiplying the carbon basis by a factor of 44/36. All emission factors are in units of pounds per 1000 square feet on a 3/8" basis (lb/MSF) for uncontrolled emissions.

Dryer type/activity	**Pollutant**	**Steam heated**	**Direct Wood-Fired**	**Direct Natural Gas-Fired**
Veneer Dryers	VOC	1.8	1.1	2.5
	Acetaldehyde	0.017	ND(1)	0.062
	Acrolein	0.0013	ND	0.009
	Formaldehyde	0.014	0.045	0.064
	Methanol	0.039	ND	0.036
	Phenol	0.0034	ND	0.006
	Propionaldehyde	0.0024	ND	0.0016
	Benzene	0.00059		0.0057
	Toluene	0.0011	ND	0.0074
	m, p-xylene	0.00075	ND	0.0039
Cooling Section	VOC	0.054	ND(1)	0.044
	Acetaldehyde	0.0046	ND	0.0034
	Acrolein	BDL	ND	BDL
	Formaldehyde	0.0013	ND	0.0015
	Methanol	0.010	ND	0.0057
	Phenol	0.0062	ND	0.010
	Propionaldehyde	BDL	ND	0.002
Fugitives	VOC	0.06	ND	0.046
	Acetaldehyde	0.005	ND	0.003
	Formaldehyde	0.001	ND	0.002
	Methanol	0.01	ND	0.006
	Phenol	0.006	ND	0.01

(1) ND = No Data

13.6 Plywood Presses (lb/MSF[1]) using Phenol Formaldehyde Resin

Pollutant	Softwood Emission Factor
VOC	0.25
Acetaldehyde	0.0042
Formaldehyde	0.0019
Methanol	0.14
Phenol	0.0014

(1) MSF = 1000 ft^2

13.7 Miscellaneous Plywood Activities

Pollutant	**I-J CC**[1] (lbs/MLF)	**I-J Saw**[2] (lbs/MLF)	**Log Vats** (lbs/MSF 3/8")	**Trim Chip** (lbs/MSF 3/8")	**Sander** (lbs/MSF)	**Skin Saw** (lbs/MSF)
VOC	0.0035	0.11	ND[3]	0.068	0.18	0.086
Acetaldehyde	BDL[4]	BDL	0.0047	BDL	0.0028	0.0009
Formaldehyde	0.0002	BDL	BDL	BDL	0.002	0.0003
Methanol	0.0006	0.016	0.007	0.008	0.012	0.012

(1) I-Joist Conditioning Chamber
(2) I-Joist Saw
(3) ND=No Data
(4) BDL=Below Detection Limits

13.8 Emission Factors for Surface Coating Operations

Consult manufacturer or Safety Data Sheet for required information needed to calculate emissions.

14.0 ABBREVIATIONS, ACRONYMS, AND DEFINITIONS

ACDP	Air Contaminant Discharge Permit
ASTM	American Society for Testing and Materials
AQMA	Air Quality Maintenance Area
Btu	British thermal unit
calendar year	The 12-month period beginning January 1st and ending December 31st
CFR	Code of Federal Regulations
CMS	Continuous monitoring system
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
COMS	Continuous opacity monitoring system
CPMS	Continuous parameter monitoring system
DEQ	Oregon Department of Environmental Quality
dscf	dry standard cubic foot
EPA	US Environmental Protection Agency
FCAA	Federal Clean Air Act
gal	gallon(s)
GHGs	Greenhouse gasses in CO_2 equivalent
gr/dscf	grains per dry standard cubic foot
HAP	Hazardous Air Pollutant as defined by OAR 340-244-0040
ID	identification number
I&M	inspection and maintenance
lb	pound(s)
MBF	1000 board feet
Mgal	1000 gallons
Mlbs	1000 pounds
MLF	1000 linear feet
MMBtu	million British thermal units
MMcf	Million cubic
MSF	1000 square feet
NA	not applicable
NO_X	nitrogen oxides
NSR	New Source Review
O_2	oxygen
OAR	Oregon Administrative Rules
ORS	Oregon Revised Statutes
O&M	operation and maintenance
Pb	lead
PCD	pollution control device
PM	particulate matter
PM_{10}	particulate matter less than 10 microns in size
$PM_{2.5}$	particulate matter less than 2.5 microns in size
ppm	part per million
PSD	Prevention of Significant Deterioration
PSEL	Plant Site Emission Limit
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
scf	standard cubic foot
SER	Significant Emission Rate
SIC	Standard Industrial Code
SIP	State Implementation Plan
SO_2	sulfur dioxide
Special Control Area	as defined in OAR 340-204-0070
VE	visible emissions
VOC	volatile organic compound
year	A period consisting of any 12 consecutive calendar months

State of Oregon Department of Environmental Quality

APPENDIX A: 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 12.8g 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.	Method 1 in Appendix A-1 to 40 CFR Part 60.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in Appendix A-2 to 40 CFR Part 60.
	c. Determine oxygen and carbon dioxide concentration of the stack gas.	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.

State of Oregon Department of Environmental Quality

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	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. 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.
	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	i. The permittee must collect secondary electric power data every 15 minutes during the entire period of the performance stack tests. ii. Determine the average total secondary electric power for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.
2. 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)	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. ii. Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test. 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.

State of Oregon Department of Environmental Quality

Table 4 - Demonstrating Continuous Compliance

If the permittee must meet the following operating limits...	The permittee must demonstrate continuous compliance by...
1. Opacity.	a. Collecting the opacity monitoring system data according to Conditions 12.8d and 12.8f; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to Condition 12.8g and operating the fabric filter such that the requirements in Condition iii are met.
3. Wet Scrubber Pressure Drop and Liquid Flow-rate	a. Collecting the pressure drop and liquid flow rate monitoring system data according to Condition 12.8; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average pressure drop and liquid flow rate at or above the minimum pressure drop and minimum liquid flow rate according to 40 CFR 63.11211.
4. Dry Scrubber Sorbent or Activated Carbon Injection Rate	a. Collecting the sorbent or activated carbon injection rate monitoring system data for the dry scrubber according to Condition 12.8; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average sorbent or activated carbon injection rate at or above the minimum sorbent or activated carbon injection rate according to 40 CFR 63.11211.
5. Electrostatic Precipitator Total Secondary Electric Power	a. Collecting the total secondary electric power monitoring system data for the electrostatic precipitator according to Condition 12.8; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average total secondary electric power at or above the minimum secondary electric power according to 40 CFR 63.11211.
6. Boiler operating load	a. Collecting operating load data (fuel feed rate or steam generation data) every 15 minutes; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average at or below the operating limit established during the performance test according to 40 CFR 63.11212(c) and Table 3.