United States Environmental Protection Agency
Region 10, Office of Air, Waste and Toxics
AWT-150
1200 Sixth Avenue, Suite 900
Seattle, Washington 98101-3140

Permit Number: R10T5010100
Issued: September 30, 2014
Effective: October 31, 2014
Expiration: September 30, 2019
Replaces: R10T5010001
AFS Plant I.D. Number: 41-065-00034

Title V Air Quality Operating Permit
Permit Renewal No. 1

In accordance with the provisions of Title V of the Clean Air Act (42 U.S.C. 7401 *et seq.*), 40 CFR Part 71 and other applicable rules and regulations,

Warm Springs Forest Products Industries

is authorized to operate air emission units and to conduct other air pollutant emitting activities in accordance with the conditions listed in this permit. This source is authorized to operate in the following location:

Location: Warm Springs Reservation
Highway 26
Warm Springs, Oregon
Latitude: 44.765 N Longitude: 121.236 W

Responsible Official: John Katchia Jr., Chief Executive Officer
Warm Springs Forest Products Industries
Highway 26
P.O. Box 810
Warm Springs, Oregon 97761-0810
Phone: 541.553.1131, Fax: 541.553.1561

Company Contact: Don Baker, Energy Manager
Warm Springs Forest Products Industries
Highway 26
P.O. Box 810
Warm Springs, Oregon 97761-0810
Phone: 541.553.2109, Fax: 541.553.1561
Email: dbaker@wsfpi.com

The United States Environmental Protection Agency (EPA) has also developed a statement of basis that describes the bases for conditions contained in this permit.

Donald A. Dossett, P.E., Manager
Air Permits and Diesel Unit
Office of Air, Waste and Toxics
U.S. EPA, Region 10

9/30/2014
Date

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1. Source Information and Emission Units

The Warm Springs Forest Products Industries (WSFPI or permittee) facility is a sawmill that produces dry dimensional lumber from logs. The emission units are listed in Table 1.

Table 1: Emission Units (EU) & Control Devices

EU ID	Emission Unit Description	Control Device[1]
PH5	*Biomass Boiler*. Wellons Model No. NB234. Serial No. B2329-0503. Two-cell pile-burning design with automatic rotating grates and overfeed fuel delivery. Combustion air introduced below and above grates. Oxygen trim system. Heat input capacity 131 million Btu/hr (MMBtu/hr). Maximum steam production 80,000 lb/hr at 250 psig and 750ºF. Generates only superheated steam. Supplies steam to kilns (via desuperheater), to non-extractive steam turbine electric generating units and to Warm Springs Composite Products (via desuperheater). Permit authorizing construction issued May 4, 2005. Startup December 27, 2005.	1. Wellons multiclone. Model No. W144. Serial No. B2329-1226. 2. Wellons electrostatic precipitator (ESP). Model No. 2W-092-1422. Serial No. B2320-2425. Part of original boiler installation.
KLN-N	*Nardi Lumber Drying Kilns*. Indirectly heated. Five single-track Nardi kilns (No.'s 1-5) installed 1997. Annual capacity of approximately 77 million board feet (mmbf) with each track contributing 15.37 mmbf.	None
KLN-W	*Wellons Lumber Drying Kilns*. Indirectly heated. Two double-track Wellons kilns (No's 6a – 7b) installed 2000. Annual capacity of approximately 61 mmbf with each track contributing 15.37 mmbf.	None
CYC	*Wood Residue Cyclones*. Six cyclones (CYC1 through CYC6) employed to capture pneumatically conveyed wood residue and deposit into storage bins for later sale and distribution off-site or consumption by boiler on-site. The six capture devices are process equipment and not air pollution control devices (APCD).[2]	None
MNFA	*Miscellaneous Non-Fugitive Activities.* Activities occurring inside a building that generate wood residue that is not pneumatically conveyed to a product recovery device.	Inside building
MFA	*Miscellaneous Fugitive Activities.* Activities occurring outside a building or storage structure that generate, transport or store wood residue.	None
PT	*Plant traffic*. Fugitive emissions including forklifts and log trucks (paved and unpaved roads).	Watering

[1] The multiclone and electrostatic precipitator (ESP) are required to be used by this permit.

[2] See November 27, 1995 letter from EPA's David Solomon to Intel's Timothy J. Mohin. Although CYC is considered process equipment (as opposed to APCD) for the purpose of calculating potential emissions, CYC is not considered a "process source" in the context of the Federal Air Rules for

Reservations (FARR) as CYC does not cause a change in material by either chemical or physical means. See definition of "process source" at 40 CFR § 49.123.

2. Standard Terms and Conditions

2.1. Terms not otherwise defined in this permit have the meaning assigned to them in the referenced regulations. The language of the cited regulation takes precedence over paraphrasing except the text of terms specified pursuant to any of the following sections is directly enforceable: section 304(f)(4) of the Federal Clean Air Act (CAA), 40 CFR §§ 71.6(a)(3)(i)(B) and (C), 71.6(a)(3)(ii), and 71.6(b), or any other term specifically identified as directly enforceable.

Compliance with the Permit

2.2. The permittee must comply with all conditions of this Part 71 permit. All terms and conditions of this permit are enforceable by EPA and citizens under the Clean Air Act. Any permit noncompliance constitutes a violation of the Clean Air Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. [40 CFR § 71.6(a)(6)(i)]

2.3. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. [40 CFR § 71.6(a)(6)(ii)]

Permit Shield

2.4. Compliance with the terms and conditions of this permit shall be deemed compliance with the applicable requirements specifically listed in this permit as of the date of permit issuance. [40 CFR § 71.6(f)(1)]

2.5. Nothing in this permit shall alter or affect the following:

2.5.1. The provisions of section 303 of the Clean Air Act (emergency orders), including the authority of EPA under that section;

2.5.2. The liability of a permittee for any violation of applicable requirements prior to or at the time of permit issuance;

2.5.3. The applicable requirements of the acid rain program, consistent with section 408(a) of the Clean Air Act; or

2.5.4. The ability of EPA to obtain information under section 114 of the Clean Air Act.

[40 CFR § 71.6(f)(3)]

Other Credible Evidence

2.6. For the purpose of submitting compliance certifications in accordance with Condition 3.49 of this permit, or establishing whether or not a person has violated or is in violation of any requirement of this permit, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.
[Section 113(a) and 113(e)(1) of the CAA, 40 CFR §§ 51.212, 52.12, 52.33, 60.11(g) and 61.12]

Emergency Provisions

2.7. In addition to any emergency or upset provision contained in any applicable requirement, the permittee may seek to establish that noncompliance with a technology-based emission limitation under this permit was due to an emergency. To do so, the permittee shall demonstrate the affirmative defense of emergency through properly signed, contemporaneous operating logs, or other relevant evidence that:

2.7.1. An emergency occurred and that the permittee can identify the cause(s) of the emergency;

2.7.2. The permitted facility was at the time being properly operated;

2.7.3. During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards, or other requirements in this permit; and

2.7.4. The permittee submitted notice of the emergency to EPA within two working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken. This notice fulfills the requirements of Condition 3.48 of this permit, concerning prompt notification of deviations.

[40 CFR §§ 71.6(g)(2), (3) and (5)]

2.8. In any enforcement proceeding, the permittee attempting to establish the occurrence of an emergency has the burden of proof. [40 CFR § 71.6(g)(4)]

2.9. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [40 CFR § 71.6(g)(1)]

Permit Actions

2.10. This permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR § 71.6(a)(6)(iii)]

2.11. The permit may be reopened by EPA and the permit revised prior to expiration under any of the circumstances described in 40 CFR § 71.7(f). [40 CFR § 71.7(f)]

Permit Expiration and Renewal

2.12. This permit shall expire on the expiration date on page one of this permit or on an earlier date if the source is issued a Part 70 or Part 71 permit by a permitting authority under an EPA approved or delegated permit program. [40 CFR § 71.6(a)(11)]

2.13. Expiration of this permit terminates the permittee's right to operate unless a timely and complete permit renewal application has been submitted at least six months, but not more than 18 months, prior to the date of expiration of this permit.

[40 CFR §§ 71.5(a)(1)(iii), 71.7(b) and 71.7(c)(1)(ii)]

2.14. If the permittee submits a timely and complete permit application for renewal, consistent with 40 CFR § 71.5(a)(2), but EPA has failed to issue or deny the renewal permit, then all the terms and

conditions of the permit, including any permit shield granted pursuant to 40 CFR § 71.6(f) shall remain in effect until the renewal permit has been issued or denied. This permit shield shall cease to apply if, subsequent to the completeness determination, the permittee fails to submit by the deadline specified in writing by EPA any additional information identified as being needed to process the application. [40 CFR §§ 71.7(c)(3) and 71.7(b)]

Off-Permit Changes

2.15. The permittee is allowed to make certain changes without a permit revision, provided that the following requirements are met:

2.15.1. Each change is not addressed or prohibited by this permit;

2.15.2. Each change meets all applicable requirements and does not violate any existing permit term or condition;

2.15.3. The changes are not changes subject to any requirement of 40 CFR Parts 72 through 78 or modifications under any provision of Title I of the Clean Air Act;

2.15.4. The permittee provides contemporaneous written notice to EPA of each change, except for changes that qualify as insignificant activities under 40 CFR § 71.5(c)(11), that describes each change, the date of the change, any change in emissions, pollutants emitted, and any applicable requirements that would apply as a result of the change;

2.15.5. The changes are not covered by a permit shield provided under 40 CFR § 71.6(f) and Conditions 2.4 and 2.5 of this permit; and

2.15.6. The permittee keeps a record describing all changes that result in emissions of any regulated air pollutant subject to any applicable requirement not otherwise regulated under this permit, and the emissions resulting from those changes.

[40 CFR §71.6(a)(12)]

Emissions Trading and Operational Flexibility

2.16. The permittee is allowed to make a limited class of changes under section 502(b)(10) of the Clean Air Act within this permitted facility that contravene the specific terms of this permit without applying for a permit revision, provided:

2.16.1. The changes do not exceed the emissions allowable under this permit (whether expressed therein as a rate of emissions or in terms of total emissions);

2.16.2. The changes are not modifications under any provision of Title I of the Clean Air Act;

2.16.3. The changes do not violate applicable requirements;

2.16.4. The changes do not contravene federally enforceable permit terms and conditions that are monitoring (including test methods), recordkeeping, reporting, or compliance certification requirements;

2.16.5. The permittee sends a notice to EPA, at least seven days in advance of any change made under this provision, that describes the change, when it will occur and any change in emissions and identifies any permit terms or conditions made inapplicable as a result of the change and the permittee attaches each notice to its copy this permit; and

2.16.6. The changes are not covered by a permit shield provided under 40 CFR § 71.6(f) and Conditions 2.4 and 2.5 of this permit.

[40 CFR § 71.6(a)(13)(i)]

2.17. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this permit. [40 CFR § 71.6(a)(8)]

Severability

2.18. The provisions of this permit are severable, and in the event of any challenge to any portion of this permit, or if any portion is held invalid, the remaining permit conditions shall remain valid and in force. [40 CFR §71.6(a)(5)]

Property Rights

2.19. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 CFR §71.6(a)(6)(iv)]

3. General Requirements

General Compliance Schedule

3.1. For applicable requirements with which the source is in compliance, the permittee will continue to comply with such requirements. [40 CFR §§ 71.6(c)(3) and 71.5(c)(8)(iii)(A)]

3.2. For applicable requirements that will become effective during the permit term, the permittee shall meet such requirements on a timely basis. [40 CFR §§ 71.6(c)(3) and 71.5(c)(8)(iii)(B)]

Inspection and Entry

3.3. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow EPA or an authorized representative to perform the following:

3.3.1. Enter upon the permittee's premises where a Part 71 source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;

3.3.2. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

3.3.3. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

3.3.4. As authorized by the Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

[40 CFR § 71.6(c)(2)]

Open Burning Restrictions

3.4. Except as exempted in 40 CFR § 49.131(c), the permittee shall not openly burn, or allow the open burning of, the following materials:

3.4.1. Garbage;

3.4.2. Dead animals or parts of dead animals;

3.4.3. Junked motor vehicles or any materials resulting from a salvage operation;

3.4.4. Tires or rubber materials or products;

3.4.5. Plastics, plastic products, or styrofoam;

3.4.6. Asphalt or composition roofing, or any other asphaltic material or product;

3.4.7. Tar, tarpaper, petroleum products, or paints;

3.4.8. Paper, paper products, or cardboard other than what is necessary to start a fire or that is generated at single-family residences or residential buildings with four or fewer dwelling units and is burned at the residential site;

3.4.9. Lumber or timbers treated with preservatives;

3.4.10. Construction debris or demolition waste;

3.4.11. Pesticides, herbicides, fertilizers, or other chemicals;

3.4.12. Insulated wire;

3.4.13. Batteries;

3.4.14. Light bulbs;

3.4.15. Materials containing mercury (e.g., thermometers);

3.4.16. Asbestos or asbestos-containing materials;

3.4.17. Pathogenic wastes;

3.4.18. Hazardous wastes; or

3.4.19. Any material other than natural vegetation that normally emits dense smoke or noxious fumes when burned.

[40 CFR §§ 49.131(c) and (d)(1)]

3.5. Open burning shall be conducted as follows:

3.5.1. All materials to be openly burned shall be kept as dry as possible through the use of a cover or dry storage;

3.5.2. Before igniting a burn, noncombustibles shall be separated from the materials to be openly burned to the greatest extent practicable;

3.5.3. Natural or artificially induced draft shall be present, including the use of blowers or air curtain incinerators where practicable;

3.5.4. To the greatest extent practicable, materials to be openly burned shall be separated from the grass or peat layer; and

3.5.5. A fire shall not be allowed to smolder.

[40 CFR § 49.131(e)(1)]

3.6. Except for exempted fires set for cultural or traditional purposes, a person shall not initiate any open burning when:

3.6.1. The Regional Administrator has declared a burn ban; or

3.6.2. An air stagnation advisory has been issued or an air pollution alert, warning or emergency has been declared by the Regional Administrator.

[40 CFR §§ 49.131(d)(2), (d)(3) and (e)(2), and 49.137(c)(4)(i)]

3.7. Except for exempted fires set for cultural or traditional purposes, any person conducting open burning when such an advisory is issued or declaration is made shall either immediately extinguish the fire, or immediately withhold additional material such that the fire burns down.
[40 CFR §§ 49.131(e)(3) and 49.137(c)(4)(ii)]

3.8. Nothing in this section exempts or excuses any person from complying with applicable laws and ordinances of local fire departments and other governmental jurisdictions.
[40 CFR § 49.131(d)(4)]

Visible Emissions Limits

3.9. Except as provided for in Conditions 3.10 and 3.11, the visible emissions from any air pollution source that emits, or could emit, particulate matter or other visible air pollutants shall not exceed 20% opacity, averaged over any consecutive six-minute period. Compliance with this emission limit is determined as follows:

3.9.1. Using EPA Reference Method 9 found in Appendix A of 40 CFR part 60; or

3.9.2. Alternatively, using a continuous opacity monitoring system that complies with Performance Specification 1 found in Appendix B of 40 CFR part 60.

[40 CFR §§ 49.124(d)(1) and (e)]

3.10. The requirements of Condition 3.9 do not apply to open burning, agricultural activities, forestry and silvicultural activities, non-commercial smoke houses, sweat houses or lodges, smudge pots, furnaces and boilers used exclusively to heat residential buildings with four or fewer dwelling units, or emissions from fuel combustion in mobile sources. [40 CFR § 49.124(c)]

3.11. Exceptions to the visible emission limit in Condition 3.9 include:

3.11.1. The visible emissions from an air pollution source may exceed the 20% opacity limit if the owner or operator of the air pollution source demonstrates to the Regional Administrator's satisfaction that the presence of uncombined water, such as steam, is the only reason for the failure of an air pollution source to meet the 20% opacity limit.

3.11.2. The visible emissions from an oil-fired boiler or solid fuel-fired boiler that continuously measures opacity with a continuous opacity monitoring system (COMS) may exceed the 20% opacity limit during start-up, soot blowing, and grate cleaning for a single period of up to 15 consecutive minutes in any eight consecutive hours, but must not exceed 60% opacity at any time.

[40 CFR §§ 49.124(d)(2) and (3)]

Fugitive Particulate Matter Requirements and Recordkeeping

3.12. Except as provided for in Condition 3.17, the permittee shall take all reasonable precautions to prevent fugitive particulate matter emissions and shall maintain and operate all pollutant-emitting activities to minimize fugitive particulate matter emissions. Reasonable precautions include, but are not limited to the following:

3.12.1. Use, where possible, of water or chemicals for control of dust in the demolition of buildings or structures, construction operations, grading of roads, or clearing of land;

3.12.2. Application of asphalt, oil (but not used oil), water, or other suitable chemicals on unpaved roads, materials stockpiles, and other surfaces that can create airborne dust;

3.12.3. Full or partial enclosure of materials stockpiles in cases where application of oil, water, or chemicals is not sufficient or appropriate to prevent particulate matter from becoming airborne;

3.12.4. Implementation of good housekeeping practices to avoid or minimize the accumulation of dusty materials that have the potential to become airborne, and the prompt cleanup of spilled or accumulated materials;

3.12.5. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials;

3.12.6. Adequate containment during sandblasting or other similar operations;

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

3.12.8. The prompt removal from paved streets of earth or other material that does or may become airborne.

[40 CFR §§ 49.126(d)(1) and (2)]

3.13. Once each calendar year, during typical operating conditions and meteorological conditions conducive to producing fugitive dust, the permittee shall survey the facility to determine the sources of fugitive particulate matter emissions. For new sources or new operations, a survey shall be conducted within 30 days after commencing operation.

3.13.1. The permittee shall record the results of the survey, including the date and time of the survey and identification of any sources of fugitive particulate matter emissions found; and

3.13.2. If sources of fugitive particulate matter emissions are present, the permittee shall determine the reasonable precautions that will be taken to prevent fugitive particulate matter emissions.

[40 CFR §§ 49.126(e)(1)(i) and (ii)]

3.14. The permittee shall prepare, and update as necessary following each survey, a written plan that specifies the reasonable precautions that will be taken and the procedures to be followed to prevent fugitive particulate matter emissions, including appropriate monitoring and recordkeeping.

3.14.1. For construction or demolition activities, a written plan shall be prepared prior to commencing construction or demolition.

[40 CFR §§ 49.126(e)(1)(iii) and (iv)]

3.15. The permittee shall implement the written plan, and maintain and operate all sources to minimize fugitive particulate matter emissions. [40 CFR §§ 49.126(e)(1)(iii) and (iv)]

3.16. Efforts to comply with this section cannot be used as a reason for not complying with other applicable laws and ordinances. [40 CFR § 49.126(e)(3)]

3.17. The requirements of Conditions 3.12 through 3.16 do not apply to open burning, agricultural activities, forestry and silvicultural activities, sweat houses or lodges, non-commercial smoke houses, or activities associated with single-family residences or residential buildings with four or fewer dwelling units. [40 CFR § 49.126(c)]

Other Work Practice Requirements and Recordkeeping

3.18. The permittee shall comply with the requirements of the Chemical Accident Prevention Provisions at 40 CFR Part 68 no later than the latest of the following dates:

3.18.1. Three years after the date on which a regulated substance, present above the threshold quantity in a process, is first listed under 40 CFR § 68.130; or

3.18.2. The date on which a regulated substance is first present above a threshold quantity in a process.

[40 CFR § 68.10]

3.19. Except as provided for motor vehicle air conditioners (MVACs) in 40 CFR Part 82, Subpart B, the permittee shall comply with the stratospheric ozone and climate protection standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F.

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

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

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

3.19.4. Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with recordkeeping requirements pursuant to 40 CFR § 82.166. ("MVAC-like appliance" is defined at 40 CFR § 82.152.)

3.19.5. Persons owning commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to 40 CFR § 82.156.

3.19.6. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR § 82.166.

[40 CFR Part 82, Subpart F]

3.20. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone-depleting substance refrigerant (or regulated substitute substance) in the MVAC, the permittee must comply with all the applicable requirements for stratospheric ozone and climate protection as specified in 40 CFR Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

[40 CFR Part 82, Subpart B]

3.21. The permittee shall comply with 40 CFR Part 61, Subpart M for asbestos removal and disposal when conducting any renovation or demolition at the facility. [40 CFR Part 61, Subpart M]

General Testing and Associated Recordkeeping and Reporting

3.22. In addition to the specific testing requirements contained in the facility and emission unit-specific sections of this permit, the permittee shall comply with the generally applicable testing requirements in Conditions 3.23 through 3.30 whenever conducting a performance test required by this permit unless specifically stated otherwise in this permit.

[40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

3.23. Test Notification. The permittee shall provide EPA at least 30 days prior notice of any performance test, except as otherwise specified in this permit, to afford EPA the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay in conducting the scheduled performance test, the permittee shall notify EPA as soon as possible of any delay in the original test date, either by providing at least seven days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with EPA by mutual agreement. [40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

3.24. Test Plan. The permittee shall submit to EPA a source test plan 30 days prior to any required testing. The source test plan shall include and address the following elements:

3.24.1. Purpose and scope of testing;

3.24.2. Source description, including a description of the operating scenarios and mode of operation during testing and including fuel sampling and analysis procedures;

3.24.3. Schedule/dates of testing;

3.24.4. Process data to be collected during the test and reported with the results, including source-specific data identified in the facility or emission unit-specific sections of this permit;

3.24.5. Sampling and analysis procedures, specifically requesting approval for any proposed alternatives to the reference test methods, and addressing minimum test length (e.g., one hour, eight hours, 24 hours, etc.) and minimum sample volume;

3.24.6. Sampling location description and compliance with the reference test methods;

3.24.7. Analysis procedures and laboratory identification;

3.24.8. Quality assurance plan;

3.24.9. Calibration procedures and frequency;

3.24.10. Sample recovery and field documentation;

3.24.11. Chain of custody procedures;

3.24.12. Quality assurance/quality control project flow chart;

3.24.13. Data processing and reporting;

3.24.14. Description of data handling and quality control procedures; and

3.24.15. Report content and timing.

[40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

3.25. Facilities for performing and observing the emission testing shall be provided that meet the requirements of 40 CFR 60.8(e) and Reference Method 1 (40 CFR Part 60, Appendix A).
[40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

3.26. Unless EPA determines in writing that other operating conditions are representative of normal operations or unless specified in the facility or emission unit-specific sections of this permit, the source shall be operated at a capacity of at least 90% but no more than 100% of maximum during all tests.

[40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

3.27. Only regular operating staff may adjust the processes or emission control devices during or within two hours prior to the start of a source test. Any operating adjustments made during a source test, that are a result of consultation during the tests with source testing personnel, equipment vendors, or consultants, may render the source test invalid. [40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

3.28. Each source test shall follow the reference test methods specified by this permit and consist of at least three valid test runs.

3.28.1. If the reference test method yields measured pollutant concentration values at an oxygen concentration other than specified in the emission standard, the permittee shall correct the measured pollutant concentration to the oxygen concentration specified in the emission standard by using the following equation:

$$PC_X = PC_M \times \frac{(20.9 - X)}{(20.9 - Y)}$$

Where: PC_X = Pollutant concentration at X percent;
PC_M = Pollutant concentration as measured;
X = The oxygen concentration specified in the standard; and
Y = The measured average volumetric oxygen concentration.

[40 CFR § 71.6(a)(3)(i)(B)]

3.28.2. Source test emission data shall be reported as the arithmetic average of all valid test runs and in the terms of any applicable emission limit, unless otherwise specified in the facility or emission unit-specific sections of this permit.

[40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

3.29. Test Records. For the duration of each test run (unless otherwise specified), the permittee shall record the following information:

3.29.1. All data which is required to be monitored during the test in the facility or emission unit-specific sections of this permit; and

3.29.2. All continuous monitoring system data which is required to be routinely monitored in the facility or emission unit-specific sections of this permit for the emission unit being tested.

[40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

3.30. Test Reports. Emission test reports shall be submitted to EPA within 60 days of completing any emission test required by this permit along with data required to be recorded in Condition 3.29 above. [40 CFR §§ 71.6(a)(3) and 71.6(c)(1)]

General Recordkeeping

3.31. Monitoring Records. The permittee shall keep records of required monitoring information that include the following:

3.31.1. The date, place, and time of sampling or measurements;

3.31.2. The date(s) analyses were performed;

3.31.3. The company or entity that performed the analyses;

3.31.4. The analytical techniques or methods used;

3.31.5. The results of such analyses; and,

3.31.6. The operating conditions as existing at the time of sampling or measurement.

[40 CFR § 71.6(a)(3)(ii)(A)]

3.32. Off-Permit Change Records. The permittee shall keep a record describing all off-permit changes allowed to be made under Condition 2.15 that result in emissions of any regulated air pollutant subject to any applicable requirement not otherwise regulated under this permit, and the emissions resulting from those changes. [40 CFR §71.6(a)(12)]

3.33. Open Burning Records. For any open burning allowed under Conditions 3.4 through 3.8, the permittee shall document the following:

3.33.1. The date that burning was initiated;

3.33.2. The duration of the burn;

3.33.3. The measures taken to comply with each provision of Condition 3.5; and

3.33.4. The measures taken to ensure that materials prohibited in Condition 3.4 were not burned.

[40 CFR § 71.6(a)(3)(i)(B)]

3.34. Fee Records. The permittee shall retain in accordance with the provisions of Condition 3.35 of this permit, all work sheets and other materials used to determine fee payments. Records shall be retained for five years following the year in which the emissions data is submitted.

[40 CFR § 71.9(i)]

3.35. Records Retention. The permittee shall retain records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

[40 CFR §§ 71.6(a)(3)(ii)(B), 49.126(e)(1)(v) and 49.130(f)(2)]

General Reporting

3.36. Additional Information. The permittee shall furnish to EPA, within a reasonable time, any information that EPA may request in writing to determine whether cause exists for modifying, revoking, and reissuing, or terminating the permit, or to determine compliance with the permit. Upon request, the permittee shall also furnish to EPA copies of records that are required to be kept pursuant to the terms of the permit, including information claimed to be confidential. Information claimed to be confidential must be accompanied by a claim of confidentiality according to the provisions of 40 CFR Part 2, Subpart B.

[40 CFR §§ 71.6(a)(6)(v) and 71.5(a)(3)]

3.37. Corrections. The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such supplementary facts or corrected information. [40 CFR § 71.5(b)]

3.38. Off-Permit Change Report. The permittee shall provide contemporaneous written notice to EPA of each off-permit change allowed to be made under Condition 2.15, except for changes that qualify as insignificant activities under 40 CFR § 71.5(c)(11). The written notice shall describe each change, the date of the change, any change in emissions, pollutants emitted, and any applicable requirements that would apply as a result of the change; [40 CFR §71.6(a)(12)]

3.39. Section 502(b)(10) Change Report. The permittee is required to send a notice to EPA at least 7 days in advance of any section 502(b)(10) change allowed to be made under Condition 2.16. The notice must describe the change, when it will occur and any change in emissions, and identify any permit terms or conditions made inapplicable as a result of the change. The permittee shall attach each notice to its copy of this permit. [40 CFR § 71.6(a)(13)(i)(A)]

3.40. Address. Unless otherwise specified in this permit, any documents required to be submitted under this permit, including reports, test data, monitoring data, notifications, compliance certifications, fee calculation worksheets, and applications for renewals and permit modifications shall be submitted to the EPA address below. A copy of each document submitted to EPA that does not contain confidential business information shall be sent to the Tribal address below:

Original documents go to EPA at:	Copies go to Tribe at:
Part 71 Air Quality Permits U.S. EPA - Region 10, AWT-150 1200 Sixth Avenue, Suite 900 Seattle, WA 98101-3140	Air Quality Coordinator The Confederated Tribes of the Warm Springs Reservation of Oregon P.O. Box C Warm Springs, Oregon 97761-3001

[40 CFR §§ 71.5(d), 71.6(c)(1) and 71.9(h)(2)]

Part 71 Emission and Fee Reporting

3.41. Part 71 Annual Emission Report. No later than the date specified in Condition 4.1 of each year, the permittee shall submit to EPA an annual report of actual emissions for the preceding calendar year. [40 CFR § 71.9(h)(1)]

3.41.1. "Actual emissions" means the actual rate of emissions in tons per year of any "regulated pollutant (for fee calculation)," as defined in 40 CFR § 71.2, emitted from a Part 71 source over the preceding calendar year. Actual emissions shall be calculated using each emissions unit's actual operating hours, production rates, in-place control equipment, and types of materials processed, stored, or combusted during the preceding calendar year. [40 CFR § 71.9(c)(6)]

3.41.2. Actual emissions shall be computed using methods required by the permit for determining compliance. [40 CFR § 71.9(h)(3)]

3.41.3. Actual emissions shall include fugitive emissions. [40 CFR § 71.9(c)(1)]

3.42. Part 71 Fee Calculation Worksheet. Based on the annual emission report required in Condition 3.41 and no later than the date specified in Condition 4.1 of each year, the permittee shall submit to EPA a fee calculation worksheet (blank forms provided by EPA) and a photocopy of each fee payment check (or other confirmation of actual fee paid).

[40 CFR §§ 71.9(c)(1), 71.9(e)(1) and 71.9(h)(1)]

3.42.1. The annual emissions fee shall be calculated by multiplying the total tons of actual emissions of each "regulated pollutant (for fee calculation)," emitted from the source by the presumptive emission fee (in dollars/ton) in effect at the time of calculation. The presumptive emission fee is revised each calendar year and is available from EPA prior to the start of each calendar year. [40 CFR § 71.9(c)(1)]

3.42.2. The permittee shall exclude the following emissions from the calculation of fees:

3.42.2.1 The amount of actual emissions of each regulated pollutant (for fee calculation) that the source emits in excess of 4,000 tons per year;

3.42.2.2 Actual emissions of any regulated pollutant (for fee calculation) already included in the fee calculation; and

3.42.2.3 The insignificant quantities of actual emissions not required to be listed or calculated in a permit application pursuant to 40 CFR § 71.5(c)(11).

[40 CFR § 71.9(c)(5)]

3.43. Part 71 Annual Fee Payment. No later than the date specified in Condition 4.1 of each year, the permittee shall submit to EPA full payment of the annual permit fee based on the fee calculation worksheet required in Condition 3.42. [40 CFR §§ 71.9(a), 71.9(c)(1) and 71.9(h)(1)]

3.43.1. The fee payment and a completed fee filing form shall be sent to:

U.S.EPA
FOIA and Miscellaneous Payments
Cincinnati Finance Center
P. O. Box 979078
St Louis, MO 63197-9000

[40 CFR § 71.9(k)(2)]

3.43.2. The fee payment shall be in United States currency and shall be paid by money order, bank draft, certified check, corporate check, or electronic funds transfer payable to the order of the U.S. Environmental Protection Agency. [40 CFR § 71.9(k)(1)]

3.43.3. The permittee, when notified by EPA of additional amounts due, shall remit full payment within 30 days of receipt of an invoice from EPA. [40 CFR § 71.9(j)(2)]

3.43.4. If the permittee thinks an EPA assessed fee is in error and wishes to challenge such fee, the permittee shall provide a written explanation of the alleged error to EPA along with full payment of the EPA assessed fee. [40 CFR § 71.9(j)(3)]

3.43.5. Failure of the permittee to pay fees in a timely manner shall subject the permittee to assessment of penalties and interest in accordance with 40 CFR § 71.9(l).

[40 CFR § 71.9(l)]

3.44. The annual emission report and fee calculation worksheet (and photocopy of each fee payment check), required in Conditions 3.41 and 3.42, shall be submitted to EPA at the address listed in Condition 3.40 of this permit.[1] [40 CFR § 71.9(k)(1)]

3.45. The annual emission report and fee calculation worksheet (and photocopy of each fee payment check), required in Conditions 3.41 and 3.42, shall be certified by a responsible official in accordance with Condition 3.50 of this permit. [40 CFR § 71.9(h)(2)]

Annual Registration

3.46. The permittee shall submit an annual registration report that consists of estimates of the total actual emissions from the air pollution source for the following air pollutants: PM, PM_{10}, $PM_{2.5}$, SO_X, NO_X, CO, VOC, lead and lead compounds, ammonia, fluorides (gaseous and particulate), sulfuric acid mist, hydrogen sulfide, total reduced sulfur (TRS), and reduced sulfur compounds, including all calculations for the estimates. Emissions shall be calculated using the actual operating hours, production rates, in-place control equipment, and types of materials processed, stored, or combusted during the preceding calendar year.

[40 CFR §§ 49.138(e)(3)(xii), (e)(4) and (f)]

3.46.1. The emission estimates required by Condition 3.46 shall be based upon actual test data or, in the absence of such data, upon procedures acceptable to the Regional Administrator. Any emission estimates submitted to the Regional Administrator shall be verifiable using currently accepted engineering criteria. The following procedures are generally acceptable for estimating emissions from air pollution sources:

3.46.1.1 Source-specific emission tests;

3.46.1.2 Mass balance calculations;

3.46.1.3 Published, verifiable emission factors that are applicable to the source;

3.46.1.4 Other engineering calculations; or

[1] The permittee should note that an annual emissions report, required at the same time as the fee calculation worksheet by 40 CFR § 71.9(h), has been incorporated into the fee calculation worksheet.

3.46.1.5 Other procedures to estimate emissions specifically approved by the Regional Administrator.

[40 CFR §§ 49.138(e)(4) and (f)]

3.46.2. The annual registration report shall be submitted with the annual emission report and fee calculation worksheet required by Conditions 3.41 and 3.42 of this permit. The permittee may submit a single combined report provided that the combined report clearly identifies which emissions are the basis for the annual registration report, the part 71 annual emission report, and the part 71 fee calculation worksheet. All registration information and reports shall be submitted on forms provided by the Regional Administrator. [40 CFR §§ 49.138(d) and (f)]

Periodic and Deviation Reporting

3.47. Semi-Annual Monitoring Report. The permittee shall submit to EPA reports of any required monitoring for each six month reporting period from July 1 to December 31 and from January 1 to June 30. All reports shall be submitted to EPA and shall be postmarked by the 60th day following the end of the reporting period. All instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official consistent with Condition 3.50. [40 CFR § 71.6(a)(3)(iii)(A)]

3.48. Deviation Report. The permittee shall promptly report to EPA, by telephone or facsimile, deviations from permit conditions, including those attributable to upset conditions as defined in this permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. The report shall be made using the following numbers:

Telephone: (206) 553-1331
Attn: Part 71 Deviation Report

[40 CFR § 71.6(a)(3)(iii)(B)]

3.48.1. For the purposes of Conditions 3.47 and 3.48, deviation means any situation in which an emissions unit fails to meet a permit term or condition. A deviation is not always a violation. A deviation can be determined by observation or through review of data obtained from any testing, monitoring, or record keeping required by this permit. For a situation lasting more than 24 hours, each 24-hour period is considered a separate deviation. Included in the meaning of deviation are any of the following:

3.48.1.1 A situation where emissions exceed an emission limitation or standard;

3.48.1.2 A situation where process or emissions control device parameter values indicate that an emission limitation or standard has not been met;

3.48.1.3 A situation in which observations or data collected demonstrate noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit (including indicators of compliance revealed through parameter monitoring);

3.48.1.4 A situation in which any testing, monitoring, recordkeeping or reporting required by this permit is not performed or not performed as required;

3.48.1.5 A situation in which an exceedance or an excursion, as defined in 40 CFR Part 64, occurs; and

3.48.1.6 Failure to comply with a permit term that requires submittal of a report.

[40 CFR § 71.6(a)(3)(iii)(C)]

3.48.2. For the purpose of Condition 3.48 of the permit, prompt is defined as any definition of prompt or a specific time frame for reporting deviations provided in an underlying applicable requirement as identified in this permit. Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

3.48.2.1 For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report must be made within 24 hours of the occurrence;

3.48.2.2 For emissions of any regulated pollutant excluding those listed in Condition 3.48.2.1 above, that continue for more than two hours in excess of permit requirements, the report must be made within 48 hours of the occurrence; or

3.48.2.3 For all other deviations from permit requirements, the report shall be submitted with the semi-annual monitoring report required in Condition 3.47.

[40 CFR § 71.6(a)(3)(iii)(B)]

3.48.3. Within ten working days of the occurrence of a deviation as provided in Condition 3.48.2.1 or 3.48.2.2 above, the permittee shall also submit a written notice, which shall include a narrative description of the deviation and updated information as listed in Condition 3.48, to EPA, certified consistent with Condition 3.50 of this permit.
[40 CFR §§ 71.6(a)(3)(i)(B) and (iii)(B)]

Annual Compliance Certification

3.49. The permittee shall submit to EPA a certification of compliance with permit terms and conditions, including emission limitations, standards, or work practices, postmarked by February 28 of each year and covering the permit or permits in effect during the previous calendar year. The compliance certification shall be certified as to truth, accuracy, and completeness by a responsible official consistent with Condition 3.50 of this permit. [40 CFR § 71.6(c)(5)]

3.49.1. The annual compliance certification shall include the following:

3.49.1.1 The identification of each permit term or condition that is the basis of the certification;

3.49.1.2 The identification of the method(s) or other means used by the permittee for determining the compliance status with each term and condition during the certification period. Such methods and other means shall include, at a minimum, the methods and means required in this permit. If necessary, the permittee also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Clean Air Act, which prohibits knowingly making a false certification or omitting material information; and

3.49.1.3 The status of compliance with each term and condition of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall be based on the method or means designated above. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any

periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 occurred.

[40 CFR § 71.6(c)(5)(iii)]

Document Certification

3.50. Any document required to be submitted under this permit shall be certified by a responsible official as to truth, accuracy, and completeness. Such certifications shall state that based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. [40 CFR §§ 71.5(d), 71.6(c)(1) and 71.9(h)(2)]

Permit Renewal

3.51. The permittee shall submit a timely and complete application for permit renewal at least six months, but not more than 18 months, prior to the date of expiration of this permit.
[40 CFR §§ 71.5(a)(1)(iii), 71.7(b) and 71.7(c)(1)(ii)]

3.52. The application for renewal shall include the current permit number, a description of permit revisions and off-permit changes that occurred during the permit term and were not incorporated into the permit during the permit term, any applicable requirements that were promulgated and not incorporated into the permit during the permit term, and other information required by the application form. [40 CFR §§ 71.5(a)(2) and 71.5(c)(5)]

4. Facility-Specific Requirements

Fees and Emission Reports Due Date

4.1. Unless otherwise specified, fees and emission reports required by this permit are due annually on April 1. [40 CFR §§ 71.9(a) and 71.9(h)]

Fuel Sulfur Limits

4.2. The permittee shall not sell, distribute, use, or make available for use any solid fuel that contains more than 2.0 percent sulfur by weight. [40 CFR § 49.130(d)(7)]

4.2.1. Compliance with the sulfur limit is determined using ASTM method E775-87(2004).
[40 CFR § 49.130(e)(3)]

Fuel Sulfur Monitoring and Recordkeeping

4.3. The permittee shall keep records showing that only wood is combusted in the boiler.
[40 CFR § 49.130(f)(1)(iii)]

Visible and Fugitive Emission Monitoring and Recordkeeping

4.4. Except as provided for in Condition 4.11, once each calendar quarter, the permittee shall visually survey each emission unit and any other pollutant emitting activity for the presence of visible emissions or fugitive emissions of particulate matter.

4.4.1. The observer conducting the visual survey must be trained and knowledgeable regarding the effects of background contrast, ambient lighting, observer position relative to lighting and wind, and the presence of uncombined water on the visibility of emissions (see 40 CFR part 60, Appendix A, Method 22).

4.4.2. For the surveys, the observer shall select a position that enables a clear view of the emission point to be surveyed, that is at least 15 feet, but not more than 0.25 miles,

from the emission point, and where the sunlight is not shining directly in the observer's eyes.

4.4.3. The observer shall continuously watch for visible emissions from each potential emission point for at least 15 seconds.

4.4.4. Any observed visible emissions or fugitive emissions of particulate matter (other than uncombined water) shall be recorded as a positive reading associated with the emission unit or pollutant emitting activity.

4.4.5. Surveys shall be conducted while the emission unit or pollutant emitting activity is operating, and during daylight hours.

[40 CFR § 71.6(a)(3)(i)(B)]

4.5. If the survey conducted pursuant to Condition 4.4 identifies any visible emissions or fugitive emissions of particulate matter, the permittee shall:

4.5.1. Immediately upon conclusion of the visual survey in Condition 4.4, investigate the source and reason for the presence of visible emissions or fugitive emissions; and

4.5.2. As soon as practicable, take appropriate corrective action.

[40 CFR § 71.6(a)(3)(i)(B)]

4.6. If the corrective actions undertaken pursuant to Condition 4.5.2 do not eliminate the visible or fugitive emissions, the permittee shall within 24 hours of the visual survey in Condition 4.4 determine the opacity of the emissions in question, for a 30-minute duration, using the procedures specified in Condition 3.9.1. [40 CFR § 71.6(a)(3)(i)(B)]

4.7. If any 6-minute average opacity determined pursuant to Condition 4.6 or 4.8 is greater than 20%, the permittee shall determine the opacity of the emissions in question daily, for a 30-minute duration each day, using the procedures specified in Condition 3.9.1 until no 6-minute average opacity is greater than 20% for two consecutive days. [40 CFR § 71.6(a)(3)(i)(B)]

4.8. If the opacity determination required in Condition 4.6, or if two consecutive daily opacity determinations required by Condition 4.7, indicate no 6-minute average opacity greater than 20%, the permittee shall determine opacity of the emissions in question weekly, for a 30-minute duration each week, for three additional weeks using the procedures specified in Condition 3.9.1. [40 CFR § 71.6(a)(3)(i)(B)]

4.9. The permittee shall maintain records of the following:

4.9.1. Details of each visual survey, including date, time, observer and results for each emission unit and any other pollutant emitting activity;

4.9.2. Date, time and type of any investigation conducted pursuant to Condition 4.5.1;

4.9.3. Findings of the investigation, including the reasons for the presence of visible emissions or fugitive emissions of particulate matter;

4.9.4. Date, time and type of corrective actions taken pursuant to Condition 4.5.2;

4.9.5. Field, observation and data reduction records for any EPA Reference Method 9 determination conducted on the source of visible or fugitive emissions pursuant to Conditions 4.6 through 4.8.

[40 CFR § 71.6(a)(3)(i)(B)]

4.10. Any 6-minute average opacity determined to be in excess of 20% is a deviation and subject to the provisions of Conditions 3.47 and 3.48. [40 CFR § 71.6(a)(3)(i)(B)]

4.11. The requirements of Conditions 4.4 through 4.10 shall not apply to emissions from PH5.

[40 CFR § 71.6(a)(3)(i)(B)]

Facility-Wide HAP Emission Limits and Work Practice Requirements

4.12. HAP emissions from this facility shall not exceed 24 tons per year as determined on a rolling 12-month basis by calculating the emissions (tons) for each month and adding the emissions (tons) for the previous eleven months.

4.12.1. Monthly PH5 emissions (tons) shall be determined by multiplying the recorded monthly heat input rate (MMBtu/month) determined pursuant to Condition 4.17 by 0.0220 lb/MMBtu and dividing by 2000 lb/ton.

4.12.2. Monthly KLN-N and KLN-W emissions (tons) shall be determined by multiplying the recorded monthly specie-specific and temperature-specific dry lumber production rates (thousand board feet (mbf)/month) determined pursuant to Condition 4.19 by the corresponding specie-specific and temperature specific total HAP emission factors (lb/mbf) presented in Appendix A of this permit, summing, and dividing by 2000 lb/ton.

[Permit No. R10NT500401]

4.13. Emissions of any single HAP from this facility shall not exceed 9 tons per year as determined on a rolling 12-month basis by calculating the emissions (tons) for each month and adding the emissions (tons) for the previous eleven months.

4.13.1. Monthly PH5 emissions (tons) shall be determined by multiplying the recorded monthly heat input rate (MMBtu/month) determined pursuant to Condition 4.17 by the emission factors (lb/MMBtu) presented in Appendix B and dividing by 2000 lb/ton.

4.13.2. Monthly KLN-N and KLN-W emissions (tons) shall be determined by multiplying the recorded monthly specie-specific and temperature-specific dry lumber production rates (mbf/month) determined pursuant to Condition 4.19 by the corresponding specie-specific and temperature-specific single HAP emission factors (lb/mbf) presented in Appendix A of this permit, summing, and dividing by 2000 lb/ton.

[Permit No. R10NT500401]

Facility-Wide HAP Testing Requirements

4.14. No later than 120 days after issuance of this permit and subsequently thereafter each time the permittee employs EPA Reference Method 2 to determine PH5 stack gas volumetric flow rate, the permittee shall conduct stack testing and perform fuel sampling and analysis to determine PH5's fuel-heat-input-to-steam-output ratio "FHISOR" (MMBtu/thousand lb (mlb)) using the methodology specified in the most recent version of EPA Region 10's "Procedure to Determine a Biomass Boiler's Fuel-Heat-Input-To-Steam-Output Ratio." [Permit No. R10NT500401]

4.15. During each stack test run conducted to determine PH5's FHISOR as directed by Condition 4.14, the permittee shall:

4.15.1. Combust wood residue (species, moisture content and by-product specific) most often consumed during the most recent twelve months of operation;

4.15.2. Generate steam within ten percent of the maximum pressure (psig), temperature (°F) and mass flow rate (mlb/hr) observed during the most recent twelve months of operation;

4.15.3. Record the species, moisture content and category of wood residue by-product combusted in the boiler and whether the fuel was generated on-site or off. If more than

one species or more than one category of wood residue by-product is combusted, then estimate and record the percentage of each; and

4.15.4. Measure and record the steam pressure (psig), temperature (°F) and mass flow rate (mlb/hr) no less than once every five minutes.

[Permit No. R10NT500401]

Facility-Wide HAP Monitoring and Recordkeeping Requirements

4.16. Each month, the permittee shall calculate and record facility-wide monthly and rolling 12-month total emissions (tons) for all HAP-emitting activities at the facility. [Permit No. R10NT500401]

4.17. The permittee shall determine the monthly heat input to PH5 as follows:

4.17.1. Continuously track and record the boiler's steam generating rate in accordance with Condition 4.18 and total the month's steam production (mlb/month);

4.17.2. Employ a FHISOR of 1.52 MMBtu/mlb to calculate monthly heat input to the boiler until testing is performed pursuant to Condition 4.14; and

4.17.3. Once a test-derived FHISOR (MMBtu/mlb) has been determined pursuant to Condition 4.14, monthly heat input shall be determined by multiplying the monthly steam production (mlb/month) by the most recent FHISOR (MMBtu/mlb).

[Permit No. R10NT500401]

4.18. The permittee shall install, calibrate, operate and maintain, in accordance with manufacturer specifications, equipment necessary to measure and record PH5 steam pressure (psig), temperature (°F) and mass flow rate (mlb/hr).

4.18.1. The monitoring system shall provide for continuous measurement/display, one-hour block averages recorded with at least 90% monthly data capture.

4.18.2. At least annually, the permittee shall verify and document the accuracy of the monitoring equipment in accordance with manufacturer's specifications.

[Permit No. R10NT500401]

4.19. The permittee shall determine the monthly volume of lumber dried (mbf/month) in KLN-N and KLN-W according to species of lumber and maximum drying temperature (°F).

4.19.1. For each kiln charge, track and record the species and volume of lumber dried (mbf) and the maximum dry bulb temperature (ºF) of heated air entering the lumber stack in accordance with Condition 4.20.

4.19.2. Sort monthly kiln charges by species of lumber and into one of the following two categories: (a) maximum drying temperature less than or equal to 200°F and (b) maximum drying temperature greater than 200°F.

4.19.3. Sum the volumes (mbf) of kiln charges sorted in accordance with Condition 4.19.2.

[Permit No. R10NT500401]

4.20. The permittee shall install, calibrate, operate and maintain, in accordance with manufacturer specifications, equipment necessary to measure and record KLN-N and KLN-W dry bulb temperature (°F) of heated air entering the lumber stack.

4.20.1. The monitoring system shall provide for continuous measurement/display, one-hour block averages recorded with at least 90% monthly data capture;

4.20.2. At least annually, the permittee shall verify and document the accuracy of the monitoring equipment in accordance with manufacturing specifications.

[Permit No. R10NT500401]

4.21. The permittee shall maintain records of emission calculations and parameters used to calculate emissions for at least five years. [Permit No. R10NT500401]

Facility-Wide HAP Reporting Requirements

4.22. Once each year, on or before April 1, the permittee shall, along with the annual registration required by Condition 3.46, submit to EPA a report containing the twelve monthly rolling 12-month emissions calculations for the previous calendar year.

4.22.1. The report shall contain a description of all emissions estimating methods used, including emission factors and their sources, assumptions made and production data.

[Permit No. R10NT500401]

NESHAP Subpart JJJJJJ Work Practice and Emission Reduction Measures

4.23. NESHAP Subpart JJJJJJ PH5 Performance Tune-up. The permittee shall conduct a performance tune-up of the boiler no later than March 21, 2014, and every five years thereafter subject to the following: [40 CFR §§ 63.11196(a)(1), 63.11201(b), 63.11210(c), 63.11223(a)through (c) and Table 2 to Subpart JJJJJJ of Part 63]

4.23.1. Each performance tune-up shall be conducted no more than 61 months after the previous tune-up. [40 CFR § 63.11223(c)]

4.23.2. If the boiler is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 days of startup. [40 CFR § 63.11223(b)(7)]

4.23.3. Conduct the tune-up while the boiler is combusting biomass. [40 CFR § 63.11223(a)]

4.23.4. Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. The inspection may be delayed until the next scheduled boiler shutdown, not to exceed 36 months from the previous inspection. [40 CFR § 63.11223(b)(3)]

4.23.5. Optimize total emissions of CO. This optimization shall be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the boiler is subject. [40 CFR §§ 63.11223(b)(4)]

4.24. NESHAP Subpart JJJJJJ Energy Assessment for PH5, KLN-N and KLN-W. The permittee shall satisfy Condition 4.24.1 or 4.24.2 no later than March 21, 2014:
[40 CFR § 63.11196(a)(3), 63.11201(b), 63.11210(c) and Table 2 to Subpart JJJJJJ of Part 63]

4.24.1. Have a one-time energy assessment performed or amended in accordance with Condition 4.25 and as follows:
[40 CFR § 63.11201(b) and Table 2 to Subpart JJJJJJ of Part 63]

4.24.1.1 The energy assessment (and in the case of an amendment; the underlying assessment) shall be completed on or after January 1, 2008.
[40 CFR § 63.11201(b) and Table 2 to Subpart JJJJJJ of Part 63]

4.24.1.2 An energy assessment performed after February 1, 2013 shall be conducted by a qualified energy assessor. [Table 2 to Subpart JJJJJJ of Part 63]

4.24.2. Operate under an energy management program compatible with ISO 50001 that includes the affected units.

[40 CFR § 63.11201(b) and Table 2 to Subpart JJJJJJ of Part 63]

4.25. NESHAP Subpart JJJJJJ One-Time Energy Assessment Requirements for PH5, KLN-N and KLN-W. If the permittee elects to have a one-time energy assessment performed or amended to comply with Condition 4.24, the assessment (or amended assessment) shall include the following: [40 CFR § 63.11201(b), 40 CFR § 63.11237 and Table 2 to Subpart JJJJJJ of Part 63]

4.25.1. An on-site evaluation up to 24 technical labor hours in duration (but may be longer at the discretion of the permittee) that includes the following: [40 CFR § 63.11237]

4.25.1.1 A visual inspection of the boiler system; [Table 2 to Subpart JJJJJJ of Part 63]

4.25.1.2 An evaluation of operating characteristics of the boiler system, specifications of energy use systems, operating and maintenance procedures, and unusual operating constraints; [Table 2 to Subpart JJJJJJ of Part 63]

4.25.1.3 An inventory of major energy use systems consuming energy from the boiler and which are under control of the permittee[2]; [Table 2 to Subpart JJJJJJ of Part 63]

4.25.1.4 A review of available architectural and engineering plans, facility operating and maintenance procedures and logs, and fuel usage; [Table 2 to Subpart JJJJJJ of Part 63]

4.25.2. A list of major energy conservation measures that are within the permittee's control; [Table 2 to Subpart JJJJJJ of Part 63]

4.25.3. A list of the energy savings potential of the energy conservation measures identified; and [Table 2 to Subpart JJJJJJ of Part 63]

4.25.4. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments. [Table 2 to Subpart JJJJJJ of Part 63]

4.26. NESHAP Subpart JJJJJJ PH5 General Duty Requirement. At all times, the permittee must operate and maintain the boiler, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the permittee to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to EPA that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [40 CFR § 63.11205(a)]

NESHAP Subpart JJJJJJ Monitoring and Recordkeeping Requirements

4.27. NESHAP Subpart JJJJJJ PH5 Performance Tune-up Monitoring. The permittee shall measure and record the concentration of CO in parts per million, by volume, and O_2 in volume percent, in the boiler's effluent stream before and after the performance tune-up conducted to satisfy Condition 4.23. Measurements may be either on a dry or wet basis, as long as it is the same basis before and

[2] As discussed in Section 4.3 of the accompanying Statement of Basis, the lumber drying energy use system for which WSFPI is required to conduct an energy assessment consists of KLN-N and KLN-W.

after the performance tune-up is performed. Measurements may be taken using a portable CO analyzer. [40 CFR § 63.11223(b)(5)]

4.28. NESHAP Subpart JJJJJJ Recordkeeping for Compliance – PH5, KLN-N and KLN-W. The permittee shall maintain the following records: [40 CFR § 63.11225(c)]

4.28.1. A copy of each notification and report submitted to comply with NESHAP Subpart JJJJJJ and all documentation supporting any Initial Notification or Notification of Compliance Status submitted to EPA.
[40 CFR §§ 63.10(b)(2)(xiv) and 63.11225(c)(1)]

4.28.2. Records identifying the boiler, the date of tune-up, the procedures followed for tune-up, and the manufacturer's specifications to which the boiler was tuned.
[40 CFR § 63.11225(c)(2)(i)]

4.28.3. A copy of the energy assessment report for the boiler and its major energy use systems.
[40 CFR § 63.11225(c)(2)(iii)]

4.29. NESHAP Subpart JJJJJJ PH5 Recordkeeping for General Duty Requirement. The permittee shall maintain the following records: [40 CFR § 63.11225(c)]

4.29.1. Records of the occurrence and duration of each malfunction of the boiler, or of the associated air pollution control and monitoring equipment. [40 CFR § 63.11225(c)(4)]

4.29.2. Records of actions taken during periods of malfunction to minimize emissions in accordance with Condition 4.26, including corrective actions to restore the malfunctioning boiler, air pollution control, or monitoring equipment to its normal or usual manner of operation. [40 CFR § 63.11225(c)(5)]

4.30. NESHAP Subpart JJJJJJ PH5 Recordkeeping for Use of Non-Hazardous Secondary Materials as Fuels. The permittee shall maintain the following records:

4.30.1. If the boiler combusts non-hazardous secondary materials that have been determined not to be a solid waste pursuant to 40 CFR § 241.3(b)(1), the permittee shall keep a record which documents how the secondary material meets each of the legitimacy criteria under 40 CFR § 241.3(d)(1).

4.30.2. If the boiler combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR § 241.3(b)(4), the permittee shall 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).

4.30.3. If the boiler combusts a fuel that received a non-waste determination pursuant to the petition process submitted under 40 CFR § 241.3(c), the permittee shall keep a record that documents how the fuel satisfies the requirements of the petition process.

4.30.4. If the boiler combusts non-hazardous secondary materials as fuel per 40 CFR §241.4, the permittee shall keep records documenting that the material is a listed non-waste under 40 CFR § 241.4(a).

[40 CFR § 63.11225(c)(2)(ii)]

NESHAP Subpart JJJJJJ Reporting Requirements

4.31. NESHAP Subpart JJJJJJ PH5 Performance Tune-up Reporting. Maintain on-site and submit to EPA as part of the reporting satisfying Condition 3.47 the following information for each performance tune-up conducted to satisfy Condition 4.23:

[40 CFR § 63.11223(b)(6)]

4.31.1. The concentration of CO in the boiler's effluent stream in parts per million, by volume, and O_2 in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler. [40 CFR § 63.11223(b)(6)(i)]

4.31.2. A description of any corrective action taken as a part of the tune-up of the boiler. [40 CFR § 63.11223(b)(6)(ii)]

4.32. NESHAP Subpart JJJJJJ Notification of Compliance Status. The permittee shall submit a Notification of Compliance Status to EPA no later than July 19, 2014, and the notification shall be signed by the permittee's responsible official certifying its accuracy and attesting to whether the source has complied with NESHAP Subpart JJJJJJ. [40 CFR §§ 63.9(h)(2)(i) and 63.11225(a)(4)]

4.32.1. The notification shall 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). [40 CFR § 63.11225(a)(4)(vi)]

4.32.2. The notification shall provide the following information: [40 CFR §§ 63.9(h)(1), 63.11214(b) and (c), and 63.11225(a)(4)]

4.32.2.1 The methods that were used to determine compliance; [40 CFR § 63.9(h)(2)(i)(A)]

4.32.2.2 The methods that will be used for determining continuing compliance, including a description of monitoring and reporting requirements and test methods; [40 CFR § 63.9(h)(2)(i)(C)]

4.32.2.3 A statement by the permittee as to whether the boiler has complied with NESHAP Subpart JJJJJJ or other requirements. [40 CFR § 63.9(h)(2)(i)(G)]

4.32.2.4 The statement, "This facility complies with the requirements in § 63.11214 to conduct an initial tune-up of the boiler." [40 CFR § 63.11225(a)(4)(ii)]

4.32.2.5 The statement, "This facility has had an energy assessment performed according to § 63.11214(c)." [40 CFR § 63.11225(a)(4)(iii)]

4.32.2.6 The statement, "No secondary materials that are solid waste were combusted in any affected unit." [40 CFR § 63.11225(a)(4)(v)]

4.33. NESHAP Subpart JJJJJJ Annual Compliance Certification Report. Each year, the permittee shall prepare and submit to EPA by February 28 an Annual Compliance Certification Report for the previous calendar year. The report shall be signed by the permittee's responsible official and provide the following information: [40 CFR § 63.11225(b)]

4.33.1. Company name and address. [40 CFR §63.11225(b)(1)]

4.33.2. Statement by a responsible official, with the official's name, title, phone number, email address and signature, certifying the truth, accuracy and completeness of the notification and a statement of whether the source has complied with all the relevant standards and other requirements of NESHAP Subpart JJJJJJ. [40 CFR §63.11225(b)(2)]

4.33.3. The statement, "This facility complies with the requirements in § 63.11223 to conduct a 5-year tune-up of the boiler." [40 CFR §63.11225(b)(2)(i)]

4.33.4. The statement, "No secondary materials that are solid waste were combusted in any affected unit." [40 CFR §63.11225(b)(2)(i)(ii)]

4.33.5. A description of any deviations from the applicable requirements during the previous calendar year, the time periods during which the deviations occurred, and the corrective actions taken. [40 CFR § 63.11225(b)(3)]

4.34. NESHAP Subpart JJJJJJ PH5 Notification of Combustion of Solid Waste. The permittee shall provide 30 days prior notice to EPA of the date upon which combusting of solid waste will commence or recommence in the boiler. The notification shall identify the following: [40 CFR § 63.11225(f)]

4.34.1. The name of the owner or operator of the boiler, the location of boiler, identification of the boiler as a boiler that will commence combusting solid waste, and the date of the notice. [40 CFR § 63.11225(f)(1)]

4.34.2. The currently applicable subcategory listed at 40 CFR § 63.11200. [40 CFR § 63.11225(f)(2)]

4.34.3. The date on which the permittee became subject to the currently applicable emission limits. [40 CFR § 63.11225(f)(3)]

4.34.4. The date upon which the permittee will commence combusting solid waste**.** [40 CFR § 63.11225(f)(4)]

4.35. NESHAP Subpart JJJJJJ PH5 Notification of Fuel Switch, Physical Change or Permit Limit. The permittee shall provide notice to EPA if the permittee switched fuels or made a physical change to the boiler and the fuel switch or change resulted in (a) the applicability of a different subcategory of NESHAP Subpart JJJJJJ listed at 40 CFR § 63.11200, (b) the boiler becoming subject to NESHAP Subpart JJJJJJ, or (c) the boiler switching out of NESHAP Subpart JJJJJJ due to a change to 100 percent natural gas. Notice shall also be provided if EPA issues a permit limit to the permittee that results in the permittee being subject to NESHAP Subpart JJJJJJ. Notice shall be provided within 30 days of the change, and the notification shall identify the following: [40 CFR § 63.11225(g)]

4.35.1. The name of the owner or operator of the boiler, the location of the boiler, identification of the boiler as a boiler that has switched fuels, was physically changed, or took a permit limit, and the date of the notice. [40 CFR § 63.11225(g)(1)]

4.35.2. The date upon which the fuel switch, physical change, or permit limit occurred. [40 CFR § 63.11225(g)(2)]

Monitoring for PSD Modifications to the Facility

4.36. Where there is a reasonable possibility (as defined in 40 CFR § 52.21(r)(6)(vi)) that a project (other than projects at a source with a plantwide applicability limitation (PAL)) that is not a part of a major modification may result in a significant emissions increase of any regulated NSR pollutant and the permittee elects to use the method specified in 40 CFR § 52.21(b)(41)(ii)(a) through (c) for calculating projected actual emissions, the permittee shall perform the following:

4.36.1. Before beginning actual construction of the project, document and maintain a record of the following information.

4.36.1.1 A description of the project.

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

4.36.1.3 A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of

emissions excluded under 40 CFR § 52.21(b)(41)(ii)(c) and an explanation for why such amount was excluded, and any netting calculations, if applicable.

4.36.2. Monitor the emission of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in Condition 4.36.1.2; and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five years following resumption of regular operations after the change, or for a period of ten years following resumption of regular operations after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

[40 CFR § 52.21(r)(6)]

Reporting for PSD Modifications to the Facility

4.37. If monitoring and recordkeeping is required in Condition 4.36, the permittee shall report to EPA when the annual emissions, in tons per year, from the project identified in Condition 4.36.1.1 exceed the baseline actual emissions as documented and maintained pursuant to Condition 4.36.1.3 by a significant amount (as defined in 40 CFR § 52.21(b)(23)) for that regulated NSR pollutant , and when such emissions differ from the preconstruction projection as documented and maintained pursuant to Condition 4.36.1.3. Such report shall be submitted to EPA within 60 days after the end of such year. The report shall contain the following.

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

4.37.2. The annual emissions as calculated pursuant to Condition 4.36.2.

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

[40 CFR § 52.21(r)(6)]

5. Unit-Specific Requirements – PH5 (Hog Fuel-Fired Boiler)

PH5 Emission Limits and Work Practice Requirements

5.1. The permittee is prohibited from combusting any fuel other than wood in the boiler.

[Section 304(f)(4) of the Federal Clean Air Act and 40 CFR § 71.6(b)]

5.2. FARR SO_2 Emission Limit. Sulfur dioxide emissions from the boiler stack shall not exceed an average of 500 parts per million by volume, on a dry basis and corrected to seven percent oxygen, during any three-hour period.

5.1.1. Compliance with the SO_2 limit is determined using EPA Reference Methods 6, 6A, 6B, and 6C as specified in the applicability section of each method (see 40 CFR part 60, appendix A) or, alternatively, a continuous emission monitoring system (CEMS) that complies with Performance Specification 2 found in Appendix B of 40 CFR Part 60.

[40 CFR §§ 49.129(d)(1) and (e)]

5.3. FARR PM Emission Limit. Particulate matter emissions from the boiler stack shall not exceed an average of 0.46 grams per dry standard cubic meter (0.2 grains per dry standard cubic foot), corrected to seven percent oxygen, during any three-hour period.

5.3.1. Compliance with the PM limit is determined using EPA Reference Method 5 (see 40 CFR part 60, Appendix A).

[40 CFR §§ 49.125(d)(2) and (e)]

5.4. NSPS Subpart Db PM Emission Limit. The permittee shall not cause to be discharged from the boiler any gases that contain particulate matter in excess of 43 ng/J (0.10 lb/MMBtu) heat input, as determined by emission testing using the methods specified in Condition 5.11 and as specified in 40 CFR § 60.46b. The limit shall apply at all times except during periods of startup, shutdown or malfunction. [40 CFR §§ 60.43b(c)(1), 60.43b(g), and 60.46b]

5.5. NSPS Subpart Db Visible Emission Limit. The permittee shall not cause to be discharged into the atmosphere from the boiler any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity, as determined by emission testing using the method specified in Condition 5.11 and as specified in 40 CFR § 60.46b. The limit shall apply at all times except during periods of startup, shutdown or malfunction. [40 CFR §§ 60.43b(f), 60.43b(g), 60.46b, 60.11(c) and 60.11(e)]

5.6. Operational Requirements to Assure Compliance with FARR and NSPS Opacity Limit and PM Emission Limits. The permittee shall operate the boiler, multiclone and ESP as follows:

5.6.1. At all times that the boiler operates, the boiler exhaust shall be directed to the multiclone and ESP.

5.6.2. The multiclone and ESP shall be maintained in good operating condition and shall be operated at all times that the boiler is operational.

[40 CFR §§ 49.124(d)(1), 49.125(d)(2), 60.11(d), 60.43b(c)(1), 60.43b(f) and 71.6(a)(1)]

5.7. NSPS Good Air Pollution Control Practices. At all times, including periods of startup, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the boiler including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to EPA which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. [40 CFR § 60.11(d)]

5.8. NSPS Circumvention. The permittee shall not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable NSPS standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard that is based on the concentration of a pollutant in the gases discharged to the atmosphere.

[40 CFR § 60.12]

5.9. Synthetic Minor Modification NO_X Emission Limit. NO_X emissions from the boiler shall not exceed 126 tons per year as determined on a rolling 12-month basis by determining the emissions (tons) for each month and adding the emissions (tons) calculated for the previous eleven months.

5.9.1. Until a test-derived emission factor has been determined pursuant to Condition 5.13, monthly boiler emissions (tons) shall be determined by multiplying the recorded monthly steam generating rate (mlb/month) by an emission factor of 0.421 lb NO_X/mlb steam and dividing by 2000 lb/ton.

5.9.2. Once a test-derived emission factor has been determined pursuant to Condition 5.13, monthly boiler emissions shall be determined by multiplying the recorded monthly steam generating rate (mlb/month) by the most recent test-derived emission factor (lb NO_X/mlb steam) and dividing by 2000 lb/ton.

5.9.3. If 12-month rolling NO_X emissions (summed by adding monthly emissions determined in accordance with Conditions 5.9.1or 5.9.2) exceed 113 tons per year, monthly emissions shall be determined by totaling the hourly emissions measured by the NO_X continuous emission rate monitoring system (CERMS) as specified in Condition 5.24.

[Section 304(f)(4) of the Federal Clean Air Act and 40 CFR § 71.6(b)]

5.10. Synthetic Minor Modification VOC Emission Limit. VOC emissions from the boiler shall not exceed 21.5 tons per year as determined on a rolling 12-month basis by calculating the emissions (tons) for each month and adding the emissions (tons) calculated for the previous eleven months.

5.10.1. Until a test-derived emission factor has been determined pursuant to Condition 5.15, monthly boiler emissions (tons) shall be determined by multiplying the recorded monthly steam generating rate (mlb/month) by 0.054 lb VOC/mlb steam and dividing by 2000 lb/ton.

5.10.2. Once a test-derived emission factor has been determined pursuant to Condition 5.15, monthly boiler emissions shall be determined by multiplying the recorded monthly steam generated rate (mlb/month) by the most recent test-derived emission factor (lb VOC/mlb steam) and dividing by 2000 lb/ton.

[Section 304(f)(4) of the Federal Clean Air Act and 40 CFR § 71.6(b)]

PH5 Testing Requirements

5.11. NSPS PM and Opacity Performance Test. The permittee shall conduct a PM and opacity performance test six to nine months prior to expiration of the permit using the following test methods:

Pollutant	**Test Method***
PM	EPA Reference Methods 1, 3A or 3B, 5 and 19
Opacity	EPA Reference Method 9

* EPA Reference Methods are found in 40 CFR 60, Appendix A. [40 CFR §71.6(c)(1)]

5.11.1. All required testing shall be performed in accordance with the procedures specified under 40 CFR § 60.8(b), (c) and (f), and sampling facilities shall be provided as specified in 40 CFR § 60.8(e).

[40 CFR §§ 60.8(b), (c), (e), (f), 60.46b(b) and 60.46b(d)]

5.11.2. Each source test shall consist of at least three valid test runs while the permittee operates the boiler in the following manner:

5.11.2.1 Combust the wood residue (species, moisture content and by-product specific), or combination thereof, most often consumed during the most recent twelve months of operation; and

5.11.2.2 Generate steam within ten percent of the maximum pressure (psig), temperature (°F) and mass flow rate (mlb/hr) observed during the most recent twelve months of operation.

[40 CFR §§ 60.8(c), (f) and 71.6(c)(1)]

5.11.3. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

[40 CFR § 60.46b(d)(3)]

5.11.4. For each run using Reference Method 5, the emission rate (lb/MMBtu) is determined using:

5.11.4.1 The O_2 or CO_2 measurements and PM measurements;

5.11.4.2 The run-specific dry basis F factor (dscf/MMBtu) determined through sampling and analysis of representative composite fuel sample pursuant to Section 12.3.2 of Reference Method 19 and Sections 2 – 7 of the most recent version of EPA Region 10's "Procedure to Determine a Biomass Boiler's Fuel-Heat-Input-To-Steam-Output Ratio;" and

5.11.4.3 The dry basis emission rate calculation procedure (Equation 19-1) contained in Reference Method 19.

[40 CFR §§ 60.46b(d)(6) and 71.6(c)(1)]

5.11.5. Calculate and report the arithmetic average of all valid test runs. [40 CFR § 60.8(f)]

5.11.6. All required opacity testing shall be performed in accordance with 40 CFR §§ 60.11(b) and 60.11(e)(1)–(5). [40 CFR §§ 60.11(b) and (e)(1) through (5)]

5.11.6.1 An owner of operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the test and shall furnish the Administrator a written report of the monitoring results along with Reference Method 9 and particulate matter performance test results. [40 CFR §§ 60.11(e)(4) and 71.6(a)(3)(i)(B)]

5.11.6.2 An owner or operator of an affected facility shall conduct opacity observations concurrent with, and for the duration of each Reference Method 5 run. This requirement does not apply if the owner or operator submits, for compliance purposes, COMS data results produced during the Reference Method 5 run in lieu of Reference Method 9 observation data. [40 CFR §§ 60.46b(d) and 71.6(c)(1)]

5.11.7. During the source test, the permittee shall record the values (and time recorded) of the parameters specified in Condition 5.18.1. For monitoring devices that do not have continuous recording devices, the recorded values must consist of no fewer than three values recorded per test run. [40 CFR § 71.6(a)(3)(i)(B)]

5.12. Initial and Periodic Fuel Heat Input to Steam Output Ratio Derivation Test. Each time that testing is performed pursuant to Conditions 5.11, 5.13, 5.14, 5.15 and 5.16, the permittee shall conduct stack testing and perform fuel sampling and analysis to determine PH5's FHISOR (MMBtu/mlb) using the methodology specified in the most recent version of EPA Region 10's "Procedure to Determine a Biomass Boiler's Fuel-Heat-Input-To-Steam-Output Ratio."

5.12.1. Each source test shall consist of at least three valid test runs while the permittee operates the boiler in the following manner:

5.12.1.1 Combust the wood residue (species, moisture content and by-product specific), or combination thereof, most often consumed during the most recent twelve months of operation; and

5.12.1.2 Generate steam within ten percent of the maximum pressure (psig), temperature (°F) and mass flow rate (mlb/hr) observed during the most recent twelve months of operation.

5.12.2. During the source test, the permittee shall record the values (and time recorded) of the parameters specified in Condition 5.18.1. For monitoring devices that do not have

continuous recording devices, the recorded values must consist of no fewer than three values recorded per test run.

5.12.3. Calculate and report the arithmetic average of all valid test runs.

[40 CFR §§ 71.6(a)(3)(i)(B) and (C), 71.6(a)(3)(ii) and 71.6(c)(1)]

5.13. Initial NO_X Emission Factor Derivation Test. No later than 120 days after issuance of this permit, or no later than 120 days after re-start of the boiler if it is shut-down (due to seasonal shortage of logs) at any time within the first 120 days after permit issuance, the permittee shall measure NO_X emissions exiting the stack using EPA Reference Method (RM) 2 and 7E in Appendix A to 40 CFR part 60 while also measuring the boiler's steam generating rate to determine a NO_X emission factor (lb/mlb steam).

5.13.1. Each source test shall consist of at least three valid test runs while the permittee operates the boiler in the following manner:

5.13.1.1 Combust the wood residue (species, moisture content and by-product specific), or combination thereof, most often consumed during the most recent twelve months of operation; and

5.13.1.2 Generate steam within ten percent of the maximum pressure (psig), temperature (°F) and mass flow rate (mlb/hr) observed during the most recent twelve months of operation.

5.13.2. During the source test, the permittee shall record the values (and time recorded) of the parameters specified in Condition 5.18.1. For monitoring devices that do not have continuous recording devices, the recorded values must consist of no fewer than three values recorded per test run.

5.13.3. The result of each test run shall be presented as an emission factor in units of lb NO_X/mlb steam and calculated as follows:

$$NO_X\ EF = C \times \frac{1.194 \times 10^{-7}\ \text{lb/scf}}{\text{ppmv}} \times Q \times \frac{60\ \text{min}}{\text{hr}} / S$$

where: NO_X EF = NO_X emission factor in units of lb/mlb steam;

C = NO_X concentration as measured in units of ppmv;

1.194×10^{-7} lb/scf per ppmv is relationship for expressing NO_2 concentration based upon ideal gas law at EPA standard conditions. See Table 19-1 of Reference Method 19 to 40 CFR Part 60, Appendix A;

Q = Stack exhaust flow rate as measured in units of scf/min;

S = Steam generating rate as measured in units of mlb/hr; and

Values for C and Q shall be expressed on the same moisture basis.

5.13.4. Calculate and report the arithmetic average of all valid test runs.

5.13.5. The requirement to conduct an initial NO_X emission factor derivation test shall not apply if the permittee is calculating hourly NO_X emissions with a NO_X CERMS pursuant to Condition 5.24.

[40 CFR §§ 71.6(a)(3)(i)(B) and (C), 71.6(a)(3)(ii) and 71.6(c)(1)]

5.14. Periodic NO_X Emission Factor Derivation Test. The permittee shall measure NO_X emissions exiting the stack using the procedures specified in Condition 5.13 six to nine months prior to the expiration of the permit to determine a NO_X emission factor.

5.14.1. Additional testing shall be conducted at a frequency based upon the monthly calculated rolling 12-month actual emissions as follows:

If any 12-month rolling emissions determined pursuant to Condition 5.9…	**Additional NO_X testing shall be conducted …**
≥ 50% but < 75% of the emission limit in Condition 5.9	Once per two calendar years beginning no later than 120 days after determining the first 12-month period in which rolling emissions ≥ 50% of the emission limit in Condition 5.9
≥ 75% but < 90% of the emission limit in Condition 5.9	Once per calendar year beginning no later than 120 days after determining the first 12-month period in which rolling emissions ≥ 75% of the emission limit in Condition 5.9
≥ 90% of the emission limit in Condition 5.9	Not applicable (NO_X CERMS required).

5.14.1.1 Any decrease in 12-month rolling emissions shall not impact the frequency of additional testing once the requirement to conduct additional testing is triggered.

5.14.2. The requirement to conduct periodic NO_X emission factor derivation test shall not apply if the permittee is calculating hourly NO_X emissions with a CERMS pursuant to Condition 5.24.

[40 CFR § 71.6(a)(3)(i)(B)]

5.15. Initial VOC Emission Factor Derivation Test. No later than 120 days after issuance of this permit, or no later than 120 days after re-start of the boiler if it is shut-down (due to seasonal shortage of logs) at any time within the first 120 days after permit issuance, the permittee shall measure VOC emissions exiting the stack simultaneously using EPA Reference Methods (RM) 2 and 25 in Appendix A to 40 CFR part 60 while also measuring the boiler's steam generating rate to determine a VOC emission factor (lb/mlb steam).

5.15.1. Each source test shall consist of at least three valid test runs while the permittee operates the boiler in the following manner:

5.15.1.1 Combust the wood residue (species, moisture content and by-product specific), or combination thereof, most often consumed during the most recent twelve months of operation; and

5.15.1.2 Generate steam within ten percent of the maximum pressure (psig), temperature (°F) and mass flow rate (mlb/hr) observed during the most recent twelve months of operation.

5.15.2. During the source test, the permittee shall record the values (and time recorded) of the parameters specified in Condition 5.18.1. For monitoring devices that do not have continuous recording devices, the recorded values must consist of no fewer than three values recorded per test run.

5.15.3. RM25 shall be modified to include a pre-condenser to remove water; a 500˚C recovery temperature; a 10 liter tank; a performance audit sample; and, a blank sample train evaluation.

5.15.4. The results of each test run shall be presented as an emission factor in units of lb VOC/mlb steam and calculated as follows:

$$\text{VOC EF} = 1.355 \times C \times \frac{3.118\text{x}10^{-8}\ \text{lb/scf}}{\text{ppmv}} \times Q \times \frac{60\ \text{min}}{\text{Hr}} / S$$

Where: VOC EF = VOC emission factor in units of lb/mlb steam;

1.355 = factor to convert $VOC_{\text{as carbon}}$ to $VOC_{\text{as compound emitted}}$;

C = $VOC_{\text{as carbon}}$ concentration as measured in units of ppmv;

$3.118\text{x}10^{-8}$ lb/scf per ppmv $VOC_{\text{as carbon}}$ is relationship for expressing carbon concentration based upon ideal gas law at EPA standard conditions;

Q = Stack exhaust flow rate as measured in units of scf/min;

S = Steam generating rate as measured in units of mlb/hr; and

Values for C and Q shall be expressed on the same moisture basis.

5.15.5. Calculate and report the arithmetic average of all valid test runs.

[40 CFR §§ 71.6(a)(3)(i)(B) and (C), 71.6(a)(3)(ii) and 71.6(c)(1)]

5.16. Periodic Volatile Organic Compounds Emission Factor Derivation Test. The permittee shall measure VOC emissions exiting the stack using the procedures specified in Condition 5.15 six to nine months prior to the expiration of the permit to determine a VOC emission factor.

5.16.1. Additional testing shall be conducted at a frequency based upon the monthly calculated rolling 12-month actual emissions as follows:

If any 12-month rolling emissions determined pursuant to Condition 5.10…	**Additional VOC testing shall be conducted…**
≥ 50% but < 75% of the emission limit in Condition 5.10	Once per two calendar years beginning 120 days after determining 12-month rolling emissions ≥ 50% of the emission limit in Condition 5.10
≥ 75% but < 90% of the emission limit in Condition 5.10	Once per calendar year beginning 120 days after determining 12-month rolling emissions ≥ 75% of the emission limit in Condition 5.10
≥ 90% of the emission limit in Condition 5.10	Once per 6-month period beginning 120 days after determining 12-month rolling emissions ≥ 90% of the emission limit in Condition 5.10

5.16.1.1 Any decrease in 12-month rolling emissions shall not impact the frequency of additional testing once the requirement to conduct additional testing is triggered.

[40 CFR § 71.6(a)(3)(i)(B)]

PH5 Monitoring and Recordkeeping Requirements

5.17. Continuous Opacity Monitoring. The permittee shall install, calibrate, operate, and maintain a COMS for measuring the opacity (%) of emissions discharged to the atmosphere from the boiler and record the output of the system. [40 CFR §§ 64.3(b)(4), 64.6(c) and 60.48b(a)]

5.17.1. The procedures in 40 CFR § 60.13 shall be followed for installation, evaluation, and operation of the COMS. [40 CFR §§ 64.3(b)(4), 64.6(c), 60.48b(e) and 60.13]

5.17.2. The COMS shall be installed and certified using Performance Specification 1 (PS1) of 40 CFR 60, Appendix B.

[40 CFR §§ 64.3(b)(4), 64.6(c), 71.6(a)(3)(i)(B) and (C), 71.6(a)(3)(ii) and 71.6(c)(1)]

5.17.3. The span value for the COMS for measuring opacity shall be between 60 and 80 percent. [40 CFR §§ 64.3(b)(4), 64.6(c) and 60.48b(e)(1)]

5.17.4. A PS1 Field Audit Performance Test shall be conducted no less frequently than quarterly.

5.17.4.1 The calibration error check shall be performed using attenuators as described in ASTM D 6216-98, section 7.5 for applicable standards of 10 to 19 percent opacity.

[40 CFR §§ 64.3(b)(4), 64.6(c), 71.6(a)(3)(i)(B) and (C), 71.6(a)(3)(ii) and 71.6(c)(1)]

5.18. Process and Control Device Monitoring. The permittee shall conduct monitoring as follows:

5.18.1. Install, calibrate, operate and maintain, in accordance with manufacturer specifications, equipment necessary to measure and record:

5.18.1.1 Steam production (lb/hr) – continuous measurement/display, one-hour block averages recorded with at least 90% monthly data capture;

5.18.1.2 Steam pressure (psig) – continuous measurement/display, recorded at least once per month;

5.18.1.3 Steam temperature (°F) – continuous measurement/display, recorded at least once per month;

5.18.1.4 Boiler excess oxygen downstream of the combustion chamber (%) - continuous measurement/display, one-hour block averages recorded with at least 90% monthly data capture;

5.18.1.5 Pressure drop across the multiclone (inches of water) beginning 60 days after permit issuance – continuous measurement/display, recorded at least once per month; and

5.18.1.6 Secondary voltage (volts and kilovolts, respectively), secondary current (amps and milliamps, respectively) and sparking rate for each field of the ESP – continuous measurement/display, one-hour block averages recorded with at least 90% monthly data capture.

5.18.2. At least annually, the permittee shall verify and document the accuracy of the steam production rate monitoring equipment in accordance with manufacturing specifications.

[40 CFR §§ 64.3(b)(4), 64.6(c), 71.6(a)(3)(i)(B) and (C), 71.6(a)(3)(ii) and 71.6(c)(1)]

5.19. The permittee shall ensure that the monitoring equipment required by Conditions 5.17 and 5.18 meets the following performance, operational and maintenance criteria:

5.19.1. Measurement locations that provide for obtaining data that are representative of the emissions or parameters being monitored. [40 CFR § 64.3(b)(1)]

5.19.2. Quality assurance and control practices, considering manufacturer recommendations, that are adequate to ensure the continuing validity of the data. [40 CFR § 64.3(b)(3)]

5.19.3. Maintaining necessary parts for routine repairs of the monitoring equipment. [40 CFR § 64.7(b)]

5.19.4. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), continuous operation of the monitoring equipment

(or collecting data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The permittee shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. [40 CFR § 64.7(c)]

5.19.5. An excursion is defined as a COMS 1-hour block average visible emission value exceeding 6% opacity. [40 CFR §§ 64.1 and 64.6(c)(2)]

5.19.6. An exceedance is defined as any measured emission of PM which exceeds an emission limit specified in Conditions 3.9, 5.3, 5.4 or 5.5. [40 CFR §§ 64.1 and 64.6(c)(2)]

5.20. Upon detecting an excursion or exceedance, the permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable. [40 CFR § 64.7(d)(1)]

5.21. The permittee shall develop and implement a quality improvement plan (QIP) in accordance with 40 CFR § 64.8 if EPA Region 10 determines, pursuant to 40 CFR § 64.7(d)(2), that the permittee has not used acceptable procedures in response to an excursion or exceedance. [40 CFR §§ 64.7(d)(2) and 64.8(a)]

5.22. If the permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the permittee shall promptly notify the permitting authority and, if necessary, submit a proposed modification to the permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. [40 CFR § 64.7(e)]

5.23. The recordkeeping requirements of Condition 3.31 shall apply to monitoring conducted to satisfy Conditions 5.17 through 5.22. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to 40 CFR § 64.8 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions). Instead of paper records, the permittee may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements. [40 CFR § 64.9(b)]

5.24. Continuous NO_X Monitoring. If 12-month rolling NO_X emissions (as calculated pursuant to Condition 5.9 by summing monthly emissions determined in accordance with Conditions 5.9.1 or 5.9.2) equal or exceed 113 tons per year, the permittee shall install, certify, calibrate, maintain and operate a CERMS for measuring and recording the NO_X emission rate (lb/hr) from the boiler. A CERMS includes a NO_X CEMS and a stack flow monitoring system with an automated data acquisition and handling system (DAHS) for measuring and recording NO_X concentration (ppm), stack volumetric gas flow (scfh) and NO_X mass emissions (lb/hr) discharged to the atmosphere from the boiler.

5.24.1. The permittee shall begin operating and recording data from the NO_X CERMS during all periods of operation no later than 180 days after recording 12-month rolling NO_X emissions in excess of 113 tons per year. All periods of boiler operation during which NO_X CERMS is data is unavailable shall be recorded.

5.24.2. The NO_X CERMS shall be designed, installed, calibrated and operated as follows:

5.24.2.1 The NO_X CERMS shall be installed such that representative measurements of the total NO_X emissions from each boiler can be obtained.

5.24.2.2 A minimum of one cycle of operation (sampling, analyzing and data recording) shall be completed for each successive 15-minute period. One-hour average NO_X emission rates (lb/hr) measured by the NO_X CERMS shall be computed from four or more data points equally spaced over each one-hour period except that a one-hour average NO_X emission rate may be computed from two or more data points separated by a minimum of 15 minutes if other data point(s) are unavailable as a result of the performance of calibration, quality assurance or preventive maintenance activities.

5.24.2.3 The NO_X CERMS CEMS span shall be 200 ppm (wet basis). The system shall automatically check the low-level (between 0% and 20% of span) and high-level (between 50% and 100% of span) calibration drifts at least once daily in accordance with the manufacturer's recommended procedure. The system shall, as a minimum, be adjusted whenever either the daily low-level or high-level drift exceeds 2.5% of the span. The system shall allow the amount of excess drift to be quantified and recorded. The system span may be adjusted, when needed to prevent span exceedances from occurring or inadequate measurement accuracy, with prior written approval by EPA Region 10.

5.24.2.4 The NO_X CERMS stack flow monitoring system span shall be 50,000 scfm (wet basis). The system shall automatically check the low-level (between 0% and 20% of span) and high-level (between 50% and 70% of span) calibration drifts at least once daily in accordance with the manufacturer's recommended procedure. The system shall, as a minimum, be adjusted whenever either the daily low-level or high-level drift exceeds 3% of the span. The system shall allow the amount of excess drift to be quantified and recorded. The system span may be adjusted, when needed to prevent span exceedances from occurring or inadequate measurement accuracy, with prior written approval by EPA Region 10.

5.24.3. The permittee shall develop a NO_X CERMS quality assurance plan that includes quality assurance and accuracy determination procedures, methods and schedules similar in scope to Procedure 1 in 40 CFR 60, Appendix F, and Performance Specifications 6 in 40 CFR 60 Appendix B, and applicable specifications and test procedures in 40 CFR

75 Appendices A and B. The RATA must be conducted at least once in every eight calendar quarters and the CGA or RAA may be conducted in up to seven of eight calendar quarters but in no more than seven quarters in succession. Reference Methods 1 through 4 and 7E (except that an NO to NO_2 converter must be used per section 5.1.2 of RM 7E) found in 40 CFR 60, Appendix A, shall be used for determining the relative accuracy in units of lb/hr.

5.24.4. Quarterly NO_X CERMS accuracy determinations shall be performed and recorded in accordance with the quality assurance plan required in Condition 5.24.3. The first quarterly NO_X CERMS accuracy determination shall be performed within 90 days after the NO_X CERMS begins operating and recording data.

5.24.5. The permittee shall sum the hourly emissions to calculate the monthly and rolling 12-month NO_X emissions (tons) from the boiler within 30 days after the end of each month. Except as provided in Conditions 5.24.5.1 and 5.24.5.2, hourly NO_X emissions (lb/hr) for each hour shall be calculated using the following equation:

$$NO_X\ ER = C \times \frac{1.194 \times 10^{-7}\ \text{lb/scf}}{\text{ppmv}} \times Q$$

Where: NO_X ER = NO_X emission rate in units of lb/hr;

C = 1-hour average NO_X concentration as measured in units of ppmv; and

Q = 1-hour stack exhaust flow rate as measured in units of scf/hour.

NO_X concentration (C) and **stack exhaust flow rate** (Q) are measured by the NO_X CERMS.

5.24.5.1 For each hour of boiler operation that any component of the CERMS (either CEMS, stack flow monitoring system or DAHS) is <u>not</u> operational or <u>not</u> certified <u>and</u> the steam production measurement equipment is operational and calibrated, the permittee shall either (1) measure the NO_X emission rate using continuous reference method testing, or (2) calculate NO_X emissions (lb/hr) by multiplying the most recent test-derived emission factor (or 0.421 lb/mlb in the absence of a test-derived emission factor) by the measured boiler steam production rate (mlb/hr).

5.24.5.2 For each hour of boiler operation that any component of the CERMS (either CEMS, stack flow monitoring system or DAHS) is <u>not</u> operational or <u>not</u> certified <u>and</u> the steam production measurement equipment is <u>not</u> operational or <u>not</u> calibrated, the permittee shall either (1) measure the NO_X emission rate using continuous reference method testing, or (2) assume NO_X emissions from the boiler are equal to the product of the most recent test-derived emission factor (or 0.421 lb NO_X/mlb steam in the absence of a test-derived emission factor) and 80 mlb steam/hr.

5.24.5.3 For the purpose of Conditions 5.24.5.1 and 5.24.5.2, the NO_X CERMS is considered certified when the first quarterly accuracy determination, that is acceptable to EPA, is completed.

[40 CFR §§ 71.6(a)(3)(i)(B) and (C), 71.6(a)(3)(ii) and 71.6(c)(1)]

5.25. <u>COMS, Process and Control Device Monitoring During Testing</u>. During each boiler test run required by this permit, the following parameters shall be monitored and recorded:

5.25.1. The average value recorded by each process or control monitoring device required in Condition 5.18.1. For monitoring devices that do not have continuous recordings, the average must consist of no fewer than three values recorded per test run.

5.25.2. During any PM testing, the average opacity recorded during the test by the COMS. Identify any 6-minute average periods that exceed the visible emission limit in Condition 5.5.

[40 CFR §§ 71.6(a)(3)(i)(B) and (C), 71.6(a)(3)(ii) and 71.6(c)(1)]

5.26. Heat Input Tracking. The permittee shall determine monthly heat input to the boiler as follows:

5.26.1. Continuously track and record the boiler's steam generating rate in accordance with Condition 5.18.1.1 and total each month's steam production (mlb/month);

5.26.2. Employ a FHISOR of 1.520 MMBtu/mlb to calculate monthly heat input to the boiler until testing is performed pursuant to Condition 5.13; and

5.26.3. Once a test-derived FHISOR (MMBtu/mlb) has been determined pursuant to Condition 5.13, monthly heat input shall be determined by multiplying the monthly steam production (mlb steam/month) by the most recent FHISOR (MMBtu/mlb).

[40 CFR §§ 71.6(a)(3)(i)(B) and (C), 71.6(a)(3)(ii) and 71.6(c)(1)]

5.27. Electrostatic Precipitator Inspection. At least once each year and whenever the boiler is shut down for maintenance, the permittee shall inspect the ESP for physical degradation that could affect the performance of the control devices.

5.27.1. At a minimum, the permittee shall check the following components of the ESP for damage that would reduce its efficiency.

5.27.1.1 Discharge electrodes (wires).

5.27.1.2 Collection electrodes (plates).

5.27.1.3 Electrode alignment.

5.27.1.4 Rapper mechanisms for both the discharge electrodes and collection electrodes.

5.27.1.5 Shell integrity (e.g., insulation and leaks).

5.27.1.6 Transformer-rectifiers (TR) sets.

5.27.2. The permittee shall record in a log, that is retained on-site and available to EPA inspectors for at least five years, the results of required inspections and subsequent repair activities conducted on the ESP. The log shall contain the date of inspection, the identity of the inspector, the results of each inspection, and the date and nature of any corrective action taken.

[40 CFR §§ 71.6(a)(3)(i)(B) and (C), 71.6(a)(3)(ii) and 71.6(c)(1)]

5.28. Records Retention. The permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this permit or 40 CFR Part 60 Subparts A and Db recorded in a permanent form suitable for inspection.

[40 CFR § 60.7(f), 40 CFR §§ 71.6(a)(3)(i)(B) and (C); 71.6(a)(3)(ii); 71.6(c)(1)]

5.29. NSPS Records of Opacity. The permittee shall maintain records in accordance with 40 CFR § 60.11(e). [40 CFR § 60.49b(f)]

5.30. NSPS Records of Startup, Shutdown and Malfunction. The permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the boiler; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative. [40 CFR § 60.7(b)]

PH5 Reporting Requirements

5.31. Notifications and Reports Related to Particulate Matter and Opacity Testing and Monitoring System Certification. The permittee shall furnish the EPA written notification as follows.

5.31.1. The permittee shall submit notification of the anticipated date upon which demonstration of the continuous opacity monitoring system (COMS) performance evaluation commences in accordance with 40 CFR § 60.13(c). Notification shall be postmarked not less than 30 days prior to such date. [40 CFR § 60.7(a)(5)]

5.31.2. The permittee shall submit notification of the anticipated date for conducting the opacity observations required by 40 CFR § 60.11(e)(1). The notification may also include a request for EPA to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date. [40 CFR § 60.7(a)(6)]

5.31.3. If the permittee elects to use the COMS to determine compliance as allowed by 40 CFR § 60.11(e)(5), the permittee shall submit notification that the COMS data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR § 60.8 in lieu of 40 CFR Part 60 Appendix A Method 9 observation data. This notification shall be postmarked not less than 30 days prior to the date of the performance test. [40 CFR § 60.7(a)(7)]

5.31.4. The permittee shall provide EPA at least 30 days prior notice of any performance test to afford EPA the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay in conducting the scheduled performance test, the owner or operator of each boiler shall notify EPA as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with EPA by mutual agreement. [40 CFR § 60.8(d)]

5.31.5. The permittee shall submit to EPA, within 60 days after any performance test, three copies of the data from the performance test and the performance evaluation of the opacity monitor using the applicable performance specifications in 40 CFR Part 60 Appendix B or this permit as applicable. [40 CFR §§ 60.49b(b), 60.11(e)(4), 60.8(a), 71.6(a)(3)(i)(B) and (C); 71.6(a)(3)(ii); 71.6(c)(1)]

5.31.6. The permittee shall submit to EPA with the test report referred to in Condition 5.31.5 any data required by Condition 5.18.1to be collected, analyzed or calculated during any performance test. [40 CFR §§ 71.6(a)(3)(i)(B) and (C); 71.6(a)(3)(ii); 71.6(c)(1)]

5.31.7. The permittee shall report opacity in accordance with 40 CFR § 60.11(e). [40 CFR § 60.11(e)]

5.32. Opacity Reporting. The permittee shall report as follows:

5.32.1. The permittee is required to submit semiannual excess emission reports for any excess emission which occurred during the reporting period. For the purpose of 40 CFR § 60.43b, excess emissions are defined as all 6-minute periods during which the average

opacity exceeds the opacity standards under 40 CFR § 60.43b(f). The reporting period for the reports required under this condition is each 6-month period. All reports shall be submitted to EPA and shall be postmarked by the 30th day following the end of the reporting period. [40 CFR §§ 60.49b(h) and (w)]

5.32.2. The permittee shall submit excess emissions and monitoring systems performance reports and/or summary report forms to EPA semiannually, except when EPA, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

5.32.2.1 The magnitude of excess emissions computed in accordance with 40 CFR § 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. And the process operating time during the reporting period.

5.32.2.2 Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of each boiler. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

5.32.2.3 The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

5.32.2.4 When no excess emissions have occurred or the continuous opacity monitoring systems have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

[40 CFR § 60.7(c)]

5.32.3. The summary report form referred to in Condition 5.32.2 shall contain the information and be in the format shown in figure 1 of 40 CFR § 60.7 unless otherwise specified by EPA. One summary report form shall be submitted for each pollutant (opacity). [40 CFR § 60.7(d)]

5.32.4. If the total duration of excess emissions for the reporting period is less than one percent of the total operating time for the reporting period and COMS downtime for the reporting period is less than five percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR § 60.7(c) need not be submitted unless requested by EPA. [40 CFR § 60.7(d)]

5.32.5. If the total duration of excess emissions for the reporting period is one percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is five percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR § 60.7(c) shall both be submitted. [40 CFR § 60.7(d)]

5.33. Compliance Assurance Monitoring Reporting for FARR and NSPS Particulate Matter Limits. The reports required by Condition 3.47 and 3.48 shall include the following:

5.33.1. Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions and exceedances, as applicable, and the corrective actions taken;

5.33.2. Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

5.33.3. A description of the actions taken to implement a QIP during the reporting period as specified in § 64.8. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

[40 CFR § 64.9(a)(2)]

5.34. NO_X Reporting. The permittee shall report as follows:

5.34.1. Postmarked at least 30 days prior to any NO_X emission factor derivation test, the permittee shall submit three copies of a test plan consistent with Condition 3.24.

5.34.2. Postmarked within 60 days after completion of any NO_X emission factor derivation test, the permittee shall submit three copies of a written report of results of the test.

5.34.3. Postmarked at least 30 days prior to the NO_X CERMS beginning to operate and record data, the permittee shall submit three copies of the quality assurance plan for the NO_X CERMS required in Condition 5.24.3.

5.34.4. At least 30 days prior to any NO_X CERMS accuracy determination required in Condition 5.24.4, the permittee shall submit notification of the planned date for performing the determination.

5.34.5. Within 60 days after completing the determination, the permittee shall submit three copies of a written report of the results of any NO_X CERMS accuracy determinations.

5.34.6. Within 48 hours after discovery, the permittee shall report to EPA, by telephone or facsimile that the calculated rolling 12-month NO_X emission rate has exceeded the 126 ton-per-year NO_X emission limit specified in Condition 5.9.

5.34.7. With each six-month monitoring report required in Condition 3.47, the permittee shall submit a semiannual NO_X emissions report that documents all time periods for the previous six-month reporting period when the NO_X CERMS data was unavailable and for each such time period and include the raw data and calculations used to report NO_X emissions along with the reason the NO_X CERMS data was unavailable.

5.34.8. Once each year, on or before April 1, the permittee shall, along with the annual registration required in Condition 3.46, submit to EPA a report containing the twelve monthly rolling 12-month emissions calculations for the previous calendar year.

5.34.8.1 The report shall contain a description of all emissions estimating methods used, including emission factors and their sources, assumptions made and production data.

[40 CFR §§ 71.6(a)(3)(i)(B) and (C); 71.6(a)(3)(ii); 71.6(c)(1)]

5.35. VOC Reporting. The permittee shall report as follows:

5.35.1. Postmarked at least 30 days prior to any VOC emission factor derivation test, the permittee shall submit three copies of a test plan consistent with Condition 3.24.

5.35.2. Postmarked within 60 days after completion of any VOC emission factor derivation test, the permittee shall submit three copies of a written report of results of the test.

5.35.3. Within 48 hours after discovery, the permittee shall report to EPA, by telephone or facsimile that the calculated rolling 12-month VOC emission rate has exceeded the 21.5 ton-per-year VOC emission limit specified in Condition 5.10.

5.35.4. Once each year, on or before April 1, the permittee shall, along with the annual registration required in Condition 3.46, submit to EPA a report containing the twelve monthly rolling 12-month emissions calculations for the previous calendar year.

5.35.4.1 The report shall contain a description of all emissions estimating methods used, including emission factors and their sources, assumptions made and production data.

[40 CFR §§ 71.6(a)(3)(i)(B) and (C); 71.6(a)(3)(ii); 71.6(c)(1)]

6. Unit-Specific Requirements – KLN-N (Nardi Lumber Kilns)

KLN-N Emission Limits and Work Practice Requirements

6.1. Particulate matter emissions from the stack(s) of this emission unit shall not exceed an average of 0.23 grams per dry standard cubic meter (0.1 grains per dry standard cubic foot) during any three-hour period.

6.1.1. Compliance with the particulate matter limit is determined using EPA Reference Method 5 (see 40 CFR part 60, appendix A).

[40 CFR §§ 49.125(d)(3) and (e)]

6.2. The maximum one-hour block average dry bulb temperature (ºF) of heated air entering each lumber stack within KLN-N as determined pursuant to Condition 4.20 shall not exceed 200°F. [Permit No. R10NT500401]

7. Unit-Specific Requirements – KLN-W (Wellons Lumber Kilns)

KLN-W Emission Limits and Work Practice Requirements

7.1. Particulate matter emissions from the stack(s) of this emission unit shall not exceed an average of 0.23 grams per dry standard cubic meter (0.1 grains per dry standard cubic foot) during any three-hour period.

7.1.1. Compliance with the particulate matter limit is determined using EPA Reference Method 5 (see 40 CFR part 60, appendix A).

[40 CFR §§ 49.125(d)(3) and (e)]

7.2. Volatile organic compound emissions from KLN-W shall not exceed 22.0 tpy as determined on a rolling 12-month basis by calculating the emissions (tons) for each month and adding the emissions (tons) calculated for the previous eleven months. Monthly KLN-W emissions (tons) shall be determined by multiplying the recorded monthly specie-specific and temperature-specific dry lumber production rates (mbf/month) determined pursuant to Condition 4.19 by the corresponding specie-specific and temperature-specific VOC emission factors (lb/mbf) presented in Appendix C of this permit, summing, and dividing by 2000 lb/ton.

[Section 304(f)(4) of the Federal Clean Air Act and 40 CFR § 71.6(b)]

7.3. The maximum one-hour block average dry bulb temperature (ºF) of heated air entering each lumber stack within KLN-W as determined pursuant to Condition 4.20 shall not exceed 200°F. [Permit No. R10NT500401]

8. Unit-Specific Requirements – CYC (Wood Residue Cyclones)

CYC Emission Limits and Work Practice Requirements

8.1. Particulate matter emissions from the stack(s) of this emission unit shall not exceed an average of 0.23 grams per dry standard cubic meter (0.1 grains per dry standard cubic foot) during any three-hour period.

8.1.1. Compliance with the particulate matter limit is determined using EPA Reference Method 5 (see 40 CFR part 60, appendix A).

[40 CFR §§ 49.125(d)(3) and (e)]

9. Unit-Specific Requirements – MNFA (Miscellaneous Non-Fugitive Activities)

MNFA Emission Limits and Work Practice Requirements

9.1. Particulate matter emissions from the stack(s) of this emission unit shall not exceed an average of 0.23 grams per dry standard cubic meter (0.1 grains per dry standard cubic foot) during any three-hour period.

9.1.1. Compliance with the particulate matter limit is determined using EPA Reference Method 5 (see 40 CFR part 60, appendix A).

[40 CFR §§ 49.125(d)(3) and (e)]

Appendix A: HAP Emission Factors for Lumber Drying

Species	Max Kiln Temp[1] °F	Total HAP lb/mbf	Methanol[2] lb/mbf	Formaldehyde[2] lb/mbf	Acetaldehyde lb/mbf	Propionaldehyde lb/mbf	Acrolein lb/mbf
Non-Resinous Softwood Species							
White Fir[3]	≤200	0.2107	0.1480	0.0034	0.0550	0.0018	0.0026
	>200	0.4956	0.4200	0.0163			
Western Hemlock	≤200	0.2921	0.1484	0.0016	0.1378	0.0018	0.0026
	>200	0.3661	0.2196	0.0044			
Western Red Cedar	≤200	0.2939	0.1484	0.0034	0.1378	0.0018	0.0026
	>200	0.5784	0.4200	0.0163			
Resinous Softwood Species (Non-Pine Family)							
Douglas Fir	≤200	0.1409	0.0690	0.0019	0.0682	0.0007	0.0011
	>200	0.1913	0.1170	0.0043			
Engelmann Spruce	≤200	0.0640	0.0250	0.0013	0.0360	0.0007	0.0010
	>200	0.1201	0.0780	0.0044			
Larch	≤200	0.1409	0.0690	0.0019	0.0682	0.0007	0.0011
	>200	0.1914	0.1170	0.0044			

Appendix A: HAP Emission Factors for Lumber Drying

Species	Max Kiln Temp[1] °F	Total HAP lb/mbf	Methanol[2] lb/mbf	Formaldehyde[2] lb/mbf	Acetaldehyde lb/mbf	Propionaldehyde lb/mbf	Acrolein lb/mbf
Resinous Softwood Species (Pine Family)							
Lodgepole Pine	≤200	0.1166	0.0628	0.0041	0.0420	0.0032	0.0045
	>200	0.1166	0.0628	0.0041			
Ponderosa Pine	≤200	0.1271	0.0740	0.0034	0.0420	0.0032	0.0045
	>200	0.2029	0.1440	0.0092			
Western White Pine	≤200	0.1271	0.0740	0.0034	0.0420	0.0032	0.0045
	>200	0.2029	0.1440	0.0092			

[1] Maximum kiln temperature reflects heated air entering load of lumber.

[2] Because methanol and formaldehyde emissions appear to be dependent upon drying temperature, separate values are calculated for low and high-temperature drying.

[3] White fir in this context refers to any one of several species of true fir grown in the West. The collection of timber commonly referred to as "white fir" includes the following species: white fir, grand fir, noble fir and subalpine fir.

Appendix B: HAP Emission Factors for Biomass Boiler

Hazardous Air Pollutant	Emission Factor lb/MMBtu
Antimony Compounds	7.90E-06
Arsenic Compounds (including arsine)	2.20E-05
Beryllium Compounds	1.10E-06
Cadmium Compounds	4.10E-06
Chromium Compounds (including hexavalent)	2.10E-05
Cobalt Compounds	6.50E-06
Lead Compounds (not elemental lead)	4.80E-05
Manganese Compounds	1.60E-03
Mercury Compounds	3.50E-06
Nickel Compounds	3.30E-05
Phosphorus	2.70E-05
Selenium Compounds	2.80E-06
Chlorine	7.90E-04
Hydrochloric acid (hydrogen chloride)	2.26E-03
Acetaldehyde	8.30E-04
Acetophenone	3.20E-09
Acrolein	4.00E-03
Benzene	4.20E-03
Bis(2-ethylhexyl)phthalate (DEHP)	4.70E-08
Carbon tetrachloride	4.50E-05
Chlorobenzene	3.30E-05
Chloroform	2.80E-05
Dibenzofurans	1.87E-09
2,4-Dinitrophenol	1.80E-07
Ethyl benzene	3.10E-05
Ethylene dichloride (1,2-Dichloroethane)	2.90E-05
Formaldehyde	4.40E-03
Methyl bromide (Bromomethane)	1.50E-05
Methyl chloride (Chloromethane)	2.30E-05
Methyl chloroform (1,1,1-trichloroethane)	3.10E-05
Methylene chloride (Dichloromethane)	2.90E-04
Naphthalene	9.70E-05
4-Nitrophenol	1.10E-07
Pentachlorophenol	5.10E-08

Appendix B: HAP Emission Factors for Biomass Boiler

Hazardous Air Pollutant	Emission Factor lb/MMBtu
Phenol	5.10E-05
Polychlorinated biphenyls (PCB)	8.15E-09
Polycyclic Organic Matter (POM)	1.27E-04
Propionaldehyde	6.10E-05
Propylene dichloride (1,2-Dichloropropane)	3.30E-05
Styrene	1.90E-03
2,3,7,8-Tetrachlorodibenzo-p-dioxin	8.60E-12
Tetrachloroethylene (Tetrachloroethene)	3.80E-05
Toluene	9.20E-04
Trichloroethylene (Trichloroethene)	3.00E-05
2,4,6-Trichlorophenol	2.20E-08
Vinyl chloride	1.80E-05
Xylenes (inlc isomers and mixtures)	2.50E-05

Appendix C: VOC Emission Factors for Lumber Drying

Species	Maximum Kiln Temperature[1] (°F)	WPP1 VOC[2,3] (lb/mbf)
Non-Resinous Softwood Species		
White Fir[4]	≤200	0.8388
	>200	1.0902
Western Hemlock	≤200	0.5253
	>200	0.6615
Western Red Cedar	≤200	0.3631
	>200	1.1453
Resinous Softwood Species (Non-Pine Family)		
Douglas Fir	≤200	1.1576
	>200	1.6969
Engelmann Spruce	≤200	0.1775
	>200	0.2161
Larch	≤200	1.1576
	>200	1.6969
Resinous Softwood Species (Pine Family)		
Lodgepole Pine	≤200	1.5293
	>200	1.5293
Ponderosa Pine	≤200	2.3450
	>200	3.8087
Western White Pine	≤200	2.8505
	>200	3.8087

[1] Maximum kiln temperature reflects heated air entering load of lumber.

[2] VOC emissions have been approximated consistent with EPA's Interim VOC Measurement Protocol for the Wood Products Industry - July 2007 (WPP1 VOC). Employing WPP1 VOC underestimates emissions when the mass-to-carbon ratio of unidentified VOC exceeds that of propane. Ethanol and acetic acid are examples of compounds that contribute to lumber drying VOC emissions (for some species more than others), and both have mass-to-carbon ratios exceeding that of propane.

[3] Because VOC emissions appear to be dependent upon drying temperature, separate values are calculated for low and high-temperature drying.

[4] White fir in this context refers to any one of several species of true fir grown in the West. The collection of timber commonly referred to as "white fir" includes the following species: white fir, grand fir, noble fir and subalpine fir.

United States Environmental Protection Agency
Region 10, Office of Air, Waste and Toxics
AWT-150
1200 Sixth Avenue, Suite 900
Seattle, Washington 98101-3140

Permit Number: R10T5010100
Issued: September 30, 2014
Effective: October 31, 2014
Expiration: September 30, 2019
Replaces: R10T5010001
AFS Plant I.D. Number: 41-065-00034

Statement of Basis

Title V Air Quality Operating Permit
Renewal No. 1

Permit Writer: Dan Meyer

Warm Springs Forest Products Industries

Warm Springs Reservation
Warm Springs, Oregon

Purpose of Permit and Statement of Basis

Title 40 Code of Federal Regulations Part 71 establishes a comprehensive air quality operating permit program under the authority of Title V of the 1990 amendments to the federal Clean Air Act. The air quality operating permit is an enforceable compilation of all of the applicable air pollution requirements that apply to an existing affected air emissions source. The permit is developed via a public process, may contain additional new requirements to improve monitoring of existing requirements, and contains procedural and prohibitory requirements related to the permit program itself. The permit is valid for five years and may be renewed.

This document, the statement of basis, summarizes the legal and factual basis for the permit conditions in the air quality operating permit to be issued to Warm Springs Forest Products Industries (referred to herein as WSFPI, facility, source, or permittee). Unlike the air quality operating permit, this document is not legally enforceable. This statement of basis summarizes the emitting processes at the facility, air emissions, permitting and compliance history, the statutory or regulatory provisions that relate to the subject facility, and the steps taken to provide opportunities for public review of the permit. The permittee is obligated to follow the terms of the permit. Any errors or omissions in the summaries provided here do not excuse the permittee from the requirements of the permit.

Table of Contents

1. EPA Authority to Issue Title V Permits

On July 1, 1996, EPA adopted regulations (see 61 Federal Register (FR) 34202) codified at 40 Code of Federal Regulations (CFR) Part 71 setting forth the procedures and terms under which the Agency would administer a federal operating permit program. These regulations were updated on February 19, 1999 (64 FR 8247) to incorporate EPA's approach for issuing federal operating permits to affected stationary sources in Indian Country.

As described in 40 CFR 71.4(a), EPA will implement a Part 71 program in areas where a state, local, or Tribal agency has not developed an approved Part 70 program. Unlike states, Indian Tribes are not required to develop operating permit programs, though EPA encourages Tribes to do so. See, for example, Indian Tribes: Air Quality Planning and Management (63 FR 7253, February 12, 1998) (also known as the "Tribal Authority Rule"). Therefore, within Indian Country, EPA will administer and enforce a Part 71 federal operating permit program for stationary sources until the governing Indian Tribe receives EPA's approval to administer its own operating permit program.

2. Facility Information

2.1 Location

The WSFPI facility is located on the east side of Warm Springs, Oregon on the Warm Springs Reservation, bounded by Highway 26, the Deschutes River and Shitike Creek. The facility is located within the exterior boundaries of the 1855 Warm Springs Reservation and is in Indian Country as defined in 40 CFR Part 71.

2.2 Warm Springs Reservation

The WSFPI facility is located on the Warm Springs Reservation located in north central Oregon. The reservation was established by the Treaty of June 25, 1855 (12 Stat. 963), by which The Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes) ceded to the United States their aboriginal title to approximately 10 million acres in north-central Oregon and reserved for their own use forever the Warm Springs Reservation. The reservation is considered to be Indian Country, as defined in 40 CFR Part 71.

The Tribes are a federally recognized Indian Tribe having a Constitution and By-laws and federal Corporate Charter adopted pursuant to the Indian Reorganization Act of 1934. The Reservation is governed by an eleven-member Tribal Council consisting of the hereditary Chiefs of the three tribes comprising the Confederated Tribes and eight members elected from the three districts on the reservation, which represent traditional tribal areas.

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2.4 Facility Description

The primary operation at the facility is the production of dimensional lumber from raw logs. The WSFPI facility has debarkers and saws, kilns for drying lumber, a planer, and a hog fuel fired boiler to supply steam to the kilns. The site comprises 34 acres and includes process areas, a log yard, shops, offices, open and covered storage, and warehouse areas. There are no chemical wood preservative or gluing operations. Logs are received and stored in the log yard. The process of cutting the logs into lumber includes debarking, sawing, chipping, kiln drying, planing, and packaging for shipping.

The byproducts of lumber manufacturing are sawdust, wood chips, planer shavings, and hog fuel. These byproducts may be burned in the hog fuel (wood-waste) boiler or stored in bins until the material is sold and transferred off-site. One hog fuel boiler is used to provide steam for the drying of rough green lumber in the drying kilns while also producing steam to produce electricity in three steam turbine-powered 3-megawatt capacity generators. The electricity produced is used on-site. It is not currently economical for WSFPI to generate electricity for sale, and capital improvements to the site would be necessary to supply electricity to the regional power supply grid.

The Title V permit is being issued solely to WSFPI; a wholly owned business enterprise of the Tribes. WSFPI is both the owner and sole operator of the facility. WSFPI was not always the sole operator of the facility. Vanport International Inc. (Vanport) recently managed and operated the facility pursuant to a written agreement with WSFPI. That written agreement was terminated January 1, 2014, and written agreements entered into by the parties thereafter have not provided Vanport similar authority. This means that beginning January 1, 2014, Vanport no longer has any control over any operations at the facility. WSFPI is now solely responsible for complying with any Clean Air Act (CAA) obligations applicable to the facility.

Another enterprise owned by the Tribes, Warm Springs Composite Products (WSCP), is co-located at the WSFPI plant site. WSCP manufactures “fireproof”-core (refractory) materials, fire-door components and door-jamb systems, and they perform pre-certification (fire) door testing. The manufacturing process at the WSCP facility is assigned to SIC code group 3272 (Concrete Products, Except Block and Brick) which is different from WSFPI’s 2421 primary SIC code. Although WSCP uses a fraction of the steam from the WSFPI boiler, no other materials are transferred between the facilities. Because WSFPI and WSCP have different SIC codes and are not in a support relationship, they are not considered a single source for 40 CFR part 52 PSD permitting purposes. The two operations, however, are considered one source under CAA Section 112, i.e., EPA’s NESHAP or maximum achievable control technology “MACT” program for reducing HAP emissions from stationary sources. WSCP’s potential HAP emissions are estimated to be around 0.04 tons per year.

Title V permit program applicability is not triggered due to HAP emissions given that combined potential emissions from WSFPI and WSCP are less than major source thresholds. Title V permit program applicability in this case turns on each source’s emissions of non-HAP subject to regulation. WSCP’s potential emissions of non-HAP subject to regulation are less than major source thresholds, and thus WSCP is not subject to Title V permit program in and of itself. This could change over time, however, if the relationship between the facilities changes. In contrast, WSFPI is a major source of non-HAP subject to regulation as illustrated by information presented later in this document.

The air pollution emission units and control devices that exist at WSFPI are listed in Table 2-1 below by emission unit identification (EU ID). None of the emission units vent through a stack shared with another emission unit. Installation dates for each emission unit are listed because they are important in determining applicability of federal PSD, NSPS and MACT standards (see further discussion in Section 4). Capacities are listed for several emission units based on the best information available from the applicant. Those control devices that are required by rule or this permit are so noted.

Table 2-1 – Emission Units & Control Devices

EU ID	Emission Unit Description	Control Device[1]
PH 5	*Biomass Boiler*. Wellons Model No. NB234. Serial No. B2329-0503. Two-cell pile-burning design with automatic rotating grates and overfeed fuel delivery. Combustion air introduced below and above grates. Oxygen trim system. Heat input capacity 131 million Btu/hr (MMBtu/hr). Maximum steam production 80,000 lb/hr at 250 psig and 750ºF. Generates only superheated steam. Supplies steam to kilns (via desuperheater), to non-extractive steam turbine electric generating units and to WSCP. Permit authorizing construction issued May 4, 2005. Startup December 27, 2005.	1. Wellons multiclone. Model No. W144. Serial No. B2329-1226. 2. Wellons electrostatic precipitator (ESP). Model No. 2W-092-1422. Serial No. B2320-2425. Part of original boiler installation.
KLN-N	*Nardi Lumber Drying Kilns*. Indirectly heated. Five single-track Nardi kilns (No.'s 1-5) installed 1997. Annual capacity of approximately 77 million board feet (mmbf) with each track contributing 15.37 mmbf.	None
KLN-W	*Wellons Lumber Drying Kilns*. Indirectly heated. Two double-track Wellons kilns (No's 6a – 7b) installed 2000. Annual capacity of approximately 61 mmbf with each track contributing 15.37 mmbf.	None
CYC	*Wood Residue Cyclones*. Six cyclones (CYC1 through CYC6) employed to capture pneumatically conveyed wood residue and deposit into storage bins for later sale and distribution off-site or consumption by boiler on-site. The six capture devices are process equipment and not air pollution control devices (APCD).[2]	None
MNFA	*Miscellaneous Non-Fugitive Activities.* Activities occurring inside a building that generate wood residue that is not pneumatically conveyed to a product recovery device.	Inside building
MFA	*Miscellaneous Fugitive Activities.* Activities occurring outside a building or storage structure that generate, transport or store wood residue.	None
PT	*Plant traffic*. Fugitive emissions including forklifts and log trucks (paved and unpaved roads).	Watering

[1] The multiclone and ESP are required to be used by this permit.

[2] See November 27, 1995 letter from EPA's David Solomon to Intel's Timothy J. Mohin. Although CYC is considered process equipment (as opposed to APCD) for the purpose of calculating potential emissions, CYC is not considered a "process source" in the context of the Federal Air Rules for Reservations (FARR) as CYC does not cause a change in material by either chemical or physical means. See definition of "process source" at 40 CFR § 49.123.

An emission unit or activity qualifies as an insignificant emission unit (IEU) if it is an activity type listed in 40 CFR 71.5(c)(11)(i) or emits less than 2 tons per year of any regulated air pollutant excluding HAPs [40 CFR 71.5(c)(11)(ii)(A)] and less than 1000 pounds per year of any HAP or the de minimis HAP level established under Section 112(g), whichever is lower [40 CFR 71.5(c)(11)(ii)(B)]. WSFPI has listed in its

renewal application the same IEUs from its previous Title V permit, and those IEUs are listed in Table 2-2 below. EPA has added another; the filing room exhaust.

Table 2-2 – Insignificant Emission Units

EU ID	Emission Unit Description
IEU-1	18 Mobile sources
IEU-2	1 Air conditioning units
IEU-3	1 Heating units used for human comfort
IEU-4	Consumer use of office equipment and products
IEU-5	Janitorial services and consumer use of janitorial products
IEU-6	1 Internal combustion engine used for landscaping purposes
IEU-7	General facility maintenance
IEU-8	Filing room exhaust - clean up cyclone.

2.5 Local Air Quality and Attainment Status

Central Oregon, including the Warm Springs Reservation, either attains the national ambient air quality standard (NAAQS) for all criteria pollutants or is unclassified. An area is unclassifiable when there is insufficient monitoring data. The only monitoring data representative of the Warm Springs Reservation that can be compared to the PM_{10} NAAQS is data collected at the National Air Toxics Trend Site in La Grande, Oregon. The most recent three-years of data from this site show that the PM_{10} design value at this location is substantially below the NAAQS. The only monitoring data representative of the Warm Springs Reservation that can be compared to the $PM_{2.5}$ NAAQS is data collected at the State of Oregon ambient air monitoring site in Pendleton. The $PM_{2.5}$ design values for this site have been steadily decreasing since 2004, and the most recent three-years of data from this site show that the $PM_{2.5}$ design value at this location is substantially below the NAAQS.

2.6 Permitting, Construction and Compliance History

The subject facility has been operating as a wood products facility since the 1940s. The Tribes purchased the Wilson Lumber Company facility in 1967 to form WSFPI. At that time the facility consisted of two sawmills, a stud mill, plywood mill (veneer peeler, dryers, and presses), and two steam turbines for electricity generation. In the early 1970s the company purchased and installed an electricity generating system composed of three 3-megawatt-capacity steam turbines and two power boilers (#3 & #4) and decommissioned two existing steam turbines.

A Coe veneer dryer was installed in 1983. In 1989 the existing stud mill was shut down. In 1990 a small-log mill was constructed. In 1991 the existing plywood mill was shutdown and in 1992 the existing large-log mill was shutdown. In 1997, five Nardi single track lumber drying kilns were installed and six existing kilns were torn down. In 1998 the small log mill was modified to allow milling of large logs (up to 3 feet diameter logs). In 2000 the company installed two Wellons double track lumber drying kilns.

There are no records in EPA files indicating that any applicability determinations were made by EPA or any other permitting authority for the projects described above. EPA has not drawn any conclusions regarding compliance with past permitting requirements at this facility and no enforcement shield is implied or granted.

In 2005, the company installed and began operating a hog fuel-fired Wellons 80,000 lb/hr steam boiler after EPA Region 10 issued a Title V permit limiting the net emissions increase from the project to less

than PSD significant thresholds for nitrogen oxides (NO_X) and volatile organic compounds (VOC). The May 4, 2005 Title V permit (No. R10T5010000) required WSFPI to shut down all existing boilers while limiting emissions from the Wellons boiler and two double track lumber drying kilns.

In 2007, WSFPI voluntarily requested EPA Region 10 to limit its HAP emissions to less than major source thresholds so as to avoid becoming subject to the Plywood and Composite Wood Products MACT. The September 24, 2007 non-Title V permit (No. R10NT500400) required WSFPI to limit annual HAP emissions to less than 9 tons individually and to less than 24 tons combined.

In 2008, EPA Region 10 issued another non-Title V permit. An October 10, 2008 non-Title V permit (No. R10NT500300) authorized the construction of another boiler while limiting the net emissions increase from the project to less than PSD significant thresholds for NO_X and VOC. At the same time, EPA Region 10 issued a significant modification to the 2005 Title V permit (No. R10T5010001) to primarily incorporate new requirements established by the non-Title V permit. The Title V significant modification also addressed the creation of Warm Springs Biomass Project LLC, a new operating division of the Tribes. Lastly, the Title V significant modification revised some requirements that were created in the original Title V permit.

On October 26, 2009, EPA Region 10 received from WSFPI a timely Title V permit renewal application. While processing that application, EPA Region 10 received a May 28, 2013 WSFPI request to terminate non-Title V permit No. R10NT500300 as WSFPI no longer intends to construct another boiler. In August 2013, EPA Region 10 simultaneously proposed to issue a Title V permit renewal and terminate non-Title V permit No. R10NT500300. EPA Region 10 terminated non-Title V permit No. R10NT500300 on September 30, 2013. The proposal to renew the Title V permit, however, was not finalized as EPA Region 10 subsequently learned that Vanport, listed as permittee along with WSFPI, was intending to discontinue its role as operator of the facility. Renewing the Title V permit with WSFPI as the sole permittee would require a separate permitting action.

In October 2012, WSFPI submitted to EPA Region 10 a PSD applicability analysis for proposed activities related to boiler PH5 improvements funded by the American Recovery and Reinvestment Act of 2009 (ARRA). There are no records in EPA files indicating that any applicability determination was made by EPA for the ARRA-funded physical change to boiler PH5. Other activities in the same general time period (2013) funded by ARRA include the restoration of a steam turbine or turbines, construction of a hog fuel storage shed and conveyors, and the construction of an air knife to reclaim wood fuel. EPA has not drawn any conclusions regarding compliance with permitting requirements for the aforementioned ARRA-funded activities, and no enforcement shield is implied or granted. The activities were completed before the end of 2013.

Today, EPA Region 10 is simultaneously proposing to renew the expired Title V permit and revise non-Title V permit No. R10NT500400. As described more fully in the accompanying non-Title V proposal, the non-Title V permit is largely being revised to strengthen its practical enforceability. Aside from changes to the non-Title V permit requirements, the proposed Title V permit looks much like the one proposed in August 2013 except that only WSFPI is listed as permittee.

A chronological summary of permit activities for WSFPI is presented in Table 2-3 below.

Table 2-3 – CAA Permitting History

Date	Permit No.	Action
05/04/05	R10T5010000	EPA issues initial Title V permit that limits emissions increase to less than PSD significant threshold levels for construction of boiler PH5.
09/24/07	R10NT500400	EPA issues non-Title V permit to limit HAP emissions to less than major source threshold levels to avoid Plywood and Composite Wood Products MACT and any other major source MACT to come.
10/10/08	R10NT500300	EPA issues non-Title V permit to limit emissions increase to less than PSD significant threshold levels for construction of another boiler.
10/10/08	R10T5010001	EPA issues significant modification to initial Title V permit to primarily address R10NT500300.
12/02/08 – 12/02/09	R10T5010100	Title V permit renewal application due to EPA.
10/26/09	R10T5010100	EPA receives Title V permit renewal application.
05/02/10	R10T5010001	Title V permit expires but is administratively extended because WSFPI submitted a timely permit renewal application.
05/28/13	R10NT500300	EPA receives request to terminate non-Title V permit.
07/26/13	R10T5010100 & R10NT500300	Pre-draft Title V permit renewal and non-Title V permit termination is sent to WSFPI and Warm Springs Tribe for initial review.
08/21/13 – 09/20/13	R10T5010100 & R10NT500300	Public comment period for draft Title V permit renewal and non-Title V permit termination.
09/30/13	R10NT500300	EPA terminates non-Title V permit.
08/11/14	R10T5010100 & R10NT500401	Pre-draft Title V permit renewal and non-Title V permit revision is sent to WSFPI and Warm Springs Tribe for initial review.
08/27/14 – 09/25/14	R10T5010100 & R10NT500401	Public comment period for draft Title V permit renewal and non-Title V permit revision.

EPA inspected the facility on various occasions during the prior permit term. There is no record of any notice of violation having been issued to WSFPI for CAA violations. A summary of the compliance issues is presented in Table 2-4 below.

Table 2-4 – Summary of CAA Inspection Findings

Inspection Date	Potential Compliance Issues
8/10/2006	• Failure to submit timely payment of Title V permit fee. • Failure to submit record of annual emissions resulting from drying of hemlock and white fir lumber in kilns.

Inspection Date	Potential Compliance Issues
	• Failure to conduct quarterly sampling and analysis of fuel to determine hydrogen chloride emission factor resulting from hog fuel combustion. • Failure to monitor and record boiler PH5 ESP operating parameters. • Failure to maintain a log of boiler PH5 ESP inspections. • Failure to record the type and amount of fuel combusted in boiler PH5. • Failure to notify EPA of boiler PH5 COMS performance evaluation. • Failure to limit boilers' hourly steam production to less than 80,000 lb (24-hr average) on 47 occasions.
07/31/2008	• Failure to conduct an annual survey and draft a plan for minimizing fugitive particulate matter emissions. • Failure to conduct quarterly sampling and analysis of fuel to determine hydrogen chloride emission factor resulting from hog fuel combustion. • Failure to maintain a log of boiler PH5 ESP inspections. • Failure to record the type and amount of fuel combusted in boiler PH5. • Failure to measure boiler PH5 average fuel feed rate during a stack test. • Failure to maintain a record of boiler PH5 startup, shutdown or malfunction. • Failure to report boiler PH5 excess opacity emissions.
12/09/2009	• Failure to calculate HAP emissions generated by the Nardi lumber kilns. • Failure to employ the most current hydrogen chloride emission factor to determine boiler PH5 monthly emissions. • Failure to install boiler PH5 NO_X CERMS based upon stack testing conducted in 2008 and 2009. • Failure to report 12-month rolling VOC emissions for years 2006 through 2009. • Failure to conduct boiler PH5 2009 NO_X source test under representative operating conditions. • Failure to conduct boiler PH5 VOC source test. • Failure to evaluate the filter employed to span boiler PH5 COMS. • Failure to maintain records of boiler PH5 primary circuit data and spark rate. • Failure to calculate boiler PH5 annual capacity factor. • Failure to operate Wellons lumber kilns in a manner consistent with netting analysis that enabled boiler PH5 to avoid PSD review. • Failure to make available fugitive dust control plan.

Inspection Date	Potential Compliance Issues
	• Failure to make a record of fugitive dust surveys.
09/30/2011	• Failure to submit a timely Title V annual compliance certification. • Failure to submit timely Title V deviation reports. • Failure to submit timely Title V annual fee, fee worksheet and emission inventory for 2010. • Failure to conduct a timely PM performance test for boiler PH5. • Failure to conduct periodic VOC emissions testing for boiler PH5. • Failure to track boiler PH5 ESP primary voltage and sparking rate. • Failure to maintain a log documenting boiler PH5 ESP inspections and corrective actions. • Failure to measure hog fuel feed rate to boiler PH5.

3. Emission Inventory

3.1 Emission Inventory Basics

An emission inventory generally reflects either the "actual" or "potential" emissions from a source. Actual emissions generally represent a specific period of time and are based on actual operation and controls. Potential emissions, referred to as potential to emit (PTE), generally represent the maximum capacity of a source to emit a pollutant under its physical and operational design, taking into consideration regulatory restrictions, but only required control devices. PTE is often used to determine applicability to several EPA programs, including Title V, PSD and Section 112 (MACT).

Emissions can be broken into two categories: point and fugitive. Fugitive emissions are those which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. Examples of fugitive emissions are roads, piles that are not normally enclosed, wind blown dust from open areas, and those activities that are normally performed outside buildings. Point sources of emissions include any emissions that are not fugitive.

The equation below represents the general technique for estimating emissions (in tons per year) from each emission unit at the facility. Emissions are calculated by multiplying an emission factor by an operational parameter. To estimate actual emission, WSFPI will need to track the actual operational rates. Note that emission factors may be improved over time. For those estimation techniques that require substantial site-specific parameter tracking, such as piles and roads, emissions associated with a defined operational rate can be estimated to establish a set ratio that can be used to multiply by the actual operational rate in future years, significantly simplifying the annual inventory effort. All of the techniques and site-specific parameters and assumptions should be reviewed each year before estimating emissions to be sure they remain appropriate.

E = EF x OP x K

Where:

E = pollutant emissions in tons/year

EF = emission factor (see Appendix A to this Statement of Basis)

OP = operational rate (or capacity for PTE)

K = 1 ton/2000 lbs for conversion from pounds per year to tons per year

3.2 Potential to Emit (PTE)

WSFPI completed and submitted EPA Part 71 Operating Permit Form EMISS for all emission units as part of its Title V permit renewal application. Form EMISS lists actual and potential emissions. WSFPI did not submit calculations supporting Form EMISS, but WSFPI does submit to EPA an emissions inventory annually around April 1. EPA reviewed those annual emission inventories, and EPA has documented the facility PTE in Appendix A to this Statement of Basis. In some instances, EPA revised the emission estimates provided by WSFPI to more accurately reflect potential emissions from the facility. A summary of WSFPI's PTE is presented in Table 3-1 below. Note that while fugitive emissions are included in Table 3-1, fugitive emissions are not always used to determine program applicability as explained in more detail in Section 4.1 of this Statement of Basis.

Table 3-1 – WSFPI Potential to Emit (tpy)[1]

Pollutant	Emission Units							
	PH5	KLN-N	KLN-W	CYC	MNFA	MFA	PT	Total
CO	90.7							91
Pb	0							0
NO_X[3]	126							126
PM	57.4	1.9	1.5	115.8	0	52.9	1258.8	1488
PM_{10}	67.1	1.9	1.5	98.4	0	26.7	307.0	503
$PM_{2.5}$	67.1	1.9	1.5	57.9	0	12.9	52.2	194
SO_2	39.6							40
VOC[4]	21.5	109.5	22.0	92.3				245
GHG (CO_2e)[5]	121,253							121,253
Facility-wide Single HAP[6]								9
Facility-wide Total HAP[6]								24

[1] Fugitive emissions are included in this table but may not always be used in applicability determinations (see Section 4.1)

[2] CO = carbon monoxide; Pb = lead; NO_X = oxides of nitrogen; PM = particulate matter; PM_{10} = inhalable coarse particulate; particulate matter with diameter 10 microns or less; $PM_{2.5}$ = fine particulate; particulate matter with diameter 2.5 microns or less; SO_2 = sulfur dioxide; VOC = volatile organic compounds; GHG = greenhouse gases; HAP = hazardous air pollutants [see CAA, Section 112(b)]; plant-wide total HAP = all HAPs totaled; plant-wide single HAP = highest individual HAP

[3] NO_X PTE is limited for PH5 to 126 tpy.

[4] VOC PTE is limited for PH5 and KLN-W to 21.5 and 22.0 tpy, respectively.

[5] GHG emissions are not considered in determining Title V applicability pursuant to June 23, 2014 U.S. Supreme Court decision. See http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf. Calculations of GHG emissions are presented in this document for informational purposes only.

[6] HAP PTE is capped by facility-wide emission limits created in non-Title V permit No. R10NT500401

The PTE estimates for the facility generally assume all units operate 8760 hours per year, and boiler PH5 is no exception. Its potential PM emissions were calculated assuming the boiler's emission rate is equal to

the applicable NSPS Subpart Db emission limit of 0.1 lb/MMBtu. This limit is about four times more stringent than the applicable FARR wood-fired boiler stack PM emission limit of 0.2 gr/dscf (approximately 0.4 lb/MMBtu). The permit requires the facility to vent boiler PH5 exhaust to the multiclone and ESP at all times to achieve compliance with the PM limits. Although PH5 is subject to the FARR combustion source stack SO_2 emission limit of 500 ppm and the less stringent FARR solid fuel sulfur content limit of 2% by weight, PH5's PTE was determined assuming 0.2% sulfur in the wood and 15% conversion of sulfur to SO_2. EPA selected these values based upon information presented in an article appearing in a technical journal.[1] According to the article, wood residue contains less than $1/10^{th}$ the FARR sulfur content limit and most of the sulfur is combined with oxygen and the ash products of combustion to form sulfates. At the request of WSFPI, boiler PH5 potential NO_X and VOC emissions are limited to 126 and 21.5 tons per year, respectively, so as to make PSD review unnecessary for the construction of PH5. Although boiler PH5 HAP PTE was largely estimated by employing AP-42 emission factors, individual and total HAP emissions have been limited facility-wide to less than major source thresholds at the request of WSFPI so as to avoid MACT standards that apply to major sources. Boiler PH5 potential greenhouse gas emissions were estimated employing emission factors appearing in the Mandatory Greenhouse Gas Reporting Rule (40 CFR § 98) pursuant to March 2011 EPA guidance document entitled, "PSD and Title V Permitting Guidance for Greenhouse Gases." Page I-1. For an explanation of nearly all emission factors employed to create PH5's PTE inventory, see EPA Region 10's May 8, 2014 memorandums entitled, "Non-HAP Potential to Emit Emission Factors for Biomass Boilers in Pacific Northwest Indian Country" and "HAP Potential to Emit Emission Factors for Biomass Boilers Located in Pacific Northwest Indian Country."

Emission factors for boiler PH5 are based on heat input (fuel) to the boiler. The permit requires WSFPI to track steam production so as to calculate boiler heat input (firing rate) and determine actual emissions. The conversion factor applied to convert steam production to heat input must be based on the latest site specific boiler testing/sampling data. See EPA Region 10's May 8, 2014 memorandum entitled, "Procedure to Determine a Biomass Boiler's Fuel-Heat-Input-To-Steam-Output Ratio." Because WSFPI is required to conduct testing to determine emission unit-specific emission factors for NO_X and VOC in units of "lb/mlb steam," it is not necessary to perform the conversion when calculating actual emissions for those two pollutants.

Like boiler PH5, Wellons kilns potential VOC emissions are limited to 22.0 tons per year so as to make PSD review unnecessary for the construction of PH5. The Wellons kilns were constructed within boiler PH5's 5-year contemporaneous baseline period, and it was necessary to limit the Wellons kilns' VOC emissions so that the project's net emissions increase could be less than the 40 tpy PSD significance threshold. The Nardi kilns' VOC PTE was estimated by employing worst-case emission factors for drying lumber at less than or equal to 200°F derived from lab-scale testing conducted largely by Professor Mike Milota at Oregon State University.[2] Unspeciated VOC (as carbon) emission factors derived from Prof. Milota's work were converted to VOC (as propane) consistent with EPA's Interim VOC Measurement Protocol for the Wood Products Industry - July 2007 (WPP1 VOC).

Although the Nardi kilns and Wellons kilns are each subject to the applicable FARR process source stack PM emission limit of 0.1 gr/dscf, EPA did not consider the limit in determined the kilns' PM PTE because WSFPI did not provide each kiln's physical capacity to vent to the atmosphere. Neither did EPA

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[1] H. S. Oglesby & R. O. Blosser (1980) Information on the Sulfur Content of Bark and its Contribution to SO_2 Emissions when Burned as a Fuel, Journal of the Air Pollution Control Association, 30:7, 769-772, DOI:10.1080/00022470.1980.10465107.

[2] In its September 25, 2014 comments on the draft permit, WSFPI requested EPA to limit the temperature inside the kilns to less than or equal to 200°F so that PTE calculations would reflect emissions resulting from drying at those relatively lower temperatures.

consider the applicable FARR visible emissions limit of 20% opacity because EPA could not quantify a correlation between opacity and PM emissions for the kiln exhaust vents. To estimate PM PTE, EPA employed an uncontrolled emission factor published by the Oregon Department of Environmental Quality. Although the kilns' HAP PTE was estimated by employing worst-case emission factors for drying lumber at less than or equal to 200°F derived from lab-scale testing conducted largely by Professor Mike Milota at Oregon State University, individual and total HAP emissions have been limited facility-wide to less than major source threshold levels at the request of WSFPI.

EPA relied largely upon AP-42, ODEQ guidance, an Oregon State University draft technical report, 1977 and 1978 EPA technical documents along with engineering judgment to estimate PM, PM_{10} and $PM_{2.5}$ potential emissions resulting from traditional sawmill activities like log debarking, sawing, chipping, hogging, mechanical and pneumatic conveyance of wood residuals, wind erosion of wood residual piles, loading wood residuals and truck traffic on paved and unpaved surfaces. EPA did not consider the FARR visible emissions limit of 20% opacity that applies to all these activities because EPA could not quantify a correlation between opacity and PM emissions. Neither did EPA consider the FARR rule for limiting fugitive PM emissions largely because the permit we are issuing does not contain sufficient testing, monitoring, recordkeeping and reporting to support the use of controlled emission factors. EPA relied upon NCASI (National Council for Air and Stream Improvement, Inc.) September 1996 Technical Bulletin No. 723 entitled, "Laboratory and Limited Fuel Measurements of VOC Emissions from Wood Residuals," to provide VOC (as carbon) emission factors for green wood residue by-product recovery cyclones. EPA relied upon NCASI January 1999 Technical Bulletin No. 768 entitled, "Volatile Organic Compound Emissions from Wood Products Manufacturing Facilities, Part I – Plywood," to provide VOC (as carbon) emission factors for dry wood residue by-product recovery cyclones. Emission factors were then converted to VOC (as propane) before employing to estimate potential emissions.

WSFPI is expected to use the emission factors and calculation methods presented in Appendix A unless WSFPI demonstrates that a more appropriate emission factor or calculation method should be used (e.g., results of more recent source testing or sampling, revised emission factors published in AP-42, etc.). It is important to emphasize that to the extent WSFPI relies on any type of emission control technique to estimate emissions used to determine annual fees, or the applicability of a regulatory program, use of the technique must be fully documented and verifiable.

4. Regulatory Analysis and Permit Content

EPA is required by 40 CFR Part 71 to include in this Title V permit all emission limitations and standards that apply to the facility, including operational, monitoring, testing, recordkeeping and reporting requirements necessary to assure compliance. This section explains which air quality regulations apply to this facility and how those requirements are addressed in the permit.

Located within Indian Country, the WSFPI sawmill is subject to federal air quality regulations, but is not subject to state air quality regulations. EPA does not consider any permits issued by Oregon to the WSFPI facility to be applicable requirements. The facility could be subject to tribal air quality regulations; however, the Tribes has not gone through the process of obtaining authorization to be treated in the same manner as states under 40 CFR §§ 49.6 and 49.7 (Tribal Authority Rule) and obtaining approval of air quality regulations as a "Tribal Implementation Plan." Therefore, Tribal air quality regulations, if any, are not federally enforceable and do not meet the definition of "applicable requirement" under 40 CFR Part 71. As such, there are no Tribal air quality regulations in the WSFPI Title V permit.

EPA relied on information provided in WSFPI's Title V permit application and on supplementary information provided by WSFPI to determine the requirements that are applicable to the sawmill. Future modifications to the mill could result in additional requirements.

4.1 Federal Air Quality Requirements

Title V Operating Permit Program. Title V of the CAA and the implementing regulation found in 40 CFR part 71 require major sources (as well as a selection of non-major sources) of air pollution to obtain operating permits and form the legal bases for this permit. A source is major if it has the potential to emit 100 tons per year or more of any air pollutant subject to regulation, 25 tons per year or more of hazardous air pollutants (totaled) or 10 tons per year or more of any single hazardous air pollutant (see 40 CFR 71.2). WSFPI's sawmill is a major source subject to Title V because it has the potential to emit more than 100 tons per year of NO_X, PM_{10}, $PM_{2.5}$ and VOC not counting fugitive emissions (see Table 1 and Appendix A). While PM potential emissions also exceed 100 tons per year, EPA does not consider PM a regulated pollutant for Title V applicability purposes. Although CO_2e potential emissions exceed an EPA-derived 100,000 tons per year major source threshold, the U.S. Supreme Court ruled in a June 23, 2014 decision that GHG emissions cannot be considered in determining Title V applicability.

The Title V operating permit serves as a comprehensive compilation of the air quality requirements that are applicable to a source. The permit also must assure compliance, so source-specific testing, monitoring, recordkeeping and reporting have been added where EPA believes it is necessary, as explained in Section 4.3 (Permit Conditions) of this Statement of Basis below.

Compliance Assurance Monitoring (CAM). CAM applies at time of initial Title V permit issuance for emission units that (a) are subject to an emission limit, (b) employ a control device to comply with the limit, and (c) have post-control PTE equal to or greater than the major source threshold defined in Title V (generally, 100 tons per year). See 40 CFR Part 64. Boiler PH5 (a) is subject to more than one PM emission limit (as discussed below), (b) employs both a multiclone and ESP to comply with the limits, but (c) does not have post-control PTE equal to or greater than 100 tpy.[3] Boiler PH5, however, does have pre-control PTE equal to or greater than 100 tpy.[4] CAM applies at the time of Title V permit renewal for emission units like boiler PH5 that satisfy criteria (a) and (b) above and that have pre-control PTE equal to or greater than the major source threshold defined in Title V. Boiler PH5 must be in compliance with CAM at permit renewal and may also be required to submit a CAM plan if a significant change is made to the unit prior to renewal. The multiclone and ESP that control particulate matter emissions from the boiler are the only control devices at the sawmill.

Prevention of Significant Deterioration (PSD). Under the PSD pre-construction permitting program found in Part C of the CAA and 40 CFR 52.21, no "major stationary source" or "major modification" to a major stationary source can begin actual construction without first obtaining a PSD permit. The PSD program has been changed over the years, but in general, a major stationary source for purposes of the PSD program is a source with a PTE of more than 250 tons per year of any PSD pollutant. Based upon our knowledge of the facility and understanding of its potential emissions, it is not currently a PSD major source. A modification to an existing major source is major if it results in emission increases greater than defined significance levels. Historical reviews of potential PSD projects are difficult due to the lack of specific details about the sources, their emissions and the various applicability requirements in previous PSD programs.

The construction of boiler PH5 would have triggered PSD review but for WSFPI's decision to "net out" of review. The facility's net emission increase resulting from the project was determined to be less than PSD significance thresholds through EPA's issuance of a May 4, 2005 Tile V permit. The permit required

[3] Boiler PH5 Post-Control PTE Calculations. 57.4 tpy PM = (131 MMBtu/hr) X (0.1 lb PM/MMBtu) X (8760 hr/yr) X (ton/2000 lb), where 131 MMBtu/hr equals heat input capacity of boiler PH5 and 0.1 lb PM/MMBtu equals applicable NSPS Subpart Db PM emission limit.

[4] Boiler PH5 Pre-Control PTE Calculations. 321 tpy PM = (131 MMBtu/hr) X (0.56 lb PM/MMBtu) X (8760 hr/yr) X (ton/2000 lb), where 131 MMBtu/hr equals heat input capacity of boiler PH5 and 0.56 lb PM/MMBtu equals AP-42 uncontrolled emission factor.

WSFPI to do the following: (a) retire boilers PH1, PH2 and PH4, (b) limit boiler PH5 actual NO_X and VOC emissions to less than 126 and 10 tons per year, respectively, and (c) limit Wellons kilns actual VOC emissions to less than 29 tons per year. The VOC emission limits for boiler PH5 and the Wellons kilns were later amended to 21.5 and 22.0 tons per year, respectively, through EPA's issuance of an October 10, 2008 Title V permit amendment. Even with the higher amended limits, the net emissions increase remains just below the VOC significance threshold as illustrated in Table 4-1 below. The amended VOC emission limits from 2008 are being incorporated into the Title V permit renewal so that construction of boiler PH5 can continue to "net out" of PSD review.

Table 4-1 – VOC Netting Analysis for Boiler PH5 Construction

Pollutant	Boiler PH5	Wellons Kilns	Steam Demand	Retired Boilers	Net Change	SER	PSD?
VOC	21.5	22.0	5.0	(9.5)	39.0	40	No

The October 10, 2008 Title V permit amendment also incorporated new emission limits from a non-Title V permit enabling WSFPI to construct another boiler without undergoing PSD review. That additional boiler was never constructed, and WSFPI requested EPA to terminate the underlying synthetic minor permit. EPA terminated non-Title V permit R10NT500300 on September 30, 2013.

As stated previously in Section 2.5 of this Statement of Basis, WSFPI has recently undertaken ARRA-funded activities related to boiler PH5 improvements. There are no records in EPA files indicating that any applicability determination was made by EPA. EPA has not drawn any conclusions regarding compliance with permitting requirements for this project, and no enforcement shield is implied or granted.

New Source Performance Standards (NSPS). Four NSPS subparts may apply to boiler PH5 (a steam generating unit): 40 CFR 60, Subparts D (Fossil-Fuel-Fired Steam Generators), Da (Electric Utility Steam Generating Units), Db (Industrial-Commercial-Institutional Steam Generating Units) and Dc (Small Industrial-Commercial-Institutional Steam Generating Units). Subparts D and Da do not apply because boiler PH5 heat input capacity is 131 mmBtu/hr, about one-half the applicability threshold of 250 mmBtu/hr. Subpart Dc does not apply because boiler PH5's heat input capacity is outside Subpart Dc's applicability range of 10 to 100 mmBtu/hr. NSPS Subpart Db applies to boiler PH5 because (a) the boiler was constructed after June 19, 1984 and (b) its heat input capacity is greater than 100 MMBtu/hr but less than 250 MMBtu/hr.

Determining which NSPS Subpart Db PM emission standard applies depends upon whether the boiler commenced construction, reconstruction or modification on or before February 28, 2005. A PM emission limit of 0.1 lb/MMBtu applies if construction commenced on or before February 28, 2005. If construction commenced after February 28, 2005, then a PM emission limit of 0.030 lb/MMBtu applies. Construction appears to have commenced before February 28, 2005 based upon January 16, 2004 Steam Supply Agreement entered into by chief executive officers of Wellons and WSFPI. The more stringent emission limit also applies if WSFPI reconstructed the boiler. EPA has no information indicating that boiler PH5 has been reconstructed, and WSFPI indicates that the fixed capital cost of the recently installed new components associated with ARRA-funded improvements did not exceed 50 percent of the fixed capital cost that would have been required to construct a comparable entirely new boiler. Subpart A of 40 CFR Part 60 applies because NSPS Subpart Db applies.

National Emission Standards for Hazardous Air Pollutants (NESHAP). With a few exceptions, MACT standards promulgated under 40 CFR Part 63 apply to "major sources" of HAP. Section 112(a)(1) and 40 CFR 63.2 define a "major source" as a stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls in the aggregate, 10 tons per year or more of any HAP or 25 tons per year or more of any combination of HAP. Because WSFPI and WSCP are both owned and operated by the Tribes and because they are located on contiguous properties, the HAP emissions of WSFPI and WSCP must be added together to

determine if emissions exceed 25 tons per year for all HAP combined or 10 tons per year for any single HAP. There are at least three MACT standards that might be applicable to the Warm Springs operations if major for HAP: Subparts DDDDD (Industrial, Commercial and Institutional Boilers and Process Heaters at Major Sources), DDDD (Plywood and Composite Wood Products Manufacture – includes lumber kilns), and SSSSS (Refractory Products Manufacturing). The first two would apply to the WSFPI operation and the latter would apply to the WSCP operation. The compliance dates for the three MACT standards are January 31, 2016, October 1, 2007 and April 17, 2006, respectively.

Based on information provided by the Tribes, EPA estimates that potential HAP emissions from WSCP are around 0.04 ton per year, whereas potential HAP emissions (in the absence of enforceable PTE limits) from the existing WSFPI operation are approximately 53 tons per year. See emissions inventory in Appendix A. WSFPI's potential HAP emissions have been limited to less than major source thresholds beginning May 4, 2005 with EPA's issuance of a Title V permit containing synthetic minor limits on HAP emissions. Then on September 24, 2007, EPA issued a separate non-Title V permit limiting HAP emissions to less than major source thresholds. Requirements from that non-Title V permit are being revised and concurrently incorporated into this Title V permit renewal. With enforceable limits on HAP emissions from WSFPI in place, WSFPI and WSCP are collectively considered a minor (aka area) HAP source, thereby avoiding major source MACT standards that might otherwise apply. If it is later discovered that the revised non-Title V permit, and by extension the Title V permit, did not actually limit facility-wide HAP emissions to less than major source thresholds, EPA will not enforce against WSFPI for failing to comply with major source MACT requirements during the time period WSFPI complied with the supposed "HAP synthetic minor" permit terms. In other words, EPA is "shielding" WSFPI from harm in the event EPA erred in the crafting of the supposed "HAP synthetic minor" permit terms. EPA will explain the error to WSFPI and present options for remedying the situation going forward.

EPA has recently finalized a MACT standard that applies to boilers at area HAP sources. The regulation is codified at 40 CFR 63, Subpart JJJJJJ - Industrial, Commercial, and Institutional Boilers for Area Sources, and boiler PH5 at WSFPI is an affected source (biomass boiler). WSFPI is required to conduct an energy assessment and tune the boiler before March 21, 2014. Thereafter, WSFPI is required to tune the boiler every five years. Tune-up would be required every two years except for the fact that WSFPI employs an oxygen trim system to control combustion in the boiler.

Section 111(d) and Section 129 Regulations. There are no CAA, Section 111(d) or 129 regulations that apply to the type of emission units at WSFPI. Biomass combustion in the boilers is not considered solid waste or municipal waste combustion or incineration.

Federal Air Rules for Reservations (FARR). On April 8, 2005, EPA promulgated a Federal Implementation Plan (FIP) for Reservations in Idaho, Oregon and Washington. This FIP is commonly referred to as the Federal Air Rules for Reservations (FARR). EPA published the FARR rules that generally apply to Indian Reservations in EPA Region 10 in 40 CFR 49.121 to 49.139. The FARR rules that specifically apply on the 1855 Warm Springs Reservation are codified at 40 CFR 49.11071 to 49.11080. Those FARR requirements that apply to the permittee and have been included in the permit are discussed in Section 4.3 of this document. Several requirements of the FARR that are in effect on the Warm Springs Reservation do not apply to WSFPI's mill. Table 4-2 below lists the FARR requirements that do not apply to the permittee and explains why.

Table 4-2 – Inapplicable FARR Requirements

Citation	Description	Reason Inapplicable
49.125(d)(1)	Limits particulate matter emissions from combustors except wood-fired boilers	Only wood-fired boiler exists at WSFPI

Citation	Description	Reason Inapplicable
49.127	Rules that apply to wood waste burners (wigwam burners)	No wigwam burners exist at WSFPI
49.128	Rules that apply to wood veneer, plywood, particleboard and hardboard manufacturing	WSFPI does not produce any of the products listed
49.129(d)(2)	Limits SO_2 from process source stacks	None of WSFPI's processes emit SO_2
49.130(d)(1-6) and (8)	Limits amount of sulfur in liquid fuels, coal and gaseous fuels	WSFPI only burns wood waste and automotive diesel is exempt
49.130(e)(1-2) and (4)	Specifies reference methods for determining sulfur content of liquid fuels, coal and gaseous fuels	WSFPI only burns wood waste and automotive diesel is exempt
49.130(f)(1)(i-ii)	Additional requirements that apply to liquid and gaseous fuels	WSFPI only burns wood waste and automotive diesel is exempt
49.135	Restricts emissions determined to be detrimental to human health or welfare	Actual requirements will result from EPA's determination and subsequent permits or orders that address an issue

WSFPI listed "burning" rules (40 CFR 49.131, 132, 133 and 134) as not applying because the facility indicates that it does not engage in open burning, agricultural burning, or forestry and silvicultural burning. Of those rules, the permit-related "burning" regulations (40 CFR 49.132, 133 and 134) are not listed in Table 4-2 above because the rules are not included in the Warm Springs FIP. In other words, they are not in effect on the Warm Springs Reservation. The general rule for open burning at 40 CFR 49.131 is in effect on the Warm Springs Reservation, and industrial facilities are not exempt from the rule's open burning restrictions.

Acid Rain Program. Title IV of the CAA created a SO_2 and NO_X reduction program found in 40 CFR Part 72. The program applies to any facility that includes one or more "affected units" that produce power. WSFPI's boiler is not a "unit" as defined in 40 CFR 72.2 because it does not combust fossil fuels.

Mandatory Greenhouse Gas Reporting Rule. This rule requires sources above certain emission thresholds to calculate, monitor, and report greenhouse gas emissions. According to the definition of "applicable requirement" in 40 CFR 71.2, neither 40 CFR part 98, nor CAA §307(d)(1)(V), the CAA authority under which 40 CFR part 98 was promulgated, are listed as applicable requirements for the purpose of Title V permitting. Although the rule is not an applicable requirement under 40 CFR part 71, the source is not relieved from the requirement to comply with the rule separately from compliance with their part 71 operating permit. It is the responsibility of each source to determine applicability to part 98 and to comply, if necessary.

4.2 Other Federal Requirements

EPA Trust Responsibility. As part of the EPA Region 10's direct federal implementation and oversight responsibilities, EPA Region 10 has a trust responsibility to each of the 271 federally recognized Indian tribes within the Pacific Northwest and Alaska. The trust responsibility stems from various legal authorities including the U.S. Constitution, Treaties, statutes, executive orders, historical relations with Indian tribes, and in this case the Treaty with the Middle Oregon Tribes, November 15, 1865. In general terms, EPA is charged with considering the interest of tribes in planning and decision making processes. Each office within EPA is mandated to establish procedures for regular and meaningful consultation and collaboration with Indian tribal governments in the development of EPA decisions that have tribal

implications. EPA Region 10's Office of Air, Waste and Toxics has contacted the Tribes to invite consultation on the WSFPI Title V operating permit renewal application.

Endangered Species Act (ESA). Under this act, EPA is obligated to consider the impact that a federal project may have on listed species or critical habitats. It is EPA's conclusion that the issuance of this Title V permit will not affect a listed specie or critical habitat because it does not authorize new emissions units, increase existing emission limits or impose any new work practice requirements. Therefore, no additional analysis and no additional requirements will be added to this permit for ESA reasons. EPA's no-effect determination concludes EPA's obligations under Section 7 of the ESA. For more information about EPA's obligations, see the Endangered Species Consultation Handbook: Procedures for Conducting Consultation and Conference Activities under Section 7 of the Endangered Species Act, published by the FWS and NMFS (March 1998, Figure 1).

National Environmental Policy Act (NEPA). Under Section 793(c) of the Energy Supply and Environmental Coordination Act of 1974, no action taken under the CAA shall be deemed a major Federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act of 1969. This permit is an action taken under regulations implementing the CAA and is therefore exempt from NEPA.

National Historic Preservation Act (NHPA). As noted earlier, the issuance of this Title V permit does not authorize new emissions units, increase existing emission limits or impose any new work practice requirements. No changes to the facility are expected as a result of this permit action. Consequently, no adverse effects are expected, and further review under NHPA is not indicated.

Environmental Justice (EJ) Policy - Under Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations,* signed on February 11, 1994, EPA is directed, to the greatest extent practicable and permitted by law, to make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations in the United States. This permit action does not allow new or additional emissions and therefore impacts. As a result, there is no information available that indicates that there are disproportionately high and adverse impacts to a minority or low-income population.

4.3 Permit Conditions

This Title V operating permit compiles all of the applicable requirements that apply to the permittee. Additional monitoring, recordkeeping and reporting requirements have been created where needed so the permit assures compliance with all of the applicable requirements. In general, each permit condition in the permit is explained below. Certain permit conditions are self-explanatory, and thus are not further discussed. The permit is organized into the following nine sections:

Permit Section 1:	Source Information and Emission Units
Permit Section 2:	Standard Terms and Conditions
Permit Section 3:	General Requirements
Permit Section 4:	Facility-Specific Requirements
Permit Section 5:	Unit-Specific Requirements – PH5 (Hog Fuel-Fired Boiler)
Permit Section 6:	Unit-Specific Requirements – KLN-N (Nardi Lumber Kilns)
Permit Section 7:	Unit-Specific Requirements – KLN-W (Wellons Lumber Kilns)
Permit Section 8:	Unit-Specific Requirements – CYC (Wood Residue Cyclones)
Permit Section 9:	Unit-Specific Requirements – MNFA (Miscellaneous Non-Fugitive Activities)

4.3.1 Permit Section 1 – Source Information and Emission Units

This permit section contains a brief description of the facility and a list of emission units. A more detailed description of the facility can be found in Section 2 of this Statement of Basis.

4.3.2 Permit Section 2 – Standard Terms and Conditions

This permit section includes generic compliance terms that are required in all Title V permits, but are not subject to the annual compliance certification requirements found in Permit Condition 3.49.

Permit Condition 2.1 explains that the language in the underlying regulations takes precedence over paraphrased language in the permit. Some applicable requirements are paraphrased in the permit with the intention of clarifying the requirement, but with no intention of changing the underlying meaning of the requirement. Where there is a difference between the language in a permit and an underlying regulation, the wording in the underlying regulation should be used to interpret and implement the requirement. This permit condition also notes some underlying authorities that may have been used to create additional requirements in this permit.

Permit Conditions 2.4 and 2.5 address a general permit shield which states that compliance with the permit is deemed compliance with the applicable requirements listed in the permit. The permittee is responsible for complying with any applicable requirements that exist but have not been included in the permit. The permittee did not request a specific permit shield for any specific requirement excluded from this permit and none is being granted other than for major source MACT requirements as discussed in Section 4.1 in this Statement of Basis.

Permit Conditions 2.12 through 2.14 address the expiration of the permit and the ramifications if the permittee does or does not renew their permit. It is important to note that, if the permittee does not submit a complete and timely renewal application, the permittee's right to operate is terminated. The expiration date of the permit is listed on the top right-hand corner of the front page of the permit. Specific requirements regarding permit renewal are in Permit Conditions 3.51 and 3.52.

Permit Conditions 2.15 through 2.17 address options for making certain physical and operational changes in the facility that do not require a permit modification. If the permittee uses any of these options, they must comply with the applicable recordkeeping requirement found in Permit Condition 3.32 and reporting requirements found in Permit Conditions 3.38 and 3.39.

4.3.3 Permit Section 3 – General Requirements

This permit section includes conditions that are required in all Title V permits. In some cases, facility-specific testing, monitoring, recordkeeping and reporting requirements for these permit conditions might be found in Section 4 of the permit because those requirements can vary from permit to permit. Unless otherwise specified, emission units are subject to the general requirements in Section 3 of the permit as well as the facility-specific and unit-specific requirements in Sections 4 through 9.

Permit Conditions 3.1 and 3.2 are general compliance schedule requirements. Because EPA is not aware of any non-compliance at the time of permit issuance, there is no issue-specific compliance schedule in Section 4 of the permit.

Permit Condition 3.3 requires the permittee to allow EPA-authorized representatives access to the facility and required records.

Permit Conditions 3.4 through 3.8 restrict open burning wherever the FARR applies including at industrial facilities. If the permittee performs any open burning, recordkeeping requirements specific to open burning found in Permit Condition 3.33 will apply.

Permit Condition 3.9 through 3.11 limit visible emissions, require the use of either Reference Method 9 or a continuous opacity monitoring system (COMS) for determining compliance with the limit, and provide exception to the rule. Reference Method 9 includes specific guidance for reading opacity when there is a wet plume (both attached and detached and directs the observer to take readings excluding the portion of the plume that includes uncombined water (droplets). In the vast majority of cases, the likelihood of exceeding the 20% opacity limit due to the presence of uncombined water is very low because an experienced observer would know that he/she should not read that portion of the plume. However, there are meteorological conditions that can prevent uncombined water (droplets) from completely evaporating in a plume (e.g., 100% relative humidity and a saturated plume). The provision in Permit Condition 3.11 addresses that situation.

Because the facility does use (and is required to use pursuant to NSPS Subpart Db) a COMS to monitor visible emissions generated by boiler PH5, the exception in Condition 3.11.2 does apply to boiler PH5. Although the FARR and NSPS Subpart Db visible emissions limits are numerically identical, their exceptions are not. Whereas the FARR limit applies at all times except during start-up, soot blowing or grate cleaning, the NSPS Subpart Db limit applies at all times except during start-up, shutdown or malfunction. Unlike NSPS Subpart Db, the FARR exception is limited in duration and frequency to 15 consecutive minutes in any consecutive eight-hour period. And lastly, the FARR limits visible emissions (to less than 60% opacity) during these exceptions while NSPS Subpart Db does not.

Because testing, monitoring, recordkeeping and reporting for assuring compliance with the visible emission limit can change based on the emission unit in question, the testing, monitoring, recordkeeping and reporting requirements are contained in facility-specific requirements in Section 4 of the permit, or in each emission unit-specific section, as appropriate. The general monitoring, recordkeeping and reporting for this requirement is the periodic visible emissions survey (plant walkthrough) specified in Permit Conditions 4.4 through 4.11. These general requirements, however, do not apply to boiler PH5 as noted in Condition 4.11 given the use of a COMS.

Permit Conditions 3.12 through 3.17 restrict fugitive particulate matter emissions and require a plan be created to assure the use of reasonable precautions to prevent fugitive emissions. The plan is based on a survey of the facility and is updated annually. This annual survey can be accomplished simultaneously with the periodic visible emission survey requirement in Permit Conditions 4.4 through 4.11, as long as both requirements are fully complied with.

Permit Condition 3.18 addresses requirements in the Chemical Accident Prevention Program found in 40 CFR Part 68. This program requires sources that use or store regulated substances above a certain threshold to develop plans to prevent accidental releases. Based on information in their application, there are no regulated substances above the threshold quantities in this rule at this facility; therefore, the facility is not currently subject to the requirement to develop and submit a risk management plan. However, this requirement is included in the permit as an applicable requirement because the permittee has an ongoing responsibility to submit a risk management plan if a substance is listed that the facility has in quantities over the threshold amount, or if the facility ever increases the amount of any regulated substance above the threshold quantity. Including this term in the permit minimizes the need to reopen the permit if the facility becomes subject to the requirement to submit a risk management plan.

Permit Conditions 3.19 and 3.20 address the Stratospheric Ozone and Climate Protection Program found in 40 CFR Part 82. This program requires sources that handle regulated materials to meet certain procedural and certification requirements. There may be equipment at the facility that uses or contains chlorofluorocarbons (CFCs) or other materials regulated under this program. All air conditioning and refrigeration units must be maintained by certified individuals if they contain regulated materials.

Permit Condition 3.21 addresses asbestos demolition or renovation activity found in 40 CFR Part 61, Subpart M (NESHAP). This program requires sources that handle asbestos-containing materials to follow

specific procedures. If the permittee conducts any demolition or renovation activity at their facility, they must assure that the project is in compliance with the federal rules governing asbestos, including the requirement to conduct an inspection for the presence of asbestos. This requirement is in the permit to address any demolition or renovation activity that may occur at the facility.

Permit Conditions 3.22 through 3.30 specify the procedures that must be followed whenever the permit requires emissions testing or sampling in an emission unit-specific section of the permit. If there is a conflict between these permit conditions and an emission unit-specific permit condition, the specific permit condition should be followed. Concentration-based emission limits required to be corrected to a specific oxygen concentration in the flue gas often do not contain a protocol to convert measured concentrations to specified oxygen levels. Permit Condition 3.28 provides a protocol for such a conversion.

Permit Condition 3.30 requires the facility to submit an emission test report to EPA within 60 days of completing the emission test. The previous Part 71 permit provided the facility only 45 days (after completing test) to submit the report. In a July 31, 2014 Title V permit renewal issued to Empire Lumber Company (ELC) for its facility on the Nez Perce Reservation, EPA provided ELC a 60-day test report deadline. EPA is extending the same deadline to the WSFPI for the sake of maintaining uniformity among Part 71 sources.

Permit Condition 3.31 describes general recordkeeping that has been added to the permit using Part 71 authority to assure that there is good documentation for any monitoring that the permittee performs.

Permit Condition 3.32 describes recordkeeping requirements that apply only if the permittee makes off-permit changes. Certain off-permit changes are allowed in Permit Condition 2.15.

Permit Condition 3.33 describe recordkeeping requirements that apply if the permittee performs open burning. The open burning recordkeeping was added using Part 71 authority. Open burning is restricted in Permit Conditions 3.4 through 3.8.

Permit Condition 3.34 includes recordkeeping that applies to fee records including the duration that the records must be maintained. The duration is consistent with that required by Title V (see Permit Condition 3.35).

Permit Condition 3.35 sets the duration that records must be maintained. Both Title V and FARR records must be maintained for five years. These two requirements have been combined (streamlined) into one permit condition. If there is ever a conflict between these requirements and a more restrictive emission unit-specific permit condition, the specific permit condition should be followed.

Permit Conditions 3.36 and 3.37 require the permittee to submit or correct submitted information when requested by EPA and as needed. The permittee has an ongoing obligation to assure that all data in its Title V application is correct and to notify EPA of any errors or omissions.

Permit Condition 3.38 and 3.39 describe reporting requirements that apply only if the permittee makes off-permit changes (Permit Condition 3.38) or section 502(b)(10) changes (Permit Condition 3.39). Certain off-permit changes are allowed in Permit Condition 2.15. Section 502(b)(10) changes are allowed in Permit Conditions 2.16.

Permit Condition 3.40 includes the address for submittals to EPA Region 10. All reports and notices, except for fee payments (see Permit Condition 3.43), should be sent to this address. Copies of each document sent to EPA should be sent to the Tribe.

Permit Conditions 3.41 through 3.45 require submittal of an annual emission inventory (of actual emissions) and payment of fees for Part 71 purposes. These requirements refer to Permit Condition 4.1 for the actual due date by which fees and emissions must be submitted each year. The per-ton fee rate varies each year; the permittee should contact EPA to obtain the current rate. The submittal of the emission

inventory is timed to coincide with the payment of fees because annual Title V fees are based on actual emissions generated during the previous calendar year. Appendix A to this statement of basis documents the methods, techniques, and assumptions that EPA believes provide the most accurate basis for estimating actual emissions for this facility. As explained in Section 3.2 of this statement of basis, the emission estimation techniques listed in this statement of basis should be used to calculate the annual emissions inventory, unless the permittee has other information showing why another technique more accurately represents emissions. Also note that the actual emission estimates differ from the facility's PTE because actual emission are calculated based on actual operations, not maximum operational capacity.

Note that the FARR emission inventory required in Permit Condition 3.46 to be reported at the same time can be combined with the Part 71 emission inventory as long as it is clear which emissions inventory is for which purpose, because the pollutant lists for each emission inventory are slightly different.

At this time, greenhouse gases (GHG) are neither regulated air pollutants nor regulated air pollutant (for fee calculation) as those terms are defined at 40 CFR § 71.2. The permittee is not required to pay Title V fees on its GHG emissions.

Permit Condition 3.46 requires submittal of an annual emission inventory (of actual emissions) for FARR registration purposes. Appendix A to this statement of basis documents the methods, techniques, and assumptions that EPA believes provide the most accurate basis for estimating actual emissions for this facility. As explained in Section 3.2 of this statement of basis, the emission estimation techniques listed in this statement of basis should be used to calculate the annual emissions inventory, unless the permittee has other information showing why another technique more accurately represents emissions. Also note that the actual emission estimates differ from the facility's PTE because actual emission are calculated based on actual operations, not maximum operational capacity.

Note that the FARR emission inventory is required to be submitted at the same time as the Part 71 fees and emission inventory required in Permit Conditions 3.41 through 3.45. The Part 71 and FARR emission inventories can be combined as long as it is clear which emissions inventory is for which purpose, because the pollutant lists for each emission inventory are slightly different.

Permit Conditions 3.47 and 3.48 require semi-annual monitoring reports and prompt deviation reports. Determinations of deviations, continuous or intermittent compliance status, or violations of the permit are not limited to the testing or monitoring methods required by the underlying regulations or this permit. Failure to meet any permit term or permit condition, including emission standards, is considered a deviation. Other credible evidence (including any evidence admissible under the federal rules of evidence) must be considered by the source and EPA in such determinations. The timing for reporting deviations, as well as other data collected, depends on the circumstances, as explained in these permit conditions. The deadline for the semiannual monitoring report was changed from the 30th day to the 60th day following the end of the reporting period in the permit renewal in an effort by EPA to make all of the Title V permits consistent. In a July 31, 2014 Title V permit renewal issued to ELC for its facility on the Nez Perce Reservation, EPA provided ELC a 60-day monitoring report deadline.

Permit Condition 3.49 requires an annual compliance certification. The permittee must certify compliance with the permit conditions in sections 3 through 9. The permittee does not need to annually certify compliance with the provisions in permit sections 1 or 2. Consistent with Permit Condition 2.6, however, if a permittee is aware of any information that indicates noncompliance, that information must be included in the annual compliance certification. In a year when the permit is renewed or revised, the permittee must address each permit for the time that permit was in effect. The deadline for the annual compliance certification has changed from January 30 to February 28 in the permit renewal in an effort by EPA to make all of the Title V permits consistent. In a July 31, 2014 Title V permit renewal issued to ELC for its facility on the Nez Perce Reservation, EPA provided ELC until February 28 to submit annual

compliance certification. Forms for the annual compliance certifications may be obtained on the internet at http://www.epa.gov/air/oaqps/permits/p71forms.html.

Permit Condition 3.50 requires the permittee to certify the truth, accuracy and completeness of all documents (notices, reports, data, and etc) submitted to EPA. The certification must be signed by a responsible official as defined in 40 CFR § 71.2. The facility's responsible officials are listed on the first page of the permit. The permittee should request an administrative amendment of the permit if the responsible official for the facility changes.

Permit Conditions 3.51 and 3.52 require the permittee to submit an application for renewal and describe some of the information that must be included in the application. As explained in Permit Conditions 2.12 through 2.14, failure to submit a complete application on time terminates the permittee's right to operate. The expiration date of the permit is listed on the top right-hand corner of the front page of the permit.

4.3.4 Permit Section 4 – Facility-Specific Requirements

This permit section includes applicable requirements and related testing, monitoring, recordkeeping and reporting that apply either to multiple emission units or on a facility-specific basis. Unless otherwise specified, emission units are subject to the facility-specific requirements in Section 4 of the permit as well as the general and unit-specific requirements in Sections 3 and 5 through 9 of the permit.

Permit Conditions 4.1 lists the due date for the annual fees and emission reports required in Permit Conditions 3.41 through 3.46. Note that the due date continues to be April 1.

Permit Conditions 4.2 and 4.3 limit the sulfur content of the solid fuel burned in any combustion device, specify the method for determining compliance and specify the monitoring and recordkeeping. The facility burns only wood residue in the boiler. The underlying rule allows the permittee to simply keep records showing that only wood residue is burned because naturally occurring sulfur content of wood waste is normally much less than the limit of 2% by weight.

Permit Conditions 4.4 through 4.11 require a quarterly survey (also called a plant walkthrough) for visible and fugitive emissions as well as specific follow-up steps (investigation, corrective action, RM9 observation and additional recordkeeping and reporting) if visible or fugitive emissions are observed. If observed visible or fugitive emissions can not be eliminated within 24 hours, a tiered sequence of RM9 opacity determinations must be performed beginning with an initial 30-minute period of readings every 15 seconds. The frequency (e.g. daily or weekly) for conducting follow-up RM9 opacity readings is based upon whether any 6-minute average opacity exceeds 20%. Observations of visible or fugitive emissions during a survey are not considered deviations; however, any resulting RM9 6-minute average opacity determination above 20% is considered a permit deviation pursuant to Permit Conditions 3.47 and 3.48. The annual fugitive particulate matter survey required in Permit Condition 3.13 can be accomplished simultaneously with a quarterly survey required in this permit condition as long as both requirements are fully complied with.

This permit condition serves as the periodic monitoring for several fugitive and particulate matter limits found in the permit. This requirement applies to emission sources that normally do not exhibit visible or fugitive emissions. If the permittee prefers a specific periodic monitoring approach for any emission sources subject to this requirement, the permittee can propose a new approach as a permit modification.

Permit Conditions 4.12 and 4.13 limit HAP emissions and provide emission-unit-specific procedures for calculating emissions monthly to determine compliance with the 12-month rolling limits. For KLN-N and KLN-W, the permit specifies that the recorded monthly specie-specific and temperature-specific dry lumber production rates be multiplied by the corresponding specie-specific and temperature-specific emission factors appearing in Appendix A of the permit to determine HAP emissions. Although

temperature in the kilns shall not exceed 200°F pursuant to Permit Conditions 6.2 and 7.3, emission factors for both low (≤ 200 °F) and high-temperature (>200°F) drying appear in Appendix A. The selection of an emission factor to determine actual emissions is based upon the actual temperature measured, not the temperature allowed.

For PH5, the permit specifies that the recorded monthly heat input value be (a) multiplied by 0.0220 lb/MMBtu to determine total HAP, and (b) multiplied by individual emission factors appearing in Appendix B of the permit to determine individual HAP. The 0.0220 lb/MMBtu emission factor for total HAP is the summation of all factors appearing in Appendix B except for the dibenzofurans, naphthalene and 2,3,7,8-tetrachlorodibenzo-p-dioxin factors. Because each of these three HAP are also accounted for in the calculation of the HAP polycyclic organic matter "POM", their individual contributions for this calculation are discounted so as to avoid double-counting.

As discussed in Section 4.1 of this Statement of Basis, WSFPI and WSCP are together considered one source for determining major source MACT applicability. Because WSCP's unrestricted potential total HAP emissions are estimated to be 0.04 tpy, limiting WSFPI's potential HAP emissions to less than 9 (individual HAP) and 24 tpy (total HAP) is sufficient to establish that their combined activities do not constitute a major HAP source. The limits, often called synthetic minor limits, were first created in the 2007 non-Title V permit issued to WSFPI and are being revised concurrent with this Title V permitting action. The limits apply only to WSFPI activities. WSFPI will be treated as an area source for NESHAP/MACT reasons as long as they comply with the limits.

Permit Conditions 4.14 and 4.15 require permittee to determine and record PH5's "FHISOR" (MMBtu/mlb) using the methodology specified in the most recent version of EPA Region 10's "Procedure to Determine a Biomass Boiler's Fuel-Heat-Input-To-Steam-Output Ratio." In addition to the requirement to determine FHISOR within 120 days of permit issuance, FHSIOR shall also be determined hereafter each time the company otherwise conducts EPA Reference Method 2 testing for any reason. The testing is to be carried out while PH5 is operating at or near the maximum rate observed during the twelve months preceding the test.

Permit Conditions 4.16 through 4.21 require permittee to calculate and record the monthly and rolling 12-month HAP emissions generated by biomass boiler and lumber drying. This section contains requirements to track certain aspects of HAP-emitting activities so that the emission factors appearing in Appendices A and B of the permit can be employed to calculate actual emissions. Records of emission calculations and parameters used to calculate emissions shall be maintained for at least five years.

In addition to tracking steam mass flow rate, steam pressure and temperature are also required to be tracked so as to create a record which can be weighed to judge the representativeness of FHISOR in day-to-day operations. This record can be reviewed to determine the conditions under which to conduct testing to determine FHISOR in the future.

Permit Conditions 4.19 and 4.20 require WSFPI to track the volume of lumber in each kiln charge along with the maximum dry bulb temperature observed during the drying cycle. With this information, WSFPI can calculate the HAP and VOC emissions generated while drying a load of lumber. It is necessary to track the dry bulb temperature of the air entering the stack (i.e. load or car) of lumber because lab-scale testing performed by Oregon State University's Professor Mike Milota (and relied upon by EPA for deriving species-specific emission factors) illustrates that emissions of VOC and HAP's methanol and formaldehyde are dependent upon drying temperature; specifically the drying temperature of air entering the stack. There are two sets of emission factors for VOC, total HAP, methanol and formaldehyde for each species of wood; one set for maximum dry bulb temperatures less than or equal to 200ºF and the other for maximum dry bulb temperatures greater than 200 ºF.

Permit Condition 4.22 requires the facility to annually submit to EPA a record of the twelve monthly 12-month emissions calculations. For ease in coordinating submittals, this report is required to be submitted concurrently with the annual FARR registration submittal. As specified in 40 CFR § 49.138(f), the annual FARR registration submittal must be submitted with the annual emission report and fee calculation required by 40 CFR Part 71. This annual report must include details on how the emissions were calculated as well as identifying the sources for various data elements.

Permit Conditions 4.23 through 4.26. EPA has placed area source boiler MACT (NESHAP Subpart JJJJJJ) requirements in the section of the permit reserved for facility-specific requirements, and not emission unit-specific requirements. This is because the area source boiler MACT requirements extend beyond just the boiler. They extend, for instance, to energy use systems like steam turbine generators and lumber drying kilns.

The facility combusts in their boiler only material satisfying the definition of biomass as that term is defined at 40 CFR § 63.11237. Biomass means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue and wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (*e.g.,* almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste as that term is defined at 40 CFR § 241.2. Because the boiler combusts only biomass, it is in the NESHAP Subpart JJJJJJ biomass subcategory of boilers pursuant to 40 CFR § 63.11200(b). It is with this in mind that EPA Region 10 created permit terms reflecting NESHAP Subpart JJJJJJ requirements.

Permit Condition 4.23. Existing biomass boilers are subject to periodic tune-up management practices for PM (surrogate for urban metal HAP) and CO (surrogate for urban organic HAP) based upon finding that periodic tune-ups represent generally available control technology (GACT), (78 FR 7489, February 1, 2013). An oxygen trim system, according to 40 CFR § 63.11237, means a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or carbon monoxide monitor that automatically provides a feedback signal to the combustion air controller. Whereas boilers not employing an oxygen trim system are required to undergo a tune-up once every two years, the tune-up frequency is relaxed to once every five years for boilers employing said system. The facility indicates that its boiler employs an oxygen trim system. The NESHAP Subpart JJJJJJ tune-up requirements at 40 CFR § 63.11223(b)(1) and (2) related to inspection of burner and flame pattern do not apply to the facility's boiler because the boiler does not employ any burners. Burners are typically employed to combust gas and liquid fuels along with pulverized coal. In contrast, the facility employs a fuel chute to introduce biomass into their boiler.

Permit Conditions 4.24 and 4.25. Existing biomass boilers are subject to a beyond-the-floor control technology or GACT requirement to conduct an energy assessment, (76 FR 15573, March 21, 2011). For boilers like the one at this facility with an annual heat input capacity greater than 1.0 trillion Btu but less than 2.0 trillion Btu, the duration of the energy assessment will be up to 24 on-site technical labor hours pursuant to the definition of energy assessment at 40 CFR § 63.11237.[5] This length of time may be extended at the discretion of the source. EPA has not established a minimum value for the amount of time necessary to conduct on-site technical labor.

The requirement to evaluate systems to identify energy savings opportunities extends to the boiler system and any energy use system (under the control of the source) that accounts for at least 20 percent of the boiler's energy (e.g., steam, hot water, or electricity). See definition of energy assessment at 40 CFR §

[5] Boiler PH5 annual heat input capacity of 1.15 TBtu = (131 MMBtu/hr) X (8,760 hr/yr) X (1 TBtu/1x10^6 MMBtu)

63.11237. The energy use systems serving as the basis for the percent of affected boiler energy production may be segmented by production area or energy use area as most logical and applicable to the source. The term boiler system, as defined in 40 CFR § 63.11237 means the boiler and associated components, such as feedwater systems, combustion air systems, fuel systems, blowdown systems, combustion control systems, steam systems, and condensate return systems, directly connected to and serving the energy use systems. Similarly, the term energy use system includes any of the following systems located at the CAA Section 112 stationary source that use energy provided by the boiler: (a) process heating; compressed air systems; machine drive (motor, pumps, fans); process cooling; facility heating, ventilation, and air conditioning systems; hot water systems; building envelop; and lighting; or (b) other systems that use steam, hot water, process heat, or electricity, provided by the boiler. Energy use systems are only those systems using energy clearly produced by the boiler either (a) directly as steam or process heat, or (b) through an associated steam turbine generator in the form of electricity.

The steam produced by this facility's boiler is delivered to one of three main systems at the CAA Section 112 source: (1) WSFPI lumber drying kilns, (2) WSFPI steam turbine generators or (3) WSCP. The WSFPI steam turbine generators, in turn, provide electricity to WSFPI power equipment. The equipment and operation of all kilns are either identical or substantially similar. An energy assessment of one kiln would be carried out in much the same way as the energy assessment for another. Conducting an energy assessment of all kilns is limited in scope, an effort that is neither disjointed nor unwieldy as cautioned against by EPA in responding to comments for the national rulemaking in December 2012.

Although WSCP and WSFPI are not considered one source in the context of PSD and Title V permitting programs given that the two have different two-digit SIC codes, the two are considered one source in the context of the NESHAP program. Under CAA Section 112, activities are considering one source if (a) "common control" is exerted over the activities and (b) the activities are located on contiguous or adjacent properties. Both of these tests are satisfied as the Warm Springs Tribal Council exerts control over both WSCP and WSFPI, and the two businesses are located on contiguous property.

A source operating under an energy management program compatible with ISO 50001 is not required to conduct an energy assessment. An energy management program, as defined at 40 CFR § 63.11237, means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, and energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

Permit Condition 4.26. The following sentence appears in Condition 4.26, "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." Because the boiler is not subject to an emission limitation, there is no "level" for emissions to be reduced by. Achieving compliance with general duty to minimize emissions goes beyond complying with tune-up and energy assessment requirements of Conditions 4.23 through 4.25. Compliance with this requirement will be determined, in part, based upon inspection of records created and maintained by the permittee to comply with 40 CFR §§ 63.10(b)(2)(iii), 63.11223(b)(6) and 63.11225(c)(4) and (5).

Permit Conditions 4.27 through 4.30. The permittee is required to conduct monitoring and maintain records to document compliance with GACT work practice standards and emission reduction measures. The permittee is also required to document that when it combusts biomass that is considered a non-

hazardous secondary material as that term is defined at 40 CFR § 241.2, that it is combusting a fuel and not a solid waste.[6]

Permit Condition 4.27. The requirement to measure and record boiler exhaust stack CO concentration is satisfied if measurements are taken before and after the performance tune-up. It is not necessary to take measurements between interim tasks in the tune-up process.

Permit Condition 4.28. Should WSFPI choose to operate in accordance with an energy management program so as to comply with Condition 4.24.2, Condition 4.28 requires WSFPI to, among other things; maintain records that document WSFPI's energy management program and how it is compatible with ISO 50001.

Permit Condition 4.30. The following background about the different biomass streams combusted in the boiler provides some context for Condition 4.30. A majority of the biomass combusted in the boiler is clean hogged bark. This bark is generated on-site by the de-barking of logs prior to further processing into lumber. This clean cellulosic biomass is considered a traditional fuel as those terms are defined at 40 CFR § 241.2. The facility also combusts biomass that is generated off-site and received at the facility via truck delivery. Whether this off-site material is considered clean cellulosic material or non-hazardous secondary material is determined on a load-by-load basis. The facility occasionally combusts in the boiler bark that has been recovered from the unpaved log yard floor and processed back into a fuel. This material is considered a non-hazardous secondary material. After drying the material by exposing it to sunlight and air, dirt and rocks that are caked on the bark is dislodged through the use of air knives and screens. A portion of the off-site biomass received at the facility may also be processed in a similar fashion prior to becoming a fuel.

Permit Conditions 4.30.1 and 4.30.2. These permit conditions refer to legitimacy criteria that must be satisfied in order to consider non-hazardous secondary material to be a fuel.

Permit Condition 4.30.3. This permit condition refers to a petition process whereby the Regional Administrator may grant a non-waste determination that a non-hazardous secondary material that is used as a fuel, which is not managed within the control of the generator, is not discarded and is not a solid waste when combusted pursuant to 40 CFR § 241.3(c).

Permit Condition 4.30.4. WSFPI does not combust any of the materials that EPA has listed as non-waste under 40 CFR § 241.4(a).

Permit Condition 4.31. The underlying NESHAP Subpart JJJJJJ requirement at 40 CFR § 63.11223(b)(6) requires the permittee to track certain tune-up related information and to submit it to the EPA if requested by the Administrator. EPA is taking this opportunity to require the permittee to submit certain tune-up related information as part of the semi-annual monitoring reports required by Condition 3.47.

The requirement in 40 CFR § 63.11223(b)(6)(iii) to track the type and amount of fuel used over the twelve months prior to the tune-up would have appeared as an element of Permit Condition 4.26, but the requirement does not apply to the boiler because it combusts only biomass. It is not physically capable of using any other type of fuel listed at 40 CFR § 63.11200.

Permit Condition 4.32. The permittee is required to submit its NESHAP Subpart JJJJJJ Notification of Compliance Status (NOCS) to EPA electronically through CDX pursuant to 40 CFR § 63.11225(a)(4).

[6] When EPA refers to secondary materials in this context, EPA means any material that is not the primary product of a manufacturing or commercial process, and can include post-consumer material, off-specification commercial chemical products or manufacturing chemical intermediates, post-industrial material, and scrap. A non-hazardous secondary material is a secondary material that, when discarded, would not be identified as a hazardous waste under 40 CFR § 261.

EPA is not providing the permittee the opportunity to submit the NOCS through some other mechanism given that the CEDRI NESHAP Subpart JJJJJJ-specific reporting form is now available.

Permit Condition 4.33. EPA is utilizing its streamlining authority under 40 CFR § 71.6(a)(3)(i)(A) and its discretion under 40 CFR § 63.11225(b) to require the permittee to submit a NESHAP Subpart JJJJJJ compliance certification report to EPA each year by February 28 (rather than March 15) for the previous year's operations.

Permit Conditions 4.36 and 4.37. The PSD regulation applicability test for modifications was changed in December 2002. The rule change resulted in a new applicable requirement for PSD major sources. Although EPA does not believe the facility to be a PSD major source based upon our current knowledge of the facility's emissions, our understanding may change as our knowledge of its emissions improves. Therefore, this term is included in the operating permit. In summary, when the permittee considers a plant modification project to be exempt from PSD via the method specified in 40 CFR §§ 52.21(b)(41)(ii)(a) through (c) and there is a reasonable possibility that there will be a significant emissions increase resulting from the project, then the permittee must fulfill specified requirements related to documentation, monitoring, and notification. This term will be relevant to the facility only when the permittee is contemplating making physical or operational changes to the facility. In those instances it is strongly recommended that the permittee contact EPA to discuss their plans and verify their assumptions.

4.3.5 Permit Section 5 – Unit-Specific Requirements – PH5 (Hog Fuel-Fired Boiler)

Permit Condition 5.1 restricts WSFPI to combusting only wood in the boiler. WSFPI has requested EPA to put this restriction in place so that it becomes unnecessary to track fuel usage as would otherwise be required pursuant to 40 CFR § 60.49b(d).

Pursuant to 40 CFR § 60.49b(d), the owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for each fuel. The purpose of determining the annual capacity factor for each fuel is to determine what sections of NSPS Subpart Db apply to your source.

The annual capacity factor, as defined in 40 CFR § 60.41b, is, "The ratio between the actual heat input to a steam generating unit from "(each fuel)", during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity" (emphasis added). The annual capacity factor of wood is needed to determine which particulate matter limit you will be subject to, under 40 CFR § 60.43b(c) of the Standard for PM NSPS Subpart Db. Based on this definition, the annual capacity factor could be anywhere from zero to one for wood.

Under NSPS Subpart Db, there is an option for a less stringent limit if certain conditions are met, among them, the requirement to have an annual capacity factor of less than 30 percent for wood. If the annual capacity factor is greater than 30 percent for wood a more stringent emission limit for PM of 0.10 lb/million Btu applies.

With the fuel restriction in place along with associated recordkeeping requirement specified in Condition 4.3, EPA can be assured that the annual capacity factors for all other fuels aside from wood will be zero. Therefore, there is no need to calculate the annual capacity factors for all fuels aside from wood. With WSFPI subject to the more stringent limit for PM of 0.10 lb/million Btu, there is also no need for WSFPI to calculate the annual capacity factor for wood. The requirement to record the amount of wood combusted each day is not needed for the purposes of calculating the annual capacity factor, as required by 40 CFR § 60.49b(d).

EPA Region 10 previously made a similar determination in response to a June 16, 2005 request from Bennett Forest Industries. EPA's October 4, 2005 response letter can be accessed on the internet at http://cfpub.epa.gov/adi/pdf/adi-nsps-0700014.pdf.

Permit Condition 5.2 limits the sulfur dioxide (SO_2) emissions from the boiler to 500 ppmdv at 7% O_2 and describes the emission testing methods for determining compliance. As the boiler only uses wood waste as fuel, SO_2 emissions are expected to be well below the emission limit. For an example, see the calculation below.

$$SO_2 \text{ concentration} = \frac{(\text{fuel S}) \times (SO_2 \text{ conversion}) \times (SO_2 \text{ molar volume}) \times (1\times10^6) \times (1\times10^6)}{(\text{f-factor}) \times (\text{fuel heat content}) \times SO_2 \text{ molar weight})}$$

$$= \frac{0.00134 \times 2 \times 385 \times 1\times10^6 \times 1\times10^6}{13556 \times 8590 \times 64}$$

$$= 138 \text{ ppmdv at } 7\% O_2$$

where:

expected fuel S =	0.134% by weight, dry basis, from article entitled, "Information on the Sulfur Content of Bark and its Contribution to SO_2 Emissions when Burned as a Fuel." Journal of the Air Pollution Control Association, 30:7, 769-772.
SO_2 conversion =	2 lb SO_2/lb S
SO_2 molar volume =	385 dscf/lbm
f-factor =	9037 x (21%) / (21%-7%) = 13556 dscf/MMBtu at 7% O_2, from 40 CFR 60, Appendix A, Method 19, Table 19-2. 9037 dscf/MMBtu value is from April 2010 boiler PH5 stack test and corresponding hog fuel analysis
fuel heat content =	8590 Btu/lb, dry basis, from April 2010 boiler PH5 hog fuel analysis.
SO_2 molar weight =	64 lb SO_2/lbm
Btu conversion =	1×10^6 Btu per MMBtu
ppm conversion factor =	1×10^6 parts per million parts

Using the worst-case sulfur content of bark from technical journal article, the concentration will be around 138 ppm, well under the limit of 500 ppm. Using the AP-42 emission factor for SO_2 emissions (0.025 lb/MMBtu = 0.01 %) results in even lower stack emissions (11 ppm). The AP-42 emission factor reflects the fact that most of the sulfur in the bark is converted to sulfate and is either entrained in the ash released from either the boiler grate, entrained in the ash released from the multiclone hoppers, or is discharged to the atmosphere as fly ash (PM). To document compliance with the fuel sulfur limit in Permit Condition 4.2, the permittee must document that only wood waste fuel is used (see Permit Condition 4.3). The monitoring in Permit Condition 4.3 will adequately assure compliance with Condition 5.2 as well.

Permit Condition 5.3 limits the particulate matter (PM) emissions from the boiler to 0.2 gr/dscf at 7% O_2 and describes the emission testing method for determining compliance. Requirements to operate and maintain the boiler control device can be found in Permit Condition 5.6. Periodic testing of the boiler to confirm compliance can be found in Permit Condition 5.11. Monitoring to assure compliance with the limit can be found in Permit Conditions 5.17 and 5.18.

Permit Condition 5.4. Because construction of boiler PH5 commenced before February 28, 2005 with a contractual obligation between Wellons and WSFPI for fabrication, erection and installation of the boiler, a PM emission limit of 0.1 lb/MMBtu applies. The parties entered into such an agreement on January 16, 2004.

Permit Condition 5.5 limits boiler PH5 visible emissions to 20% opacity. The exhaust gas opacity limit is the same regardless of whether construction of the boiler commenced before or after February 28, 2005.

Permit Condition 5.6.1 requires the boiler exhaust to be vented to the multiclone and ESP at all times. While there is no testing to confirm it, it can be assumed that both control devices are needed for the boiler to comply with the NSPS Subpart Db particulate matter limit. It is likely that the boiler could achieve compliance with the FARR particulate matter emission limit and the FARR and NSPS Subpart Db opacity limits with just the multiclone. This requirement ensures the emission control devices are used and will be considered when estimating PTE for the boiler.

Permit Condition 5.6.2 requires the boiler control devices to be maintained. Consistent with the requirement to ensure boiler emissions are controlled at all times, this requires ensures the control devices are operating correctly and hopefully that the boiler stays in compliance with the particulate matter and visible emission limits.

Permit Condition 5.9 limits boiler PH5 NO_X emissions to 126 tpy so that the construction and continued operation of boiler PH5 can continue without PSD review as explained in Section 4.1 of the Statement of Basis above. Upon permit issuance, the facility is required to determine compliance by employing a NO_X emission factor of 0.421 lb/mlb steam; a factor that was derived based upon May 2009 Reference Methods 2 and 7E emissions testing as follows:

$$\frac{0.0421 \text{ lb } NO_X}{\text{mlb steam}} = C \times \frac{1.194 \times 10^{-7} \text{ lb/scf}}{\text{ppmv}} \times Q \times \frac{60 \text{ min}}{\text{hr}} / S$$

where:

C equals 3-run average NO_X concentration of 127.67 ppm dry measured during Reference Method 7E testing May 27, 2009.

1.194×10^{-7} lb/scf per ppmv NO_X is relationship for expressing NO_X concentration based upon ideal gas law at EPA standard conditions. See value in Table 19-1 of Reference Method 19 in Appendix A to 40 CFR Part 60.

Q equals 3-run average 34496 dscf/min exhaust flow rate measured during Reference Method 2 testing May 27, 2009.

S equals 3-run average 75.156 mlb/hr steam production rate measured during Reference Method 2 and 7E testing May 27, 2009.

Since May 2009, boiler PH5 has undergone a physical change through an ARRA-funded project. EPA is not certain the May 2009 emission factor is still representative. WSFPI is required to conduct emissions testing to derive an updated NO_X emission factor so that when it calculates its emissions, WSFPI is employing an emission factor that is representative. The closer the calculated emissions are to the 126 tpy limit, the more important it is for the emission factor to be representative. So, the frequency of testing to determine an updated emission factor increases as calculated emissions increase.

Should actual emissions (as calculated through the use of an emission factor) begin to approach the 126 tpy threshold, the appropriateness of an emission-factor approach to calculating emissions comes into question. EPA does not know the extent to which a single emission factor derived for a single load condition and measured over a 3-hour period is representative of load conditions (some similar, some not) experienced several months, or even years later. So, should actual emissions (as calculated through the use of an emission factor) exceed 113 tpy (about 90% of the 126 tpy limit), WSFPI is required to employ a NO_X continuous emission rate monitoring system (CERMS) to calculate emissions. Employing a CERMS will provide an additional level of precision and accuracy, thus providing assurance that calculated and reported emissions represent what is actually being emitted.

Permit Condition 5.10 limits boiler PH5 VOC emissions to 21.5 tpy so that the construction and continued operation of boiler PH5 can continue without PSD review as explained in Section 4.1 of the Statement of Basis above. Upon permit issuance, the facility is required to determine compliance by employing a VOC emission factor of 0.054 lb/mlb steam; a factor that was derived based upon April 2006 Reference Methods 2 and 25 emissions testing and VOC species-specific exhaust gas profile from Table 1.6-3 of AP-42, September 2003 as follows:

$$\frac{0.054 \text{ lb VOC}_{\text{as compound emitted}}}{\text{mlb steam}} = 1.355 \text{ X } C \text{ X } \frac{3.118\text{x}10^{-8} \text{ lb/scf}}{\text{ppmv}} \text{ X } Q \text{ X } \frac{60 \text{ min}}{\text{Hr}} / S$$

where:

1.355 equals factor to convert $VOC_{\text{as carbon}}$ to $VOC_{\text{as compound emitted}}$ and is expressed as $[(MW_{\text{wt-avg VOC}}) / (MW_C)] \text{ X } [(\#C_C) / (\#C_{\text{wt-avg VOC}})]$. Employing VOC species-specific exhaust gas profile from Table 1.6-3 of AP-42, September 2003 results in the following calculation: (64.689/12.0110) X (1/3.975) = 1.355. This same 1.355 $VOC_{\text{as carbon}}$ to $VOC_{\text{as compound emitted}}$ conversion factor is also employed in calculating PH5 VOC PTE as presented in Appendix A to this Statement of Basis.

C equals 3-run average $VOC_{\text{as carbon}}$ concentration of 61.4 ppm dry measured during Reference Method 25 testing April 6 and 7, 2006.

$3.118\text{x}10^{-8}$ lb/scf per ppmv $VOC_{\text{as carbon}}$ is relationship for expressing carbon concentration based upon ideal gas law at EPA standard conditions and is calculated as follows:

$$\frac{\text{mass}_{\text{pollutant}}}{\text{volume}_{\text{air}}} = \frac{\text{volume}_{\text{pollutant}}}{\text{volume}_{\text{air}}} \text{ X } \frac{(P_{std}) \text{ X } (MW_{carbon})}{[21.83(\text{inHg})(\text{ft}^3)(\text{lb-mol})^{-1}(^{\circ}\text{R})^{-1}] \text{ X } T_{std}}$$

$$\frac{\text{mass}_{\text{pollutant}}}{\text{volume}_{\text{air}}} = [\text{ppmv}] \text{ X } 1\text{x}10^{-6} \text{ X } \frac{(29.92 \text{ inHg}) \text{ X } (12.011 \text{ lb/lb-mol})}{[21.83(\text{inHg})(\text{ft}^3)(\text{lb-mol})^{-1}(^{\circ}\text{R})^{-1}] \text{ X } (528^{\circ}\text{R})}$$

$$\frac{\text{mass}_{\text{pollutant}}}{\text{volume}_{\text{air}}} = [\text{ppmv}] \text{ X } 3.118\text{x}10^{-8} \text{ lb/scf}$$

where $21.83(\text{inHg})(\text{ft}^3)(\text{lb-mol})^{-1}(^{\circ}\text{R})^{-1}$ is universal gas constant and PV = (m/M)RT

Q equals 3-run average 25967 dscf/min exhaust flow rate measured during Reference Method 2 testing April 6 and 7, 2006.

S equals 3-run average 75.467 mlb/hr steam production rate measured during Reference Method 2 and 25 testing April 6 and 7, 2006. (76 + 75.1 + 75.3 = 75.467)

The 0.054 lb VOC/mlb steam emission factor derived above is a 35 percent increase over a 0.040 lb VOC/mlb steam emission factor that would have been derived given the 2005 Title V permit based upon the same testing but without considering the 1.355 conversion factor. The 2005 Title V permit did not specify any methodology for converting Method 25 results that are express VOC as carbon. The 2008 Title V modification, however, did specify that Method 25 results were to be converted to express VOC as propane. That would have resulted in a $VOC_{\text{as propane}}$ emission factor of 0.049 lb VOC/mlb steam as you multiply EPA Method 25's $VOC_{\text{as carbon}}$ result by a ratio of 44/36 where 44 equals molecular weight of propane (C_3H_8) and 36 equals the molecular weight of 3 carbon atoms. The 0.054 lb VOC/mlb steam emission factor required by today's permit is a 10 percent increase over the 0.049 lb VOC/mlb steam emission factor that would have been derived given the 2008 Title V permit modification.

Since April 2006, boiler PH5 has undergone a physical change through an ARRA-funded project. EPA is not certain the April 2006 emission factor is still representative. WSFPI is required to conduct emissions testing to derive an updated VOC emission factor so that when it calculates its emissions, WSFPI is

employing an emission factor that is representative. The closer the calculated emissions are to the 21.5 tpy limit, the more important it is for the emission factor to be representative. So, the frequency of testing to determine an updated emission factor increases as calculated emissions increase.

EPA considered, but is not proposing, requiring WSFPI to employ a VOC CERMS should calculated VOC emissions climb to within 10% of the 21.5 tpy limit. EPA considered how often other sources are required to employ VOC CERMS, the benefit of a VOC CERMS over more frequent testing, and the likelihood that boiler PH5's actual VOC emissions would exceed the 21.5 tpy limit before its NO_X emissions exceed the 126 tpy limit. Although EPA has developed a performance specification for VOC CEMS (Performance Specification 8 to Appendix B of 40 CFR Part 60), it is rare for a permitting authority to require a source to employ a Method 25A analyzer outside of an emission test. Just as in Reference Method 25A testing (carbon counter), the VOC CERMS calculates actual VOC emissions by estimating the VOC constituents in the exhaust. With the emission factors in effect upon issuance of this permit (0.421 lb/mlb steam for NO_X and 0.054 lb/mlb steam for VOC), WSFPI will exceed the 126 tpy NO_X limit before exceeding the 21.5 tpy VOC limit. This is the case despite the VOC factor likely overestimating emissions.[7] Boiler PH5's annual VOC emissions will be approaching 75% of its annual allowance as its NO_X emissions exceed the NO_X PSD avoidance threshold.[8] For these reasons, EPA is not proposing at this time to require WSFPI to employ a VOC CERMS to determine compliance with 21.5 tpy PSD avoidance limit.

Permit Condition 5.11 requires emission one-time testing of particulate matter (PM) and visible emissions 6 to 9 months prior to expiration of the permit. EPA considered the results of previous testing before determining when testing should next be conducted. Initial performance testing conducted within 6 months of startup in April 2006 (0.002 lb/MMBtu, 0% opacity) and subsequent performance testing in April 2010 (0.0053 lb/MMBtu, 0% opacity) illustrate how well the multiclone and ESP are capable of performing to reduce emissions well below the NSPS Subpart Db 0.1 lb/MMBtu PM and 20% opacity limits. During the tests, WSFPI operated the boiler at or near maximum load (80,000 lb/hr steam). Whereas today, WSFPI normally operates the boiler around 25% of maximum load (20,000 lb/hr steam). Judging from the margin of compliance demonstrated in April 2006 and again in April 2010, it is likely that the multiclone and ESP are capable of comfortably achieving compliance with the PM and visible emissions limits under a 20,000 lb/hr steam load condition.

Because WSFPI is required to employ a COMS to continuously monitor visible emissions, it is unnecessary to require the facility to conduct periodic Reference Method 9 observations.

During the one PM and visible emissions test that is being required, boiler, multiclone and ESP operation and certain fuel characteristics (determined through fuel sampling and analysis) must be documented.

Permit Condition 5.12. Because the permittee prefers to measure and track steam output rather than fuel input, during each emission test (PM, NO_X or VOC) a ratio of heat input to steam output must be determined using procedures in EPA May 8, 2014 memorandum entitled, "Procedure to Determine a Biomass Boiler's Fuel-Heat-Input-To-Steam-Output Ratio. The ratio is then used to convert measured steam flows (mlb/hr) to heat input (MMBtu/hr) which can be applied to emission factors that are normally in terms of heat input (lb/MMBtu). The notable exceptions are NO_X and VOC; in which case test-derived emission factors are in units "lb/mlb steam."

Permit Condition 5.13 requires the permittee to conduct testing within 120 days of permit issuance to determine a new NO_X emission factor. This new emission factor will replace the May 2009 emission factor that is being employed to calculate NO_X emissions upon permit issuance. WSFPI indicates that

[7] October 27, 2006 EPA Region memorandum entitled, " Review of the Compliance Test Report for Warm Springs Forest Products Industries – Warm Springs, Oregon"

[8] 16 tpy VOC = (0.054 lb VOC/mlb steam) X (126 tpy NO_X/0.421 lb NO_X/mlb steam)

boiler PH5 may be shut-down between November 2013 and January 2014 due to shortage of logs. If the boiler is shut-down (due to seasonal shortage of logs) at any time within the first 120 days after permit issuance, then testing must be conducted within 120 days of boiler re-start.

Permit Condition 5.14 requires the permittee to conduct additional testing in the future to generate a new NO_X emission factor. The frequency of testing, if any, depends upon how close actual 12-month rolling NO_X emissions are to the 126 tpy PSD avoidance limit. If annual NO_X emissions reach or exceed 113 tpy, then the requirement to conduct periodic testing is replaced with the requirement to employ a CERMS to determine NO_X emissions.

Permit Condition 5.15 requires the permittee to conduct testing within 120 days of permit issuance to determine a new VOC emission factor. This new emission factor will replace the April 2006 emission factor that is being employed to calculate VOC emissions upon permit issuance. EPA is carrying forward into this Title V permit renewal the VOC testing enhancements introduced in the October 2008 significant modification to the Title V permit. WSFPI indicates that boiler PH5 may be shut-down between November and January due to shortage of logs. If the boiler is shut-down (due to seasonal shortage of logs) at any time within the first 120 days after permit issuance, then testing must be conducted within 120 days of boiler re-start.

In addition, EPA is requiring that the EPA Reference Method 25 test results (reported as $VOC_{\text{as carbon}}$) be converted to $VOC_{\text{as compound emitted}}$ by multiplying by a factor of "1.355." The conversion factor is derived in Appendix A to this Statement of Basis. See VOC PTE calculations for PH5 in Appendix A.

The 1.355 conversion factor was employed to calculate the April 2006 test-derived "0.054 lb $VOC_{\text{as compound emitted}}$/mlb steam" emission factor appearing in Permit Condition 5.10.1 as illustrated earlier.

Permit Condition 5.16 requires the permittee to conduct additional testing in the future to generate a new VOC emission factor. The frequency of testing, if any, depends upon how close actual 12-month rolling VOC emissions are to the 21.5 tpy PSD avoidance limit.

CAM - Permit Condition 5.17 requires WSFP to install and operate a COMS that complies with 40 CFR Part 60 Subpart A and Appendix B. NSPS requires the COMS performance to be checked prior to PM and opacity performance tests. Under the authority of CAM and Part 71 enhanced monitoring, the permit adds additional performance checks every quarter. The COMS is used to "indicate" exceedences of the FARR and NSPS Subpart Db opacity limits. Similarly, the COMS is used to "indicate" excursions of FARR and NSPS Db PM limits through implementation of CAM. Because an excursion is defined as a maximum 1-hour average opacity value of 6 percent (less than one-half the applicable FARR and NSPS Subpart Db visible emissions limits), the quarterly calibration error check shall be performed using attenuators as described in ASTM D 6216-98, section 7.5 for applicable standards of 10 to 19 percent opacity.

EPA Reference Method 9 readings are used to "determine" compliance with the opacity limits unless WSFPI requests that the COMS be the compliance determination method. EPA Reference Method 5 is used to "determine" compliance with the PM limits. WSFPI has the option to use opacity data from a certified monitor or to perform an EPA Reference Method 9 test when fulfilling opacity performance testing requirements. If selected, the COMS would then become the compliance determination method in place of RM 9.

CAM - Permit Condition 5.18. Permit condition requires ongoing monitoring of boiler operations, multiclone and ESP. Each of the parameters are required to be monitored (measured with a gauge indicator) continuously; however, the frequency of data recording varies. Because WSFPI will base actual emissions on steam production, the permit requires continuous recording of the pounds of steam produced with one-hour average block average being recorded. One-hour block average steam pressure and temperature values, required to be recorded once per hour given that WSFPI already does so, provide

indicators of boiler duty (and potential changes in boiler use) and allow estimation of steam heat content. One-hour block average boiler excess oxygen, required to be recorded once per hour, provides an indication of boiler performance with the concern that much lower oxygen levels may lead to incomplete combustion and much higher oxygen levels could cause the combustion chamber to be too cool. Pressure drop across the multiclone, required to be recorded once per month, is generally related to multiclone performance (pluggage or corrosion); however, but is often only adequate for indicating significant changes in performance. One-hour block average secondary voltage (volts and kilovolts, respectively), secondary current (amps and milliamps, respectively) and sparking rate of each ESP field is required to be recorded once per hour. All three parameters are related to ESP performance. The boiler oxygen, multiclone pressure drop, and ESP secondary power input and sparking rate readings can be useful for trouble-shooting performance problems and for tracking equipment condition trends.

The permit includes a 90% data capture requirement for recordkeeping on an hourly or daily schedule – that is at least 90% percent of the data required to be measured and recorded each hour or day must be measured and recorded to comply with the permit. Data capture of less than 90% for steam production, boiler excess oxygen and ESP parameters is a permit deviation. This provides relief for the more stringent monitoring/recording schedules during a given month; whereas, steam pressure and multiclone pressure drop must be recorded at least once each month to comply with the data capture requirement.

WSFPI is being provided 60 days after permit issuance to begin monitoring pressure drop across the multiclone because equipment is not already installed to perform such measurement. Because WSFPI is already monitoring and recording values for the other parameters, no grace period is being provided.

Permit Condition 5.19 requires the performance, operational and maintenance criteria from Part 64 that applies to the monitoring equipment required in Permit Condition 5.18. If the ESP is functioning as designed, the boiler can comfortably achieve compliance with NSPS Subpart Db 0.1 lb/MMBtu PM emission limit. This is shown in the 2006 and 2010 performance tests in which emissions were observed to be less than 5% of the limit. During these tests, visible emissions were measured (COMS and RM9) and determined to be around 1 percent opacity. Boiler operating data provided to EPA for review illustrates that visible emissions are less than 3 percent opacity for more than 99 percent of the time.

WSFPI reviewed additional boiler operating data with an eye for looking through the days when there were start up, shut downs, and malfunctions in order to develop a better understanding of how opacity is correlated in times when the ESP is running well, but the loading is too great for the ESP to handle. WSFPI noticed in the data that 6% was a common threshold during these times. Therefore, WSFPI believes that 6% opacity would function well as a threshold for checks of the ESP with the assumption here being that if the ESP malfunctions during normal loading, the result will be similar to when the ESP is functioning but with excess loading. EPA accepts WSFPI's proposal to define a visible emissions excursion as a 1-hour average value greater than 6 percent opacity. An excursion indicates that the ESP may be malfunctioning. At such time, it would be prudent to check the ESP and take corrective action if warranted.

Permit Condition 5.20 specifies what Part 64 requires the permittee to do when an excursion occurs. An excursion does not necessarily mean that the multiclone and ESP are malfunctioning. For instance, a COMS reading of greater than 6% opacity may result from presence of excess water vapor in the exhaust gas generated by the combustion of relatively wet hog fuel. No corrective action would be warranted in that instance. When poor combustion in the boiler generates exhaust gas with excessive PM resulting in visible emissions greater than 6% opacity, the corrective action may be to address boiler operation rather than multiclone and ESP performance. For other excursions, perhaps it is the multiclone or ESP that is not performing as designed. Each excursion warrants its own investigation to determine the root cause.

Permit Condition 5.21 simply states EPA's option to require a quality improvement plan (QIP); this condition becomes a requirement only in the event EPA informs the permittee that a QIP is required.

Permit Condition 5.22 serves as a safeguard against incorrectly set excursion/exceedance thresholds by requiring the redefinition of the thresholds as needed.

Permit Condition 5.23 requires, consistent with Permit Condition 3.35, the maintenance of all records and supporting information.

Permit Condition 5.24. EPA is carrying forward into this Title V permit renewal, with virtually no edification, the NO_X CERMS enhancements introduced in the October 2008 significant modification to the Title V permit.

Permit Condition 5.25 requires the facility to monitor and record, during all emissions testing, values for the parameters required to be monitored for in Permit Conditions 5.17 and 5.18. The recorded information enables the facility and EPA to understand how the boiler, multiclone and ESP were operating during testing. And if the emission unit and control devices are operated differently in the future, a better judgment can be made (with this information in hand) as to the representativeness of the test-derived emission factors or ongoing compliance with the PM limits.

Permit Condition 5.26 requires the facility to determine monthly heat input by tracking steam production and employing a test-derived fuel-heat-input-to-steam-output ratio to enable the calculation of each month's heat input. Initially, the facility is required to employ a fuel-heat-input-to-steam-output ratio of 1.520 MMBtu/mlb steam that is based upon the most recent stack testing and fuel sampling and analysis performed in April 2010.[9]

Permit Condition 5.27 requires the permittee to inspect each year the ESP internals to confirm good condition. The permittee is also required to document each inspection and any follow-up activity resulting from it.

Permit Conditions 5.28 through 5.30 are additional NSPS recordkeeping requirements.

Permit Conditions 5.31 and 5.32 requires additional NSPS reporting related Reference Method 9 testing and the use of a COMS.

Permit Condition 5.33 requires CAM reporting of excursions and exceedances related to compliance with boiler PH5 PM and opacity limits.

Permit Condition 5.34 requires reporting (including deviation and semiannual reporting) of information related to compliance with NO_X PSD avoidance limit. Unlike previous Title V permits to WSFPI, EPA is not requiring permittee to submit semiannual emissions calculations. Instead, reporting of 12-month rolling emissions totals and supporting documentation is required annually by April 1.

Permit Condition 5.35 requires reporting (including deviation and semiannual reporting) of information related to compliance with VOC PSD avoidance limit. Unlike previous Title V permits to WSFPI, EPA is not requiring permittee to submit semiannual emissions calculations. Instead, reporting of 12-month rolling emissions totals and supporting documentation is required annually by April 1.

4.3.6 Permit Section 6 – Unit-Specific Requirements – KLN-N (Nardi Lumber Kilns)

Permit Condition 6.1 limits particulate matter emissions and describes the test method for determining compliance. No unit-specific testing or monitoring is required. The visible and fugitive emission monitoring required in Permit Conditions 4.4 through 4.10 will serve as the periodic monitoring to assure compliance for this unit.

Permit Condition 6.2 limits kiln drying temperature.

[9] 1.520 MMBtu/mlb = (33,212 dscf/min) X (60 min/hr) X ((20.9-9.19)/20.9) X (MMBtu/(9,037 dscf) X (hr/81.3 mlb steam)

4.3.7 Permit Section 7 – Unit-Specific Requirements – KLN-W (Wellons Lumber Kilns)

Permit Condition 7.1 limits particulate matter emissions and describes the test method for determining compliance. No unit-specific testing or monitoring is required. The visible and fugitive emission monitoring required in Permit Conditions 4.4 through 4.10 will serve as the periodic monitoring to assure compliance for this unit.

Permit Condition 7.2 limits the Wellons lumber kilns' VOC emissions to 22.0 tpy so that the construction and continued operation of boiler PH5 can continue without PSD review as explained in Section 4.1 of the Statement of Basis above.

Permit Condition 7.3 limits kiln drying temperature.

4.3.8 Permit Section 8 – Unit-Specific Requirements – CYC (Wood Residue Cyclones)

Permit Condition 8.1 limits particulate matter emissions and describes the test method for determining compliance. No unit-specific testing or monitoring is required. The visible and fugitive emission monitoring required in Permit Conditions 4.4 through 4.10 will serve as the periodic monitoring to assure compliance for this unit.

4.3.9 Permit Section 9 – Unit-Specific Requirements – MNFA (Miscellaneous Non-Fugitive Activities)

Permit Condition 9.1 limits particulate matter emissions and describes the test method for determining compliance. No unit-specific testing or monitoring is required. The visible and fugitive emission monitoring required in Permit Conditions 4.4 through 4.10 will serve as the periodic monitoring to assure compliance for this unit.

5. Public Participation

5.1 Public Notice and Comment

As required in 40 CFR §§ 71.11(a)(5) and 71.8, all draft operating permits must be publicly noticed and made available for public comment. The public notice of permit actions and public comment period is described in 40 CFR § 71.11(d). There is a 30 day public comment period for actions pertaining to a draft permit. For this permit action, the requirements of 40 CFR §§ 71.11(a)(5) and 71.8 have been satisfied as follows:

1. Publishing the public notice for this draft permit in a daily or weekly newspaper of general circulation in the area affected by this source. In this case, publication was provided in the weekly Madras Pioneer newspaper on Wednesday August 27, 2014 and in the biweekly Spilyay Tymoo tribal newspaper on Friday August 29, 2014;
2. Providing a copy of the public notice to: the permit applicant, the affected states, the air pollution control agencies of affected states, the Tribal, city and county executives, any comprehensive land use planning agency, any state or federal land manager whose lands may be affected by emissions from the source, the local emergency planning authorities which have jurisdiction over the area where the source is located and all persons who submitted a written request to be included on EPA Region 10's mailing list for Title V permitting actions;
3. Making available from August 27, 2014 through September 25, 2014 on the Region 10 public notice website [Link from http://yosemite.epa.gov/R10/homepage.nsf/Information/R10PN/]

during the public comment period, a copy of the public notice and the draft permit and statement of basis prepared by EPA;

4. Making available from August 27, 2014 through September 25, 2014 at the Region 10 office in Seattle, Washington and at the locations listed below, a copy of the public notice, draft permit, the statement of basis, the application, and relevant supporting materials:

Management Office (Info Desk)
The Confederated Tribes of the Warm Springs Reservation of Oregon
1233 Veterans Street
Warm Springs, Oregon 97761

Jefferson County Library
241 SE 7th Street
Madras, Oregon 97741

5.2 Response to Public Comments and Permit Issuance

The public comment period for this permit ran from August 27, 2014 to September 25, 2014. EPA received comments from Fred Tornatore of TSS Consultants. As required in 40 CFR § 71.11(e), EPA has considered the comments and has developed a response to each. The comments are summarized below along with a response that explains whether any change to the permit resulted and the reason why a change was or was not made. There was no public hearing requested or held. As required in 40 CFR § 71.11(i), EPA will notify the applicant and each person who has submitted comments or requested notice of the final permit decision.

Comments from TSS Consultants Submitted September 25, 2014:

1. Permit Condition 4.14 – Fuel Heat Input to Steam Output Ratio (FHISOR). The commenter states:

> *The subject permit instructs WSFPI to use the May 8, 2014 guidance document entitled "Procedure to Determine a Biomass Boiler's Fuel-Heat-Input-To-Steam-Output", to which WSFPI will comply. WSFPI does not have any comments on the appropriateness of the methodology presented in the May 8, 2014 version of the procedure but would like EPA to clarify the Statement of Basis to more accurately reflect the regulatory status of the procedure.*
>
> EPA Response – The May 8, 2014 EPA Region 10 technical memorandum entitled, "Procedure to Determine a Biomass Boiler's Fuel-Heat-Input-To-Steam-Output Ratio" is not a rule. It is not a proposed rule. It is a document that reflects our current thinking of how to determine a biomass boiler's FHISOR for the purpose of translating measured steam output into heat input for the purpose of conducting emission calculations. EPA most recently required a facility's use of it in a July 30, 2014 Title V permit issued to Empire Lumber Company for its planer mill on the Nez Perce Reservation. While EPA intends to continue to prescribe the procedure's use here and in future Title V permits, we do not intend to codify the procedure into the Code of Federal Regulations. The Title V and non-Title V permits we have drafted for WSFPI require you to follow the procedures outlined in the most recent version of the memorandum. Right now, the May 8, 2014 version is the one and only. The procedure can be accessed online at http://www.epa.gov/region10/pdf/air/technical/fhisor_memo.pdf.

2. Permit Condition 5.15 – Initial VOC Emission Factor Derivation Test. The commenter states:

> *Section 5.15 states that the greater of the two VOC emission factor determined by EPA Reference Method (RM) 25 and a modified RM 25A (as indicated in Sections 5.15.3 and 5.15.4 of the draft Title V permit) shall determine the VOC emission factor for the emissions inventory of PH5. We believe the use of RM 25 is inappropriate as the minimum detection limit is identified as 50 parts per million (Section 13.1) and the expected non-methane organic concentration is expected to be a fraction of the minimum detection limit of RM 25. We suggest deleting references to RM 25 and allow the use of RM 25A exclusively.*

EPA Response –WSFPI employed Method 25 and 25A concurrently to measure PH5 emissions in April 2006. In that instance, Method 25 reported three-run average VOC (as carbon) emissions of 61.4 ppmv which is above the 50 ppmv minimum detectable limit.

We have amended the permit to require only the use of Method 25 for reasons previously discussed in August 5, 2013 email to TSS Consultants memorialized in the administrative record for this permitting action. We stated,

> *EPA prefers use of Method 25 as it sees certain constituents that Method 25A does not. The permit that I've drafted dictates that both test methods be performed, and that the higher emission factor be employed. An acceptable alternative would be to simply perform Method 25. Condition 5.14.3 was written so as to improve the representativeness of Method 25 test results. I am attaching here a memo (October 27, 2006 memorandum from EPA's Paul Boys) that discusses the subject.*

3. Permit Conditions 6.2 and 7.3 and Statement of Basis, Appendix A – Request to Limit Temperature in Kilns. The commenter states:

In Appendix A, the Potential to Emit (PTE) for the Hazardous Air Pollutants emission factors for the kilns appear to be those for factors where the kilns exceed 200 degrees. As has been stated the WSFPI kilns will not exceed 200 degrees, so we propose that the < 200 degrees applicable HAPs emission factors be used in the PTE inventory. We request the inclusion of a permit condition in the non-Title V permit to prohibit the operation of the kilns above 200 F, as demonstrated by the use of a temperature recording system.

EPA Response – EPA has created Permit Conditions 2.3 in the underlying non-Title V permit No. R10NT500401 as follows, "The maximum one-hour block average dry bulb temperature (ºF) of heated air entering each lumber stack within KLN-N and KLN-W as determined pursuant to Condition 4.5 shall not exceed 200°F." This non-Title V permit condition has been incorporated into the Title V permit as Conditions 6.2 and 7.3 for KLN-N and KLN-W, respectively. Creation of these permit conditions does not result in the facility's potential HAP emissions becoming less than the major source thresholds. KLN-N and KLN-W HAP and VOC PTE calculations in Appendix A to this statement of basis have been amended to reflect the operating restrictions imposed by Permit Conditions 6.2 and 7.3.

4. Statement of Basis, Appendix A – PH5 Particulate Matter PTE. The commenter states:

In the PH5 table, PM 2.5 is the same as PM 10. This seems overly conservative, as PM2.5 is clearly a subset of PM. Our concern is that the public will view WSFPI's PM emissions as the sum of the PM, PM10 and PM2.5 emissions, which is not consistent with reality. WSFPI would appreciate EPA clarifying the discussion of the boiler PM emissions by indicating that PM, PM10, and PM2.5 emissions are not additive. Further, EPA should discuss that the PM emissions consist of PM10 and PM2.5 emissions and that the PM10 emissions consists completely of PM2.5 emissions.

EPA Response – $PM_{2.5}$ is not a subset of PM. In accordance with October 25, 2012 EPA rulemaking, PM does not include condensable particulate matter while PM_{10} and $PM_{2.5}$ do.[10] PM, PM_{10} and $PM_{2.5}$ all include filterable particulate matter.

Appendix A of the statement of basis documents WSFPI's potential to emit for the purpose of determining whether the facility is a major source and thus subject to the permitting requirements of 40 CFR Part 71 pursuant to 40 CFR § 71.3(a). The term "major source" defined in 40 CFR §71.2 refers to a stationary source's "potential to emit." Although EPA does not define the term

[10] See 77 FR 65107 (October 25, 2012) at http://www.gpo.gov/fdsys/pkg/FR-2012-10-25/pdf/2012-25978.pdf

"potential to emit" in 40 CFR Part 71, the term is defined by EPA at 40 CFR §§ 52.21(b)(4), 63.2 and 70.2 as follows:

> 40 CFR § 52.21. *Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.*
>
> (text underlined for emphasis)

> 40 CFR § 63.2. *Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.*
>
> (text underlined for emphasis)

> 40 CFR § 70.2. *Potential to emit means the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation is enforceable by the Administrator. This term does not alter or affect the use of this term for any other purposes under the Act, or the term "capacity factor" as used in title IV of the Act or the regulations promulgated thereunder.*
>
> (text underlined for emphasis)

EPA Form 5900-84 (Part 71 Application Form EMISS) defines "potential to emit" as follows[11]:

> *"Potential to emit" is defined as "the maximum capacity of a stationary source to emit any pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation is enforceable by the Administrator."* (text underlined for emphasis)

In each definition, EPA states clearly that the impact an air pollution control device has on an emission unit's potential to emit is considered only to the extent that the reductions are enforceable. The most stringent particulate matter (filterable) emission limitation PH5 must achieve is NSPS Db's 0.10 lb/MMBtu, and this limit applies equally in defining PM, PM_{10}, and $PM_{2.5}$ potential emissions. Because no emission limit applies to PH5's condensable particulate matter emissions, EPA defers to AP-42's uncontrolled emission factor of 0.017 lb/MMBtu to help define PM_{10} and $PM_{2.5}$ potential emissions. This condensable particulate matter contribution is in addition to the filterable portion. For these reasons, PH5's PM_{10} and $PM_{2.5}$ potential emissions are greater than its PM potential emissions. See Appendix A to this statement of basis for the PTE calculations.

[11] See http://www.epa.gov/airquality/permits/pdfs/emiss.pdf

5. Statement of Basis, Appendix A – CYC VOC PTE. The commenter states:

Regarding the WSFPI cyclones, the same VOC emission factor is used for all 6 cyclones. We want to point out here that CYC 1 to 4 involve green, undried wood, whereas CYC 5 and 6 involve wood that has been previously kiln-dried, thus the VOC emission factor should be much lower. We believe that the use of the kiln VOC emission factors and the wet conveying VOC emission factors for conveying dry wood residue represents a double counting of the VOC emissions. WSFPI suggests denoting that dry wood residue VOC emissions are negligible as most of the VOCs expected to be emitted are done during the drying operations.

EPA Response – EPA has amended VOC PTE calculations in Appendix A for CYC 5 and 6 to reflect a new emission factor that is based upon information presented in NCASI Technical Bulletin No. 768. The new factor was derived based upon data gathered while measuring VOC emissions resulting from chipping dry veneer trim (1.2% moisture content – southern yellow pine). See emission calculations in Appendix A. The resultant emission factor for CYC 5 and 6 is about 75 percent of the factor employed in the draft permitting action. EPA is not aware of any other testing data representative of VOC emissions resulting from the generation of dry wood residue from dried lumber or veneer.

6. Statement of Basis, Appendix A – PT PM, PM_{10} and $PM_{2.5}$ PTE. The commenter states:

In reviewing the PTE values calculated in the Plant Traffic (PT) table, we are very concerned how the particulate matter PTE was calculated, particularly where the number of trips and vehicle miles traveled. For example, the PT PTE table shows log delivery from the Gate to Yard 3. Log trucks do not delivery logs to Yard 3, but over 18,000 trips are shown in the table.

EPA Response – Because PT emissions are fugitive and thus not considered in determining whether WSFPI is a major source, EPA will accept the commenter's assertion without further documentation. EPA has amended the PT PTE calculations, and those changes are reflected in Table 3-1 above. Looking forward, EPA encourages WSFPI to submit a PTE inventory and all supporting calculations as part of its next Title V renewal application. See permit condition 2.13 and Part 71 Application Form EMISS.

7. Statement of Basis, Appendix A – General. The commenter states:

Although we realize that the PTE determination is inherently conservative, it must be noted that the actual emissions will be considerably lower, as the facility only operates one shift per day, and WSFPI lumber production is dependent on a much lower amount of timber coming from the reservation forest as determined by the Warm Springs Natural Resource Management Department.

We are also concerned about the general perception of such high numbers considering how much lower actual emissions will certainly be. Recently, opponents of biomass power have used the high PTE numbers found in various biomass power plant air quality permits in the attempt to discredit biomass power and the way EPA and states conduct permitting for biomass power (See: http://www.pfpi.net/wp-content/uploads/2014/04/PFPI-Biomass-is-the-New-Coal-April-2-2014.pdf)

EPA Response – Thank you for alerting us to this issue, but a core element of the Title V permitting process is for the permitting authority to determine regulatory applicability based upon the source's PTE. It is necessary for us to present our findings as evidence of regulatory applicability.

Comment from TSS Consultants Submitted September 26, 2014[12]

8. First Page of the Permit – Responsible Official. The commenter indicates that the title of the WSFPI official responsible for compliance has changed to "Chief Executive Officer."

EPA Response – EPA has amended the permit to reflect the change.

6. Changes to Permit

6.1 Changes to Permit Related to Comments Received

EPA has made three changes to the permit in response to public comments as detailed below. Underlined text has been added, and ~~strikethrough~~ text has been deleted.

1. First page of the permit.

***

Person Responsible for Compliance:	John Katchia Jr., ~~General Manager~~ Chief Executive Officer Warm Springs Forest Products Industries

***

2. Conditions 5.15 through 5.15.6 of the permit.

5.15 Initial VOC Emission Factor Derivation Test. No later than 120 days after issuance of this permit, or no later than 120 days after re-start of the boiler if it is shut-down (due to seasonal shortage of logs) at any time within the first 120 days after permit issuance, the permittee shall measure VOC emissions exiting the stack simultaneously using EPA Reference Methods (RM) 2 and ~~,25 and 25A~~ in Appendix A to 40 CFR part 60 while also measuring the boiler's steam generating rate to determine a VOC emission factor (lb/mlb steam). ~~The greater of the two emission factors (RM25 or 25A) shall be the test-derived emission factor for the purpose of calculating emissions pursuant to Condition **Error! Reference source not found.**~~.

***

~~5.15.4 RM25A shall be modified to include an evaluation of the flame ionization detector (FID) instrument for the effect of high moisture (a dilution system may be used); a calibration gas that has an oxygen content similar to the sampled stack gas or an evaluation of oxygen synergism effect on the FID instrument; and, methane as the calibration gas.~~

5.15.~~4~~5 The results of each test run shall be presented as an emission factor in units of lb VOC/mlb steam and calculated~~, RM25 separate from RM25A,~~ as follows:

$$\text{VOC EF} = 1.355 \times C \times \frac{3.118\times10^{-8}\ \text{lb/scf}}{\text{Ppmv}} \times Q \times \frac{60\ \text{min}}{\text{Hr}} / S$$

Where: VOC EF = VOC emission factor in units of lb/mlb steam;

1.355 = factor to convert $VOC_{\text{as carbon}}$ to $VOC_{\text{as compound emitted}}$;

C = $VOC_{\text{as carbon}}$ concentration as measured in units of ppmv;

3.118×10^{-8} lb/scf per ppmv $VOC_{\text{as carbon}}$ is relationship for expressing carbon concentration based upon ideal gas law at EPA standard conditions;

[12] Although EPA is not obligated to consider this comment as it was received after the close of the public comment period, EPA has chosen to accept it.

Q = Stack exhaust flow rate as measured in units of scf/min;

S = Steam generating rate as measured in units of mlb/hr; and

Values for C and Q shall be expressed on the same moisture basis.

5.15.5~~6~~ Calculate and report the arithmetic average of all valid test runs~~, RM25 separate from RM25A~~.

3. Conditions 6.2 and 7.3 of the permit.

6.2 The maximum one-hour block average dry bulb temperature (ºF) of heated air entering each lumber stack within KLN-N as determined pursuant to Condition 4.20 shall not exceed 200°F.

***

7.3 The maximum one-hour block average dry bulb temperature (ºF) of heated air entering each lumber stack within KLN-W as determined pursuant to Condition 4.20 shall not exceed 200°F.

6.2 Changes to Permit Unrelated to Comments Received

EPA has made two changes to the permit in response to public comments as detailed below. Underlined text has been added, and ~~strikethrough~~ text has been deleted.

1. Condition 3.40 of the permit.

3.40 ***

Original documents go to EPA at:

Part 71 Air Quality Permits
U.S. EPA - Region 10, AWT-150~~107~~
1200 Sixth Avenue, Suite 900
Seattle, WA 98101-3140

***

2. Condition 3.48 of the permit.

3.48 ***

Telephone: (206) 553-1331
~~Facsimile: (206) 553-0110~~
Attn: Part 71 Deviation Report

***

7. Abbreviations and Acronyms

Btu	British thermal units
CAA	Clean Air Act [42 U.S.C. section 7401 et seq.]
CAM	Compliance assurance monitoring
CFR	Code of Federal Regulations
CO	Carbon monoxide
COMS	Continuous opacity monitoring system
dscf	Dry standard cubic feet
EU	Emission Unit
EPA	United States Environmental Protection Agency (also U.S. EPA)
FARR	Federal Air Rules for Reservations

FR	Federal Register
gr/dscf	Grains per dry standard cubic foot (7,000 grains = 1 pound)
HAP	Hazardous air pollutant
hr	Hour
IEU	Insignificant emission unit
lb	Pound
1bm	Pound-mole
MACT	Maximum Achievable Control Technology
mm	One million
NESHAP	National Emission Standards for Hazardous Air Pollutants (40 CFR Parts 61 and 63)
NOx	Nitrogen oxides
PM	Particulate matter
PM10	Particulate matter less than or equal to 10 microns in aerodynamic diameter
ppmdv	Parts per million on a dry, volume basis
PSD	Prevention of significant deterioration
PTE	Potential to emit
S	Sulfur
SO_2	Sulfur dioxide
tpy	Tons per year
VOC	Volatile organic compound

Appendix A

EPA Estimation of Warm Springs Forest Products Industries Potential Air Pollutant Emissions

Statement of Basis
Title V Operating Permit
R10T5010100

Warm Springs, Oregon

Appendix A: Potential Emissions Inventory

Summary of Facility Non-HAP Potential to Emit

Potential to Emit, (tons per year)

Non-Fugitive Emissions[1], (tons per year)

	PH5	KLN-N	KLN-W	CYC	MNFA	MFA	PT	
	Biomass Boiler	Nardi Lumber Drying Kilns	Wellons Lumber Drying Kilns	Wood Residue Cyclones	Miscellaneous Non-Fugitive Activities	Miscellaneous Fugitive Activities	Plant Traffic	**Non-Fugitive Subtotal**
Carbon Monoxide (CO)	90.7							91
Lead (Pb)	0.03							0
Nitrogen Oxides (NO_X)	126.0							126
Particulate (PM)[2]	57.4	1.9	1.5	115.8	0			177
Inhalable Coarse Particulate (PM_{10})	67.1	1.9	1.5	98.4	0			169
Fine Particulate ($PM_{2.5}$)	67.1	1.9	1.5	57.9	0			128
Sulfur Dioxide (SO_2)	39.6							40
Volatile Organic Compounds (VOC)	21.5	109.5	22.0	92.3				245
Greenhouse Gas (CO_2e)	121,253							121,253

Fugitive Emissions, (tons per year)

	PH5	KLN-N	KLN-W	CYC	MNFA	MFA	PT	
	Biomass Boiler	Nardi Lumber Drying Kilns	Wellons Lumber Drying Kilns	Wood Residue Cyclones	Miscellaneous Non-Fugitive Activities	Miscellaneous Fugitive Activities	Plant Traffic	**Fugitive Subtotal**
Carbon Monoxide (CO)								0
Lead (Pb)								0
Nitrogen Oxides (NO_X)								0
Particulate (PM)[2]						52.9	1258.8	1,312
Respirable Particulate (PM_{10})						26.7	307.0	334
Fine Particulate ($PM_{2.5}$)						12.9	52.2	65
Sulfur Dioxide (SO_2)								0
Volatile Organic Compounds (VOC)								0
Greenhouse Gas (CO_2e)								0

All Emissions[3], (tons per year)

	PH5	KLN-N	KLN-W	CYC	MNFA	MFA	PT	
	Biomass Boiler	Nardi Lumber Drying Kilns	Wellons Lumber Drying Kilns	Wood Residue Cyclones	Miscellaneous Non-Fugitive Activities	Miscellaneous Fugitive Activities	Plant Traffic	**Plantwide PTE**
Carbon Monoxide (CO)	90.7							91
Lead (Pb)	0.03							0
Nitrogen Oxides (NO_X)	126.0							126
Particulate (PM)[2]	57.4	1.9	1.5	115.8	0	52.9	1258.8	1,488
Respirable Particulate (PM_{10})	67.1	1.9	1.5	98.4	0	26.7	307.0	503
Fine Particulate ($PM_{2.5}$)	67.1	1.9	1.5	57.9	0	12.9	52.2	194
Sulfur Dioxide (SO_2)	39.6							40
Volatile Organic Compounds (VOC)	21.5	109.5	22.0	92.3				245
Greenhouse Gas (CO_2e)	121,253							121,253

Notes:

[1] Only non-fugitive emissions are considered for this facility in determining Title V applicability given that it is a sawmill and not one of the 27 listed source categories required to consider fugitive emissions. See definition of "major source" at 40 CFR § 71.2.

[2] PM is not a pollutant considered in determining whether a source is subject to the requirement to obtain a Title V permit, however, PM emissions are considered in determining whether a facility/project is a major PSD source/modification and whether a source is subject to CAM.

[3] The "All Emissions" table sums the values in the "Non-Fugitive Emissions" and "Fugitive Emissions" tables.

Summary of Facility HAP Potential to Emit

Potential to Emit, (tons per year)

Hazardous Air Pollutants	PH5 Wellons Boiler	KLN-N Nardi Lumber Drying Kilns	KLN-W Wellons Lumber Drying Kilns	Single HAP Plantwide Totals
Trace Metal Compounds				
Antimony Compounds	4.53E-03			4.5E-03
Arsenic Compounds (including arsine)	1.26E-02			1.3E-02
Beryllium Compounds	6.31E-04			6.3E-04
Cadmium Compounds	2.35E-03			2.4E-03
Chromium Compounds (including hexavalent)	1.20E-02			1.2E-02
Cobalt Compounds	3.73E-03			3.7E-03
Lead Compounds (not elemental lead)	2.75E-02			2.8E-02
Manganese Compounds	9.18E-01			9.2E-01
Mercury Compounds[2]	2.01E-03			
Nickel Compounds	1.89E-02			1.9E-02
Phophorus	1.55E-02			1.5E-02
Selenium Compounds	1.61E-03			1.6E-03
Other Inorganic Compounds				
Chlorine	4.53E-01			4.5E-01
Hydrochloric acid (hydrogen chloride)	1.30E+00			1.3E+00
Organic Compounds				
Acetaldehyde	4.76E-01	5.29E+00	4.24E+00	1.0E+01
Acetophenone	1.84E-06			1.8E-06
Acrolein	2.30E+00	9.99E-02	7.99E-02	2.5E+00
Benzene	2.41E+00			2.4E+00
Bis(2-ethylhexyl)phthalate (DEHP)	2.70E-05			2.7E-05
Carbon tetrachloride	2.58E-02			2.6E-02
Chlorobenzene	1.89E-02			1.9E-02
Chloroform	1.61E-02			1.6E-02
Dibenzofurans[1]	1.07E-06			1.1E-06
2,4-Dinitrophenol	1.03E-04			1.0E-04
Ethyl benzene	1.78E-02			1.8E-02
Ethylene dichloride (1,2-Dichloroethane)	1.66E-02			1.7E-02
Formaldehyde	2.52E+00	1.31E-01	1.05E-01	2.8E+00
Methanol		5.70E+00	4.56E+00	1.0E+01
Methyl bromide (Bromomethane)	8.61E-03			8.6E-03
Methyl chloride (Chloromethane)	1.32E-02			1.3E-02
Methyl chloroform (1,1,1-trichloroethane)	1.78E-02			1.8E-02
Methylene chloride (Dichloromethane)	1.66E-01			1.7E-01
Naphthalene[1]	5.57E-02			5.6E-02
4-Nitrophenol	6.31E-05			6.3E-05
Pentachlorophenol	2.93E-05			2.9E-05
Phenol	2.93E-02			2.9E-02
Polychlorinated biphenyls (PCB)	4.55E-06			4.5E-06
Polycyclic Organic Matter (POM)	7.27E-02			7.3E-02
Propionaldehyde	3.50E-02	6.92E-02	5.53E-02	1.6E-01
Propylene dichloride (1,2-Dichloropropane)	1.89E-02			1.9E-02
Styrene	1.09E+00			1.1E+00
2,3,7,8-Tetrachlorodibenzo-p-dioxin[1]	4.93E-09			4.9E-09
Tetrachloroethylene (tetrachloroethene)	2.18E-02			2.2E-02
Toluene	5.28E-01			5.3E-01
Trichloroethylene (Trichloroethene)	1.72E-02			1.7E-02
2,4,6-Trichlorophenol	1.26E-05			1.3E-05
Vinyl chloride	1.03E-02			1.0E-02
Xylenes (inlc isomers and mixtures)	1.43E-02			1.4E-02
TOTAL[2]	12.6	11.3	9.0	

Predicted Highest Plantwide Single HAP	~~10.3~~	tons per year, methanol
Predicted Plantwide HAP Total	~~32.9~~	tons per year, based on summing estimates
Highest Plantwide Single HAP PTE	9	tons per year, based on emission limit in FARR Non-Title V permit R10NT50(
Plantwide HAP PTE	24	tons per year, based on emission limit in FARR Non-Title V permit R10NT50(

[1] designates a HAP that is subject individually to the 10 tpy major source threshold, but that is also one of several polycyclic organic matter (POM) compounds that, in aggregate, are subject to the same 10 tpy major source threshold.

[2] Because dibenzofurans, naphthalene and 2,3,7,8-Tetrachlorodibenzo-p-dioxin (one of several dibenzodioxins) are accounted for individually and in the calculation of POM EF, their individual contribution here is discounted so as to avoid double-counting.

Non-HAP Potential to Emit

Emission Unit: **PH5**
Description: Wellons Boiler. Model Number NB234. Serial Number B2329-0503.
Two-cell pile-burning design with automatic rotating grates. Overfeed fuel delivery.
Combustion air introduced below grates and also above grates at 2 separate heights.
See combustor cell system at http://www.wellons.ca/energycombustors.html
Maximum Steam Production: 80,000 lb/hr at 250 psig and 750°F
Particulate Matter Control Device: Multiclones and electrostatic precipitator (required by this Title V permit)
Fuel: Biomass (hog fuel, wood residue or purchased forest slash)
Commence Construction: After 06/09/84 but before 02/28/05. NSPS Subpart Db and PM limit applicability.
Startup: 12/27/2005
Design Maximum Heat Input Capcity: 131 MMBtu/hr
Operation: 8760 hours per year

NON-FUGITIVE EMISSIONS

Potential to Emit, (tons per year)

Criteria Pollutant Emissions	EF (lb/MMBtu)	PTE (tpy)	EF Reference
Carbon Monoxide (CO)	0.158	90.7	2 - CO EF is based upon site-specific test results; higher value for two runs.
Lead (Pb)	0.000048	0.03	1 - Pb Option 1 because no specific limits apply.
Nitrogen Oxides (NO_X)[1]	0.3156	~~181.1~~	3 - NO_X EF is based upon site-specific test results; the highest test value (three-run average) of four stack tests.
Particulate (PM)	0.10	57.4	1 - PM Option 1 because boiler is subject to New Source Performance Standards (NSPS), Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. See 40 CFR § 60.43b(c)(1) for 0.10 lb/MMBtu PM emission limit. PM emissions are the "filterable" fraction quantified via EPA Reference Method 5. PM emissions do not include the "condensible" fraction. See EPA final rulemaking in the October 25, 2012 Federal Register, pages 65107-65119, at http://www.gpo.gov/fdsys/pkg/FR-2012-10-25/pdf/2012-25978.pdf. EF derived from stack testing conducted April 2006 and April 2009 are not employed to determine PTE because (a) control devices (multiclones and electrostatic precipitator (ESP)) were employed to reduce PM emission during the test and (b) the source is not required to achieve the emission rates observed.
Inhalable Coarse Particulate (PM_{10})	0.117	67.1	1 - PM_{10} Option 1 because boiler is subject to NSPS Db PM limit of 0.010 lb/MMBtu (assume all PM_{10}) and condensible fraction is 0.017 lb/MMBtu according to AP-42.
Fine Particulate ($PM_{2.5}$)	0.117	67.1	1 - $PM_{2.5}$ Option 1 because boiler is subject to NSPS Db PM limit of 0.010 lb/MMBtu (assume all $PM_{2.5}$) and condensible fraction is 0.017 lb/MMBtu according to AP-42.
Sulfur Dioxide (SO_2)	0.069	39.6	1 - SO_2 Option 5. Because Option 1's FARR combustion source stack 500 ppm SO_2 emission limit is more stringent than Option 2's FARR solid fuel sulfur limit of 2% by weight (dry), Option 2 is not further considered. For Option 1, a sulfur content in the wood of 0.5% by weight (dry) would be necessary along with 100% conversion to SO_2 to generate 500 ppm SO_2 concentration in the stack. Because neither are reasonable worst-case assumptions, Option 1 is not further considered. Because Option 6 is simply an average of values derived from stack test results, Option 6 is not further considered. For Options 3, 4 and 5, all assume a reasonable worst-case sulfur content in the wood of 0.2% by weight (dry). The difference between Options 3, 4 and 5 rests with the sulfur-to-SO_2 assumed conversion rate. Option 3 reflects 100% conversion, Option 4 represents 10% conversion and Option 5 represents 15% conversion. Option 5 represents a reasonable worst-case estimation of PTE.
Volatile Organic Compounds (VOC)[1]	0.042	~~24.3~~	2 - VOC EF is based upon site-specific test results; the 90th percentile value for three runs. The 90th percentile value (as carbon) of 0.0312 lb/MMBtu is converted to 0.042 lb/MMBtu (as compound emitted) assuming a weighted average VOC molecular weight of 64.7 lb/lb-mol and 4 carbon atoms per compound. The calculation to convert VOC (as carbon) to VOC (as compound) is displayed below.

Greenhouse Gas Emissions (CO_2 Equivalent)	EF (lb/MMBtu)	PTE (tpy)	EF Reference
Carbon Dioxide (CO_2)	206.8	118,658	1 - CO_2 Option 2 because the GHG Reporting Rule (40 CFR 98) is considered the primary reference for estimating GHG emissions when preparing or processing permit applications.
Methane (CH_4)	1.764	1,012	1 - CH_4 Option 2 because the GHG Reporting Rule (40 CFR 98) is considered the primary reference for estimating GHG emissions when preparing or processing permit applications.
Nitrous Oxide (N_2O)	2.759	1,583	1 - N_2O Option 2 because the GHG Reporting Rule (40 CFR 98) is considered the primary reference for estimating GHG emissions when preparing or processing permit applications.
TOTAL		121,253	

[1] NO_X and VOC PTE restricted by Title V permit R10T5010100 as follows:
NO_X PTE: 126 tons per year
VOC PTE: 21.5 tons per year

EF Reference	Description
1	EPA Region 10 Non-HAP Potential to Emit Emission Factors for Biomass Boilers Located in Pacific Northwest Indian Country, May 8, 2014.
2	June 9, 2006 Source Emission Evaluation Report. AMTEST Air Quality, LLC. Warm Springs Forest Products Industries (WSFPI). Wellons Hog Fuel Boiler #5. EPA Permit R10T5010000. Warm Springs, Oregon. April 6-7, 2006.
3	June 20, 2008 Golden Specialty Consulting, Ltd. Air Quality Test Report. Warm Springs Forest Products Industries (WSFPI). Wellons Hog Fuel Boiler PH-5. EPA Perimt R10T5010000. Warm Springs, Oregon. The May 28, 2008 stack test reported highest emissions among stack testing conducted April 2006, April 2007, May 2008 and May 2009. Stack testing for NO_X has not been conducted since.

Appendix A: Potential Emissions Inventory

Calculation to convert VOC (as carbon) to VOC (as compound).

VOC (as weighted-average VOC) = (VOC_C) X [($MW_{wt\text{-}avg\ VOC}$) / (MW_C)] X [($\#C_C$) / ($\#C_{wt\text{-}avg\ VOC}$)]

where:

VOC_C equals "0.0312 lb/MMBtu" from June 9, 2006 Source Emission Evaluation Report. Value represents 90th percentile value among three Method 25 test runs.

$MW_{wt\text{-}avg\ VOC}$ equals "64.689 lb/lb-mol" and is the weighted-average molecular weight for VOC assuming speciated organic compound ratios supported by AP-42

MW_C equals "12.0110 lb/lb-mol" and represents the molecular weight for carbon

$\#C_C$ equals "1" as the single carbon atom was the "basis" for which Method 25 VOC test results were determined

$\#C_{wt\text{-}avg\ VOC}$ equals "3.975" and is the weighted-average number of carbon atoms present in VOC assuming speciated organic compound ratios supported by AP-42 Table 1.6-3

Calculating value for VOC (as weighted-average VOC):

VOC (as carbon):	0.0312	lb/MMBtu
$MW_{wt\text{-}avg\ VOC}$:	64.689	lb/lb-mol
MW_C:	12.011	lb/lb-mol
$\#C_C$:	1	
$\#C_{wt\text{-}avg\ VOC}$:	3.975	
VOC (as weighted average VOC)	0.042	lb/MMBtu

Factor to convert VOC_C to VOC (as weighted average VOC) = 1.355

The first two columns of the following table are extracted from AP-42, September 2003. Table 1.6-3. The third and fourth columns were created based upon information widely available over the internet. The fifth and sixth columns illustrate calculations necessary to determine weighted-average molecular weight and weighted-average number of carbon atoms comprising VOC emissions resulting from wood residue combustion.

Wood Residue Combustion Organic Compounds	EF (lb/MMBtu) (lb/MMBtu)	MW lb/lb-mol	Number of Carbon Atoms	EF x MW	EF X #C atoms
Acenaphthene	9.10E-07	154.21	12	1.40E-04	1.09E-05
Acenaphthylene	5.00E-06	152.19	12	7.61E-04	6.00E-05
Acetaldehyde	8.30E-04	44.05	2	3.66E-02	1.66E-03
Acetone	1.90E-04	58.08	3	1.10E-02	5.70E-04
Acetophenone	3.20E-09	120.15	8	3.84E-07	2.56E-08
Acrolein	4.00E-03	56.06	3	2.24E-01	1.20E-02
Anthracene	3.00E-06	178.23	14	5.35E-04	4.20E-05
Benzaldehyde	8.50E-07	106.12	7	9.02E-05	5.95E-06
Benzene	4.20E-03	78.11	6	3.28E-01	2.52E-02
Benzo(a)anthracene	6.50E-08	228.29	18	1.48E-05	1.17E-06
Benzo(a)pyrene	2.60E-06	252.31	20	6.56E-04	5.20E-05
Benzo(b)fluoranthene	1.00E-07	252.31	20	2.52E-05	2.00E-06
Benzo(e)pyrene	2.60E-09	252.31	20	6.56E-07	5.20E-08
Benzo(g,h,i)perylene	9.30E-08	276.33	22	2.57E-05	2.05E-06
Benzo(j,k)fluoranthene	1.60E-07	202.26	16	3.24E-05	2.56E-06
Benzo(k)fluoranthene	3.60E-08	252.31	20	9.08E-06	7.20E-07
Benzoic acid	4.70E-08	122.12	7	5.74E-06	3.29E-07
Bis(2-ethylhexyl)phthalate (DEHP)	4.70E-08	390.56	24	1.84E-05	1.13E-06
Bromomethane (Methyle bromide)	1.50E-05	94.94	1	1.42E-03	1.50E-05
2-Butanone (MEK)	5.40E-06	72.11	4	3.89E-04	2.16E-05
Carbazole	1.80E-06	167.21	12	3.01E-04	2.16E-05
Carbon tetrachloride	4.50E-05	153.82	1	6.92E-03	4.50E-05
Chlorobenzene	3.30E-05	112.56	6	3.71E-03	1.98E-04
Chloroform	2.80E-05	119.38	1	3.34E-03	2.80E-05
Chloromethane (Methyl chloride)	2.30E-05	50.49	1	1.16E-03	2.30E-05
2-Chloronaphthalene	2.40E-09	162.62	10	3.90E-07	2.40E-08
2-Chlorophenol	2.40E-08	128.56	6	3.09E-06	1.44E-07
Chrysene	3.80E-08	228.28	18	8.67E-06	6.84E-07
Crotonaldehyde	9.90E-06	70.09	4	6.94E-04	3.96E-05
Decachlorobiphenyl	2.70E-10	498.6584	12	1.35E-07	3.24E-09
Dibenzo(a,h)anthracene	9.10E-09	278.35	22	2.53E-06	2.00E-07
1,2-Dibromoethene	5.50E-05	185.85	2	1.02E-02	1.10E-04
Dichlorobiphenyl	7.40E-10	223.09792	12	1.65E-07	8.88E-09
1,2-Dichloroethane (Ethylene dichloride)	2.90E-05	98.96	2	2.87E-03	5.80E-05
Dichloromethane (Methylene chloride)	2.90E-04	84.93	2	2.46E-02	5.80E-04
1,2-Dichloropropane (Propylene dichloride)	3.30E-05	122.99	3	4.06E-03	9.90E-05
2,4-Dinitrophenol	1.80E-07	184.11	6	3.31E-05	1.08E-06
Ethyl benzene	3.10E-05	106.17	8	3.29E-03	2.48E-04
Fluoranthene	1.60E-06	202.26	16	3.24E-04	2.56E-05
Fluorene	3.40E-06	166.22	13	5.65E-04	4.42E-05
Formaldehyde	4.40E-03	30.03	1	1.32E-01	4.40E-03
Heptachlorobiphenyl	6.60E-11	395.32322	12	2.61E-08	7.92E-10
Hexachlorobiphenyl	5.50E-10	360.87816	12	1.98E-07	6.60E-09
Hexanal	7.00E-06	100.15888	6	7.01E-04	4.20E-05
Heptachlorodibenzo-p-dioxins	2.00E-09	425.30614	12	8.51E-07	2.40E-08
Heptachlorodibenzo-p-furans	2.40E-10	409.30674	12	9.82E-08	2.88E-09
Hexachlorodibenzo-p-dioxins	1.60E-06	390.82	12	6.25E-04	1.92E-05
Hexachlorodibenzo-p-furans	2.80E-10	374.86168	12	1.05E-07	3.36E-09
Indeno(1,2,3-cd)pyrene	8.70E-08	326.34	22	2.84E-05	1.91E-06
Isobutyraldehyde	1.20E-05	72.10572	4	8.65E-04	4.80E-05
2-Methylnaphthalene	1.60E-07	142.20	11	2.28E-05	1.76E-06
Monochlorobiphenyl	2.20E-10	187.64492	12	4.13E-08	2.64E-09
Naphthalene	9.70E-05	128.17	10	1.24E-02	9.70E-04
2-Nitrophenol	2.40E-07	139.11	6	3.34E-05	1.44E-06
4-Nitrophenol	1.10E-07	139.11	6	1.53E-05	6.60E-07
Octachlorodibenzo-p-dioxins	6.60E-08	459.7512	12	3.03E-05	7.92E-07
Octachlorodibenzo-p-furans	8.80E-11	443.7518	12	3.91E-08	1.06E-09
Pentachlorodibenzo-p-dioxins	1.50E-09	356.41602	12	5.35E-07	1.80E-08
Pentachlorodibenzo-p-furans	4.20E-10	340.41662	12	1.43E-07	5.04E-09
Pentachlorobiphenyl	1.20E-09	326.4331	12	3.92E-07	1.44E-08
Pentachlorophenol	5.10E-08	266.34	6	1.36E-05	3.06E-07
Perylene	5.20E-10	252.31	20	1.31E-07	1.04E-08
Phenanthrene	7.00E-06	178.23	14	1.25E-03	9.80E-05
Phenol	5.10E-05	94.11	6	4.80E-03	3.06E-04
Propanal	3.20E-06	58.08	3	1.86E-04	9.60E-06
Propionaldehyde	6.10E-05	58.08	3	3.54E-03	1.83E-04
Pyrene	3.70E-06	202.25	16	7.48E-04	5.92E-05

Styrene	1.90E-03	104.15	8	1.98E-01	1.52E-02
2,3,7,8-Tetrachlorodibenzo-p-dioxins	8.60E-12	321.97096	12	2.77E-09	1.03E-10
Tetrachlorodibenzo-p-dioxins	4.70E-10	321.97096	12	1.51E-07	5.64E-09
2,3,7,8-Tetrachlorodibenzo-p-furans	9.00E-11	305.97156	12	2.75E-08	1.08E-09
Tetrachlorodibenzo-p-furans	7.50E-10	305.97156	12	2.29E-07	9.00E-09
Tetrachlorobiphenyl	2.50E-09	291.98804	12	7.30E-07	3.00E-08
Tetrachloroethene (Tetrachloroethylene)	3.80E-05	165.83	2	6.30E-03	7.60E-05
o-Tolualdehyde	7.20E-06	120.15	8	8.65E-04	5.76E-05
p-Tolualdehyde	1.10E-05	120.15	8	1.32E-03	8.80E-05
Toluene	9.20E-04	92.14	7	8.48E-02	6.44E-03
Trichlorobiphenyl	2.60E-09	257.54298	12	6.70E-07	3.12E-08
1,1,1-trichloroethane (Methyl chloroform)	3.10E-05	133.40	2	4.14E-03	6.20E-05
Trichloroethene (Trichloroethylene)	3.00E-05	131.39	2	3.94E-03	6.00E-05
Trichlorofluoromethane	4.10E-05	137.37	1	5.63E-03	4.10E-05
2,4,6-Trichlorophenol	2.20E-08	197.45	6	4.34E-06	1.32E-07
Vinyl chloride	1.80E-05	62.50	2	1.13E-03	3.60E-05
o-Xylene	2.50E-05	106.16	8	2.65E-03	2.00E-04
TOTAL	1.75E-02			1.13E+00	6.96E-02
				64.689	3.975

weighted-average molecular weight of VOC

weighted-average number of carbon atoms comprising VOC

Non-HAP Potential to Emit

Emission Unit: **KLN-N**
Description: Lumber drying
Control Device: None
Work Practice: None
Fuel: None - indirect steam provided by Wellons Boiler
Predominant Species Dried: Douglas Fir, Hemlock, Ponderosa Pine, White Fir
Installed: 5 single-track Nardi kilns (No.'s 1 - 5) installed 1997
Annual Capacity: 76,850 mbf/yr

NON-FUGITIVE EMISSIONS

Potential to Emit, (tons per year)

Pollutant Emissions	EF (lb/mbf)	PTE (tpy)	EF Reference
Carbon Monoxide (CO)	0	0	
Lead (Pb)	0	0	
Nitrogen Oxides (NO_X)	0	0	
Particulate (PM)	0.05	1.9	1 - Because the facility has the ability to dry both resinous and non-resinous softwood species select the higher of the two EF to determine PTE. The non-resinous softwood EF is higher.
Respirable Particulate (PM_{10})	0.05	1.9	1 - Because the facility has the ability to dry both resinous and non-resinous softwood species select the higher of the two EF to determine PTE. The non-resinous softwood EF is higher.
Fine Particulate ($PM_{2.5}$)	0.05	1.9	1 - Because the facility has the ability to dry both resinous and non-resinous softwood species select the higher of the two EF to determine PTE. The non-resinous softwood EF is higher.
Sulfur Dioxide (SO_2)	0	0	
Volatile Organic Compounds (VOC)	2.8505	109.5	2 - Because the facility has the ability to dry resinous and non-resinous softwood species but at temperatures less than or equal to 200^0F as restricted by non-Title V permit No. R10NT500401, select the highest WPP1 VOC EF from among all softwood species for drying at less than or equal to 200^0F. The Western White Pine EF is highest.

Greenhouse Gas Emissions (CO_2 Equivalent)	EF (lb/mbf)	PTE (tpy)	EF Reference
Carbon Dioxide (CO_2)	0	0	
Methane (CH_4)	0	0	
Nitrous Oxide (N_2O)	0	0	
TOTAL	0	0	

EF Reference	Description
1	EPA Region 10 Particulate Matter Potential to Emit Emission Factors for Activities at Sawmills, Excluding Boilers, Located in Pacific Northwest Indian Country, May 8, 2014.
2	EPA Region 10 HAP and VOC Emission Factors for Lumber Drying, December 2012.

Abbreviations
ACDP: air construction discharge permit
mbf: 1,000 board feet lumber
ODEQ: Oregon Department of Environmental Conservation
WPP1: Wood Products Protocol 1

Non-HAP Potential to Emit

Emission Unit: **KLN-W**
Description: Lumber drying
Control Device: None
Work Practice: None
Fuel: None - indirect steam provided by Wellons Boiler
Predominant Species Dried: Douglas Fir, Hemlock, Ponderosa Pine, White Fir
Installed: 2 double-track Wellons kilns (No.'s 6A - 7B) installed 2000
Annual Capacity: 61,480 mbf/yr

NON-FUGITIVE EMISSIONS

Potential to Emit, (tons per year)

Criteria Pollutant Emissions	EF (lb/mbf)	PTE (tpy)	EF Reference
Carbon Monoxide (CO)	0	0	
Lead (Pb)	0	0	
Nitrogen Oxides (NO_X)	0	0	
Particulate (PM)	0.05	1.5	1 - Because the facility has the ability to dry both resinous and non-resinous softwood species select the higher of the two EF to determine PTE. The non-resinous softwood EF is higher.
Respirable Particulate (PM_{10})	0.05	1.5	1 - Because the facility has the ability to dry both resinous and non-resinous softwood species select the higher of the two EF to determine PTE. The non-resinous softwood EF is higher.
Fine Particulate ($PM_{2.5}$)	0.05	1.5	1 - Because the facility has the ability to dry both resinous and non-resinous softwood species select the higher of the two EF to determine PTE. The non-resinous softwood EF is higher.
Sulfur Dioxide (SO_2)	0	0	
Volatile Organic Compounds (VOC)[1]	2.8505	~~87.6~~	2 - Because the facility has the ability to dry resinous and non-resinous softwood species but at temperatures less than or equal to 200^0F as restricted by non-Title V permit No. R10NT500401, select the highest WPP1 VOC EF from among all softwood species for drying at less than or equal to 200^0F. The Western White Pine EF is highest.

Greenhouse Gas Emissions (CO_2 Equivalent)	EF (lb/mbf)	PTE (tpy)	EF Reference
Carbon Dioxide (CO_2)	0	0	
Methane (CH_4)	0	0	
Nitrous Oxide (N_2O)	0	0	
TOTAL	0	0	

[1] VOC PTE restricted by Title V permit R10T5010100 as follows:
[1] VOC PTE: 22.0 tons per year

EF Reference	Description
1	EPA Region 10 Particulate Matter Potential to Emit Emission Factors for Activities at Sawmills, Excluding Boilers, Located in Pacific Northwest Indian Country, May 8, 2014.
2	EPA Region 10 HAP and VOC Emission Factors for Lumber Drying, December 2012.

Abbreviations
ACDP: air construction discharge permit
mbf: 1,000 board feet lumber
ODEQ: Oregon Department of Environmental Conservation
WPP1: Wood Products Protocol 1

Non-HAP Potential to Emit

Emission Unit: **CYC**

Description: Wood Residue Cyclones. Six cyclones (CYC1 through CYC6) employed to capture pneumatically conveyed wood residue and deposit into storage bins.

NON-FUGITIVE EMISSIONS

Potential to Emit, (tons per year)

Emissions Generating Activity[1]	Annual Capacity	EF				PTE			
		PM	PM_{10}	$PM_{2.5}$	VOC	PM	PM_{10}	$PM_{2.5}$	VOC
	(bdt/yr)	(lb/bdt)				(tpy)			
CYC1	328,409	0.5	0.425	0.25	0.4283	82.1	69.8	41.1	70.3
CYC2	13,701	0.5	0.425	0.25	0.4283	3.4	2.9	1.7	2.9
CYC3		0.5	0.425	0.25	0.4283	0.0	0.0	0.0	0.0
CYC4		0.5	0.425	0.25	0.4283	0.0	0.0	0.0	0.0
CYC5	9,084	0.5	0.425	0.25	0.3140	2.3	1.9	1.1	1.4
CYC6	112,040	0.5	0.425	0.25	0.3140	28.0	23.8	14.0	17.6
					TOTAL	115.8	98.4	57.9	92.3

PM, PM_{10} and $PM_{2.5}$ EF Basis	EPA Region 10 Particulate Matter Potential to Emit Emission Factors for Activities at Sawmills, Excluding Boilers, Located in Pacific Northwest Indian Country, May 8, 2014.
CYC 1 - 4 VOC EF Basis	NCASI Technical Bulletin No. 723 entitled, "Laboratory and Limited Field Measurements of VOC Emissions from Wood Residuals," September 1996. Assume processing of ponderosa pine logs harvested during season resulting in highest emissions. To convert NCASI emission factor from units of carbon to units of propane (estimate of VOC emitted), multiply by propane mass conversion factor of 1.2238. For further explanation for expressing emissions as propane, see Interim VOC Measurement Protocol for the Wood Products Industry - July 2007. See also Appendix C of NCASI's Technical Bulletin No. 991 entitled, "Characterization, Measurement, and Reporting of Volaitle Organic Compounds Emitted from Southern Pine Wood Products Sources," September 2011. For ponderosa pine chips, (0.35 lb C/odt) X 1.2238 = 0.4283 lb VOC (as propane)/odt. In the absence of emissions testing data for either ponderosa pine sawdust or shavings, assume emission factor for ponderosa pine chips. The actual sawdust and shavings emission factor is likely higher than chip-derived estimate based upon comparative emissions testing data for douglas fir.
CYC 5 - 6 VOC EF Basis	NCASI Technical Bulletin No. 768 entitled, "Volatile Organic Compound Emissions from Wood Products Manufacturing Facilities, Part I - Plywood," January 1999. Mill 165. Source 1WD1 - southern yellow pine veneer chipping. To convert NCASI emission factor from units of carbon to units of propane (estimate of VOC emitted), multiply by propane mass conversion factor of 1.2238. For further explanation for expressing emissions as propane, see Interim VOC Measurement Protocol for the Wood Products Industry - July 2007. See also Appendix C of NCASI's Technical Bulletin No. 991 entitled, "Characterization, Measurement, and Reporting of Volatile Organic Compounds Emitted from Southern Pine Wood Products Sources," September 2011. (0.2566 lb C/odt) X 1.2238 = 0.3140 lb VOC (as propane)/odt. EPA is not aware of any other emissions testing data for activities generating wood residue from dry lumber or veneer. See calculation for the determination of 0.2566 lb C/odt EF below.
Annual Capacity Basis	Initial Part 71 2005 permitting action

Calculation to Determine CYC 5 & 6 VOC EF

Study: NCASI TB 768. Emission source 1WD1 - southern yellow pine veneer chipping. Mill No. 165. Emissions presented on page 156, operating rates on page 78.

A	B	C	D
VOC EF presented in units of lb C/MSF 3/8" *finished board production rate* lb C/MSF 3/8"	Average Finished Board Production Rate MSF 3/8"/hr	Average Board Trim Processed Rate MSF 3/8"/hr	Moisture Content % dry basis
0.059	89.9	10.0	1.2

To convert EF above from lb C/MSF 3/8" *finished board production rate* to lb C/MSF 3/8" *board trim processed* , multiply EF by ratio of average finished board production rate to average board trim processed rate. In other words, EF in units of "lb C/MSF 3/8" board trim processed" = **A** X (**B**/**C**).

E
VOC EF presented in units of lb C/MSF 3/8" *board trim processed*
0.5304

To convert EF above from units of lb C/MSF 3/8" at observed moisture content (MC) - dry basis to units of lb C/ton at observed MC - dry basis, employ conversion factor of 0.544/[1+(0.15-observed MC)] ton C/MSF 3/8". In other words, EF in units of "lb C/ton" at observed MC - dry basis = **E** X [0.544/[1+(0.15-**D**/100)]

Basis for 0.544 ton/MSF 3/8" (at 15% moisture content - dry basis) conversion factor:
http://www.ruraltech.org/projects/conversions/briggs_conversions/briggs_append2/appendix02_combined.pdf

F
VOC EF presented in units of lb C/ton board trim processed
0.2536

To convert EF above into units of lb C/oven dry ton (ODT), divide EF by [1-(observed MC-0)]. In other words, EF in units of "lb C/ODT" = **F** / [1-(**D**/100-0)]

VOC EF presented in units of lb C/odt board trim processed
0.2566

[1] Glossary of Emissions Generating Activity

CYC1 - Cyclone No. 1. Medium efficiency product recovery cyclone to capture green chips and deposit into Bin B. Chips can be transferred west to Bin A (double bin). Cyclone No. 1 located on top of Bin B. See Item #9 on March 22, 2013 WSFPI map.
CYC2 - Cyclone No. 2. Medium efficiency product recovery cyclone to capture green sawdust and deposit into Bin D. Sawdust can be transferred west to Bin C. Cyclone No. 2 located on top of Bin D. See Item #9 on March 22, 2013 WSFPI map.
CYC3 - Cyclone No. 3. Medium efficiency product recovery cyclone to capture green chips from 48" Chipper and deposit into Surge Bin. Cyclone No. 3 is eastern-most cyclone located on top of Surge Bin. Surge Bin also mechanically receives green chips from 60" Chipper and 75" Chipper. Green chips in Surge Bin eventually blown to CYC1. See Item #6 on March 22, 2013 WSFPI map.
CYC4 - Cyclone No. 4. Medium efficiency product recovery cyclone to capture green chips from 60" Chipper and deposit into Surge Bin. Cyclone No. 4 is western-most cyclone located on top of Surge Bin. Surge Bin also mechanically receives green chips from 60" Chipper and 75" Chipper. Green chips in Surge Bin eventually blown to CYC1. CYC4 in not currently in service. See Item #6 on March 22, 2013 WSFPI map.
CYC5 - Cyclone No. 5. Medium efficiency product recovery cyclone to capture dry shavings from "planer exhaust fan" and deposit into Bin E. Shavings can be transferred east to Bin F. Cyclone No. 5 located on top of Bin E. See Item #40 "planer cyclone" on March 22, 2013 WSFPI map.
CYC6 - Cyclone No. 6. Medium efficiency product recovery cyclone to capture dry shavings from "shaver exhaust fan" and deposit into Bin H. Shavings can be transferred south to Bin G. Cyclone No. 6 located on top of Bin H. See Item #45 "planer trimmer shaver cyclone" on March 22, 2013 WSFPI map.

Abbreviations

odt: oven dry ton

NCASI: National Council for Air and Stream Improvement

Non-HAP Potential to Emit

Emission Unit: **MNFA**

Description: Miscellaneous Non-Fugitive Activities. Activities occurring inside a building that generate wood residue that is not pneumatically conveyed to a product recovery device.

NON-FUGITIVE EMISSIONS

Potential to Emit, (tons per year)

Emissions Generating Activity	Annual Capacity	EF				PTE			
		PM	PM_{10}	$PM_{2.5}$	VOC	PM	PM_{10}	$PM_{2.5}$	VOC
		(lb/ton log, lb/bdt or lb/mbf; as applicable)				(tpy)			
Wet Material Sawing (inside building)	1,477,974 tons log/yr	0	0	0		0	0	0	0
				TOTAL		0	0	0	

PM, PM_{10} and $PM_{2.5}$ EF Basis: EPA Region 10 Particulate Matter Potential to Emit Emission Factors for Activities at Sawmills, Excluding Boilers, Located in Pacific Northwest Indian Country, May 8, 2014.

Annual Capacity Basis: Initial Part 71 2005 permitting action

Abbreviations
bdt: bone dry ton
mbf: 1,000 board feet lumber

Non-HAP Potential to Emit

Emission Unit: **MFA**

Description: Miscellaneous Fugitive Activities. Activities occurring outside a building or storage structure that generate, transport or store wood residue.

FUGITIVE EMISSIONS

Potential to Emit, (tons per year)

Emissions Generating Activity	Annual Capacity		EF				PTE			
			PM	PM_{10}	$PM_{2.5}$	VOC	PM	PM_{10}	$PM_{2.5}$	VOC
			(lb/bdt, ton/acre-yr, tons log/yr; as applicable)				(tpy)			
Loadout of Green Chips Bins A and B (no side shields). Area 9.	328,409	bdt/yr	0.00075	0.00035	0.00005		0.12	0.06	0.01	0
Loadout of Sawdust from Bins C & D (no side shields). Area 9.	13,701	bdt/yr	0.00075	0.00035	0.00005		0.01	0.00	0.00	0
Loadout of Lodgepole Pine Green Chips from Conveyor. Area 14.		bdt/yr	0.00075	0.00035	0.00005		0.00	0.00	0.00	0
Loadout of Shavings from Bin E (no side shields). Area 40.	9,084	bdt/yr	0.0015	0.0007	0.0001		0.01	0.00	0.00	0
Loadout of Hogged Trim Ends from Bins F and G (no side shields). Areas 40 and 45A.	112,040	bdt/yr	0.0015	0.0007	0.0001		0.08	0.04	0.01	0
Sawdust Mechanical Conveyance to Surge Bin		bdt/yr	0.00075	0.00035	0.00005		0.00	0.00	0.00	0
Bark Mechanical Conveyance to Hog (Est. 6 drops)	354,182	bdt/yr	0.00075	0.00035	0.00005		0.13	0.37	0.05	0
Hog Mechanical Conveyance to Hog Fuel Pile (Est. 6 drops)	354,182	bdt/yr	0.00075	0.00035	0.00005		0.80	0.37	0.05	0
Drop Lodgepole Pine from Conveyor onto Ground		bdt/yr	0.00075	0.00035	0.00005		0.00	0.00	0.00	0
Bark Front-end Loader ???	354,182	bdt/yr	0.0015	0.0007	0.0001		0.27	0.12	0.02	0
Hog Fuel Dump in Yard ???	35,419	bdt/yr	0.0015	0.0007	0.0001		0.03	0.01	0.00	0
Hog Fuel Storage Pile (Wind Erosion)	1	acre-yr	0.38	0.19	0.095		0.4	0.2	0.1	0
Log Yards No.'s 1, 2 and 3 (Wind Erosion)	17.9	acre-yr	0.38	0.19	0.095		6.8	3.4	1.7	0
Log Bucking	1,477,974	tons log/yr	0.035	0.0175	0.00875		25.9	12.9	6.5	0
Log Debarking	1,477,974	tons log/yr	0.024	0.012	0.006		17.7	8.9	4.4	0
75" Lodgepole Pine Chipper (wet material drop)		bdt/yr	0.00075	0.00035	0.00005		0.6	0.3	0.0	0
Bark Hogging (wet material drop)	354,182	bdt/yr	0.00075	0.00035	0.00005		0.0	0.0	0.0	0
Yard Cleanup (wet material drop)	8,015	bdt/yr	0.00075	0.00035	0.00005		0.133	0.062	0.0089	0
					TOTAL		52.9	26.7	12.9	0.0

PM, PM_{10} and $PM_{2.5}$ EF Basis: EPA Region 10 Particulate Matter Potential to Emit Emission Factors for Activities at Sawmills, Excluding Boilers, Located in Pacific Northwest Indian Country, May 8, 2014.

Annual Capacity Basis: Initial Part 71 2005 permitting action

Abbreviations

bdt: bone dry ton

Non-HAP Potential to Emit

Emission Unit: **PT**

Description: Plant Traffic. Fugitive emissions including forklifts and log trucks (paved and unpaved roads)

FUGITIVE EMISSIONS

Potential to Emit, (tons per year)

Activity	Location	Loaded Weight (tons)	Empty Weight (tons)	Average Weight (tons)	Paved Road Emission Factors (lb/VMT)			Unpaved Road Emission Factors (lb/VMT)			Round Trip Distance Paved Roads (miles)	Round Trip Distance Unpaved Roads (miles)	Number of Trips per Year	VMT Paved Roads (miles)	VMT Unpaved Roads (miles)	Emissions (tpy)		
					PM	PM_{10}	$PM_{2.5}$	PM	PM_{10}	$PM_{2.5}$						PM	PM_{10}	$PM_{2.5}$
Log Delivery	Scale/GR Yard	40.0	13.5	26.8	73.306	14.661	3.599	13.116	4.015	0.401	0	0.560	9,277	0	5,195	34.1	10.4	1.0
Log Delivery	Gate/Yard 2	40.0	13.5	26.8	73.306	14.661	3.599	13.116	4.015	0.401	0.960	0.000	3,092	2,968	0	108.8	21.8	5.3
Log Delivery	Gate/Yard 3	40.0	13.5	26.8	73.306	14.661	3.599	13.116	4.015	0.401	1.120	0.400	0	0	0	0.0	0.0	0.0
Logs Leaving	Scale/GR Yard	40.0	13.5	26.8	73.306	14.661	3.599	13.116	4.015	0.401	0	0.560	9,277	0	5,195	34.1	10.4	1.0
LeTourneau Delivery	GR Yard	59.0	33.0	46.0	127.433	25.487	6.256	16.739	5.124	0.512	0	0.120	9,277	0	1,113	9.3	2.9	0.3
LeTourneau Delivery	GR Yard/Yard 1	59.0	33.0	46.0	127.433	25.487	6.256	16.739	5.124	0.512	0	0.480	9,277	0	4,453	37.3	11.4	1.1
LeTourneau Delivery	Yard 2	59.0	33.0	46.0	127.433	25.487	6.256	16.739	5.124	0.512	0	0.140	3,092	0	433	3.6	1.1	0.1
LeTourneau Delivery	Yard 3	59.0	33.0	46.0	127.433	25.487	6.256	16.739	5.124	0.512	0	0.140	18,555	0	2,598	21.7	6.7	0.7
LeTourneau Delivery	Yard 1/Barker	59.0	33.0	46.0	127.433	25.487	6.256	16.739	5.124	0.512	0	0.300	9,277	0	2,783	23.3	7.1	0.7
LeTourneau Delivery	Yard 2/Barker	59.0	33.0	46.0	127.433	25.487	6.256	16.739	5.124	0.512	0	1.180	3,092	0	3,649	30.5	9.3	0.9
LeTourneau Delivery	Yard 3/Barker	59.0	33.0	46.0	127.433	25.487	6.256	16.739	5.124	0.512	0	1.480	18,555	0	27,461	229.8	70.4	7.0
LeTourneau Delivery	Barker/Infeed	59.0	33.0	46.0	127.433	25.487	6.256	16.739	5.124	0.512	0	0.600	15,462	0	9,277	77.6	23.8	2.4
Front Loader - Log Handling	Barker/Infeed	30.0	15.0	22.5	61.446	12.289	3.016	12.133	3.714	0.371	0	0.600	3,092	0	1,855	11.3	3.4	0.3
Front Loader - Hog Handling	Yard/Hog	30.0	15.0	22.5	61.446	12.289	3.016	12.133	3.714	0.371	0.180	0.180	1,546	278	278	10.2	2.2	0.5
Hog Fuel Delivery	Yard/Fuel Dump	9.0	5.0	7.0	18.675	3.735	0.917	7.174	2.196	0.220	0.380	0.660	773	294	510	4.6	1.1	0.2
Chips Leaving	Gate/Bin	40.0	13.5	26.8	73.306	14.661	3.599	13.116	4.015	0.401	0.333	0	1,869	622	0	22.8	4.6	1.1
Sawdust Leaving	Gate/Bin	40.0	13.5	26.8	73.306	14.661	3.599	13.116	4.015	0.401	0.333	0	43	14	0	0.5	0.1	0.0
Shavings Leaving	Gate/Bin	40.0	13.5	26.8	73.306	14.661	3.599	13.116	4.015	0.401	1.111	0.593	1,193	1,325	707	53.2	11.1	2.5
Lumber Leaving	Gate/Station 1	40.0	13.5	26.8	73.306	14.661	3.599	13.116	4.015	0.401	0.519	0	2,184	1,133	0	41.5	8.3	2.0
Lumber Leaving	Gate/Station 2	40.0	13.5	26.8	73.306	14.661	3.599	13.116	4.015	0.401	1.037	0	2,184	2,265	0	83.0	16.6	4.1
Forklift Handle Green Lumber	Stacker/G Storage	12.0	7.0	9.5	25.500	5.100	1.252	8.231	2.520	0.252	0.111	0	31,938	3,545	0	45.2	9.0	2.2
Forklift Handle Green Lumber	G Storage/Kiln	12.0	7.0	9.5	25.500	5.100	1.252	8.231	2.520	0.252	0.148	0	10,646	1,576	0	20.1	4.0	1.0
Forklift Handle Dry Lumber	Kiln/D Storage	12.0	7.0	9.5	25.500	5.100	1.252	8.231	2.520	0.252	0.111	0	63,877	7,090	0	90.4	18.1	4.4
Forklift Handle Dry Lumber	D Storage/Planer	12.0	7.0	9.5	25.500	5.100	1.252	8.231	2.520	0.252	0.130	0	31,938	4,152	0	52.9	10.6	2.6
Forklift Handle Finish Lumber	Stacker/Packing	12.0	7.0	9.5	25.500	5.100	1.252	8.231	2.520	0.252	0.037	0	10,646	394	0	5.0	1.0	0.2
Forklift Handle Finish Lumber	Packing/Storage	12.0	7.0	9.5	25.500	5.100	1.252	8.231	2.520	0.252	0.185	0	63,877	11,817	0	150.7	30.1	7.4
Forklift Handle Finish Lumber	Storage/Truck	12.0	7.0	9.5	25.500	5.100	1.252	8.231	2.520	0.252	0.074	0	53,231	3,939	0	50.2	10.0	2.5
Vender Trucks	Yard	30.0	30.0	30.0	82.401	16.480	4.045	13.810	4.228	0.423	0.222	0	750	167	0	6.9	1.4	0.3
															TOTAL	1258.8	307.0	52.2

VMT - vehicle miles traveled

• Paved Road Emission Factors (EF_{PR}) = k x $(sL)^{0.91}$ x $(W)^{1.02}$

Source: AP-42 (01/11), Chapter 13.2.1, Equation 1.

EF_{PR} = paved road emission factor in units of pounds pollutant per vehicle mile traveled (lb/VMT)

sL = road surface silt loading in units of grams per square meter (g/m^2). This equals worst-case value of 400 g/m^2 as noted on page 13.2.1-5 of AP-42. Applicant provided no estimate.

sL: 400 g/m^2

W = average weight of vehicles traveling the road in units of tons. This is equal to value listed in spreadsheet per applicant assumption.

k = particle size multiplier for particle size range in units of lb/VMT. See AP-42 Table 13.2.1-1 as follows:

PM: 0.011 lb/VMT

PM_{10}: 0.0022 lb/VMT

$PM_{2.5}$: 0.00054 lb/VMT

• Unpaved Road Emission Factors (EF_{UPR}) = k $(s/12)^a$ x $(W/3)^b$

Source: AP-42 (11/06), Chapter 13.2.2, Equation 1a.

EF_{UPR} = unpaved road emission factor in units of pounds pollutant per vehicle mile traveled (lb/VMT)

s = surface material silt content in units of percent (%). This is equal to 12% pursuant to worst-case value appearing in Table 13.2.2-1 for log yards in lumber sawmills. Applicant provided no estimate.

s: 12 %

W = average weight of vehicles traveling the road in units of tons. This is equal to value listed in spreadsheet per applicant assumption.

k, a and b are empiracal constants. See AP-42 Table 13.2.2-2 as follows:

	k (lb/VMT)	a	b
PM	4.9	0.7	0.45
PM_{10}	1.5	0.9	0.45
$PM_{2.5}$	0.15	0.9	0.45

• Emissions (tons per year) = EF (lb/VMT) x VMT x (ton/2000 lb)

Potential to Emit

Emission Unit: **PH5**
Description: Wellons Boiler. Model Number NB234. Serial Number B2329-0503.
Two-cell pile-burning design with automatic rotating grates. Overfeed fuel delivery.
Combustion air introduced below grates and also above grates at 2 separate heights.
See combustor cell system at http://www.wellons.ca/energycombustors.html
Maximum Steam Production: 80,000 lb/hr at 250 psig and 750°F
Particulate Matter Control Device: Multiclones and electrostatic precipitator (required by this Title V permit)
Fuel: Biomass (hog fuel, wood residue or purchased forest slash)
Commence Construction: After 06/09/84 but before 02/28/05. NSPS Subpart Db and PM limit applicability.
Startup: 12/27/2005
Design Maximum Heat Input Capcity: 131 MMBtu/hr
Operation: 8760 hours per year

Potential to Emit, (tons per year)

Hazardous Air Pollutants	EF (lb/MMBtu)	PTE (tpy)
Trace Metal Compounds		
Antimony Compounds	7.90E-06	4.53E-03
Arsenic Compounds (including arsine)	2.20E-05	1.26E-02
Beryllium Compounds	1.10E-06	6.31E-04
Cadmium Compounds	4.10E-06	2.35E-03
Chromium Compounds (including hexavalent)	2.10E-05	1.20E-02
Cobalt Compounds	6.50E-06	3.73E-03
Lead Compounds (not elemental lead)	4.80E-05	2.75E-02
Manganese Compounds	1.60E-03	9.18E-01
Mercury Compounds	3.50E-06	2.01E-03
Nickel Compounds	3.30E-05	1.89E-02
Phophorus	2.70E-05	1.55E-02
Selenium Compounds	2.80E-06	1.61E-03
Other Inorganic Compounds		
Chlorine	7.90E-04	4.53E-01
Hydrochloric acid (hydrogen chloride)	2.26E-03	1.30E+00
Organic Compounds		
Acetaldehyde	8.30E-04	4.76E-01
Acetophenone	3.20E-09	1.84E-06
Acrolein	4.00E-03	2.30E+00
Benzene	4.20E-03	2.41E+00
Bis(2-ethylhexyl)phthalate (DEHP)	4.70E-08	2.70E-05
Carbon tetrachloride	4.50E-05	2.58E-02
Chlorobenzene	3.30E-05	1.89E-02
Chloroform	2.80E-05	1.61E-02
Dibenzofurans[1]	1.87E-09	1.07E-06
2,4-Dinitrophenol	1.80E-07	1.03E-04
Ethyl benzene	3.10E-05	1.78E-02
Ethylene dichloride (1,2-Dichloroethane)	2.90E-05	1.66E-02
Formaldehyde	4.40E-03	2.52E+00
Methyl bromide (Bromomethane)	1.50E-05	8.61E-03
Methyl chloride (Chloromethane)	2.30E-05	1.32E-02
Methyl chloroform (1,1,1-trichloroethane)	3.10E-05	1.78E-02
Methylene chloride (Dichloromethane)	2.90E-04	1.66E-01
Naphthalene[1]	9.70E-05	5.57E-02
4-Nitrophenol	1.10E-07	6.31E-05
Pentachlorophenol	5.10E-08	2.93E-05
Phenol	5.10E-05	2.93E-02
Polychlorinated biphenyls (PCB)	7.93E-09	4.55E-06
Polycyclic Organic Matter (POM)	1.27E-04	7.27E-02
Propionaldehyde	6.10E-05	3.50E-02
Propylene dichloride (1,2-Dichloropropane)	3.30E-05	1.89E-02
Styrene	1.90E-03	1.09E+00
2,3,7,8-Tetrachlorodibenzo-p-dioxin[1]	8.60E-12	4.93E-09
Tetrachloroethylene (tetrachloroethene)	3.80E-05	2.18E-02
Toluene	9.20E-04	5.28E-01
Trichloroethylene (Trichloroethene)	3.00E-05	1.72E-02
2,4,6-Trichlorophenol	2.20E-08	1.26E-05
Vinyl chloride	1.80E-05	1.03E-02
Xylenes (inlc isomers and mixtures)	2.50E-05	1.43E-02
TOTAL[2]	2.20E-02	12.6

[1] designates a HAP that is subject individually to the 10 tpy major source threshold, but that is also one of several polycyclic organic matter (POM) compounds that, in aggregate, are subject to the same 10 tpy major source threshold.

[2] Because dibenzofurans, naphthalene and 2,3,7,8-Tetrachlorodibenzo-p-dioxin (one of several dibenzodioxins) are accounted for individually and in the calculation of POM EF, their individual contribution here is discounted so as to avoid double-counting

EF Reference: HAP Potential to Emit Emission Factors for Biomass Boilers Located in Pacific Northwest Indian Country, EPA Region 10, May 8, 2014. Because the boiler is not subject to NESHAP DDDDD, employ default AP-42 emission factors for all pollutants except for HCl. The HCl emission factor is determined as follows:

Appendix A: Potential Emissions Inventory

PH5 HCl EF = (% wt Cl / 100) X (MW HCl / MW Cl) X (1 / HHV) X ($1x10^6$ Btu / MMBtu) X (% Cl → HCl / 100)

PH5 HCl EF = 0.00226 lb/MMBtu

Values for Parameters in Equation

% wt Cl:	0.01269	% dry, highest 12-month average concentration based on WSFPI fuel sampling and analysis conducted 2008 to 2013
MW HCl:	36.46	lb/lb-mol (constant)
MW Cl:	35.453	lb/lb-mol (constant)
High Heating Value:	8667	Btu/lb, HHV wood = (5200/(1-0.4)). See page A-5 of Appendix A to AP-42, September 1985. (HHV wood < HHV bark)
Fuel Cl → Exhaust HCl:	15	%, upper bound estimation based upon fuel sampling and stack test data for two biomass boilers in Oregon

PH5 HCl EF based upon 15% conversion of fuel chlorine to exhaust HCl. Here is a summary of the data supporting 15% value:

Source	Test Date	Fuel Type	Fuel HHV Btu/lb	Fuel Chlorine Content ppm (dry)	Fuel HCl[1] lb/mmBtu	Stack HCl[2] lb/mmBtu	Fuel Cl → Exhaust HCl[3] %
Boise Building (Elgin, OR)[4]	4/5/2012	Hog Fuel	8935	73	0.008402	0.00071	8.5
	4/5/2012	Hog Fuel	8810	69.5	0.008113	0.00032	3.9
Flakeboard (Eugene, OR)[5]	8/26/2009	Sanderdust/NG	8360	82	0.010087	0.000718	7.1

High Conversion (%): 8.5

Footnotes:

[1] HCl emission factor assuming all fuel chlorine is converted to HCl

[2] Measured HCl in boiler exhasut

[3] Percentage of fuel chlorine that is converted to HCl and is exhausted.

[4] Fuel = 65% wood, 35% bark with plytrim added

[5] Fuel = 28% sanderdust and 72% natural gas

Assumptions:

Sanderdust high heating value = 8509 Btu/lb

Ratio of 36.5/35.5 used to convert Cl to HCl

The 15% value employed to estimate the extent of the conversion of fuel chlorine to exhaust HCl is nearly twice the highest measured conversion rate of 8.5%.

PH5 HCl EF based upon highest chlorine content measured for 19 separate WSFPI sampling and analysis events conducted over 5 years. Here is a summary of the data:

Year	Month	Chlorine % by wt - wet	Moisture Content %	Average Chlorine % by wt - dry	12-month Rolling Chlorine, % by wt - dry	Document
2008	apr	0.01	44.88	0.01909		07/29/08 Six Month Monitoring Report, p 8
		0.011	43.95			
		0.011	43.59			
2009	mar	0.003	38.17	0.00542		01/29/10 Annual Compliance Report, p 52
		0.003	38.59			
		0.004	38.59			
	sep	0.008	23.07	0.00867		01/29/10 Annual Compliance Report, p 54
		0.004	24.15			
		0.008	22.65			
	Quarter 4	0.008	38.77	0.00767	0.01021	01/29/10 Annual Compliance Report, p 55
		0.003	38.97			
		0.003	40.38			
2010	mar	0.003	40.62	0.00502	0.00669	03/29/11 Emissions Report for 2010, p 26
		0.003	39.54			
		0.003	40.49			
	jun	0.013	32.68	0.01832	0.00992	03/29/11 Emissions Report for 2010, p 27
		0.013	35.33			
		0.01	35.65			
	sep	0.005	11.87	0.00570	0.00918	03/29/11 Emissions Report for 2010, p 28
		0.005	12.50			
		0.005	12.46			
	dec	0.003	41.18	0.00514	0.00855	03/29/11 Emissions Report for 2010, p 29
		0.003	42.19			
		0.003	41.69			
2011	feb	0.012	38.30	0.01285	0.01050	2011 Six Month Monitoring Report, p 22
		0.005	36.78			
		0.007	37.49			
	sep	0.008	35.47	0.01552	0.00980	2011 Six Month Monitoring Report, p 24
		0.008	31.24			
		0.016	28.97			
	dec	0.007	35.79	0.01154	0.01126	2011 Six Month Monitoring Report, p 25
		0.007	37.56			
		0.008	36.07			
2012	mar	0.005	37.75	0.01084	0.01269	NT5 Report for 2012, pg 22
		0.01	38.97			
		0.005	38.32			
	may	0.004	32.07	0.00500	0.01073	NT5 Report for 2012, pg 23
		0.003	34.88			
		0.003	33.33			
	sep	0.004	25.59	0.00558	0.00824	NT5 Report for 2012, pg 24
		0.004	33.18			
		0.004	25.52			
	Quarter 4	0.003	32.54	0.00451	0.00648	NT5 Report for 2012, pg 25
		0.003	32.85			
		0.003	34.86			
2013	mar	0.005	37.75	0.01084	0.00648	NT5 Report for 2013, pg 1
		0.01	38.97			
		0.005	38.32			
	jun	0.006	25.98	0.00614	0.00677	NT5 Report for 2013, pg 2
		0.003	34.49			
		0.004	30.35			
	Quarter 3	0.004	21.76	0.00941	0.00772	NT5 Report for 2013, pg 3
		0.004	22.39			
		0.014	22.02			
	dec	0.003	34.57	0.00813	0.00863	NT5 Report for 2013, pg 4
		0.007	35.03			
		0.006	33.63			

Highest 12-month avg % by wt - dry: 0.01269

HAP Potential to Emit

Emission Unit: **KLN-N**
Description: Lumber drying
Control Device: None
Work Practice: None
Fuel: None - indirect steam provided by Wellons Boiler
Predominant Species Dried: Douglas Fir, Hemlock, Ponderosa Pine, White Fir
Installed: 5 single-track Nardi kilns (No.'s 1 - 5) installed 1997
Annual Capacity: 76,850 mbf/yr

Potential to Emit, (tons per year)

Hazardous Air Pollutants	EF (lb/mbf)	PTE (tpy)
Methanol	0.1484	5.7
Formaldehyde	0.0034	0.1
Acetaldehyde	0.1378	5.3
Propionaldehyde	0.0018	0.1
Acrolein	0.0026	0.1
TOTAL		11.3

EF Reference: EPA Region 10 HAP and VOC Emission Factors for Lumber Drying, December 2012. Because the facility has the ability to dry resinous and non-resinous softwood species but at temperatures less than or equal to 200^{0}F as restricted by non-Title V permit No. R10NT500401, select the highest EF from among all softwood species for drying at less than or equal to 200^{0}F. See EF for drying western red cedar.

Abbreviations
mbf: 1,000 board foot lumber

HAP Potential to Emit

Emission Unit: **KLN-W**
Description: Lumber drying
Control Device: None
Work Practice: None
Fuel: None - indirect steam provided by Wellons Boiler
Predominant Species Dried: Douglas Fir, Hemlock, Ponderosa Pine, White Fir
Installed: 2 double-track Wellons kilns (No.'s 6A- 7B) installed 2000
Annual Capacity: 61,480 mbf/yr

Potential to Emit, (tons per year)

Hazardous Air Pollutants	EF (lb/mbf)	PTE (tpy)
Methanol	0.1484	4.6
Formaldehyde	0.0034	0.1
Acetaldehyde	0.1378	4.2
Propionaldehyde	0.0018	0.1
Acrolein	0.0026	0.1
TOTAL		9.0

EF Reference: EPA Region 10 HAP and VOC Emission Factors for Lumber Drying, December 2012. Because the facility has the ability to dry resinous and non-resinous softwood species but at temperatures less than or equal to 200^{0}F as restricted by non-Title V permit No. R10NT500401, select the highest EF from among all softwood species for drying at less than or equal to 200^{0}F. See EF for drying western red cedar.

Abbreviations
mbf: 1,000 board foot lumber