United States Environmental Protection Agency
Region 10, Air and Radiation Division
1200 Sixth Avenue, Suite 155, 15-H13
Seattle, Washington 98101

Permit Number: R10T5090000
Issued: DRAFT
Effective: DRAFT
Expiration: five years from issue
AFS Plant I.D. Number: 16-009-00001

Statement of Basis

Title V Air Quality Operating Permit
Initial Permit

Permit Writer: Dan Meyer

PotlatchDeltic Land and Lumber, LLC – St. Maries Complex

Coeur d'Alene Reservation
St. Maries, Idaho

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 PotlatchDeltic Land and Lumber, LLC – St. Maries Complex (referred to herein as PotlatchDeltic, the SMC, 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 comply with 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.

Appendices – Appendices are attachments to this Adobe Acrobat document. To access the attachments, you must first download this document Adobe Acrobat file from the internet. Then, open the document in Adobe Acrobat Reader.

Appendix A – St. Maries Operations PTE Emissions Inventory. Open "draft sob app a.xlsx" using Microsoft Excel.

Appendix B – Applicability of FARR, NSPS and NESHAP Requirements to St. Maries Complex. Open "draft sob app b.pdf" using Adobe Acrobat Reader.

Appendix C – EPA Calculation of NESHAP Subpart DDDDD Operating Limits Applicable to PB-1 and PB-2 for Boiler Exhaust Opacity and Oxygen Content and Boiler Steam Generating Rate based upon PB-1 and PB-2 Test Results. Open "draft sob app c.xlsx" using Microsoft Excel.

Appendix D – EPA Lesson 6 – ESP Operation and Maintenance. Open "epa lesson 6 – esp operation and maintenance.pdf" using Adobe Acrobat Reader.

Appendix E – Evaluation of PB-1 and PB-2 Test Results Open "draft sob app e.xlsx" using Microsoft Excel.

Appendix F – Derivation of PB-1 Steaming-Rate Specific ESP Field-Specific Secondary Voltage Excursion Threshold Levels. Open "draft sob app e.xlsx" using Microsoft Excel.

Appendix G – Derivation of PB-2 ESP Field-Specific Secondary Voltage Excursion Threshold Levels. Open “draft sob app g.xlsx” using Microsoft Excel.

Appendix H – EPA Calculation of NESHAP Subpart DDDD Minimum Combustion Chamber Temperature Limit for Regenerative Catalytic Oxidizer Serving Veneer Dryers Based upon Performance Testing Conducted 2008 & 2023. Open “draft sob app h.xlsx” using Microsoft Excel.

Abbreviations & Symbols

APCD	Air pollution control device
ASTM	American Society for Testing and Materials
AVC	Automatic Voltage Controller
BH	Baghouse
Btu	British thermal units
CAA	Clean Air Act [42 U.S.C. section 7401 et seq.]
CFR	Code of Federal Regulations
CI	Compression ignition
CO	Carbon monoxide
CO_2e	Carbon dioxide equivalent
CY	Cyclone
EPA	United States Environmental Protection Agency (also U.S. EPA)
ESP	Electrostatic precipitator
EU	Emission unit
FR	Federal Register
FARR	Federal Air Rules for Reservations
GHG	Greenhouse gases
HAP	Hazardous air pollutant
Hp	Horsepower
IC	Internal combustion
ID	Identification
IDEQ	Idaho Department of Environmental Quality
hr	Hour
lb	Pound
m^3	Cubic meter
µg	Microgram
MACT	Maximum achievable control technology
MC	Multiclone
mmbf	One million board feet
MMBtu	One million Btu
MSDS	Material safety data sheet
MVAC	Motor vehicle air conditioner
NAAQS	National Ambient Air Quality Standards
NSPS	New Source Performance Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_X	Nitrogen oxides
NSR	New source review
OSHA	Occupational Safety and Health Administration
PCWR	Pneumatic conveyance of wood residue
PCWP	Plywood and composite wood products
PM	Particulate matter
$PM_{2.5}$	Particulate matter less than or equal to 2.5 micrometers in aerodynamic diameter
PM_{10}	Particulate matter less than or equal to 10 micrometers in aerodynamic diameter
PSD	Prevention of significant deterioration
PTE	Potential to emit
RICE	Reciprocating Internal Combustion Engine
RM	Reference Method
SI	Spark ignition

SMC	St. Maries Complex
SMO	St. Maries Operations
SO_2	Sulfur dioxide
tpy	Tons per year
ULSD	Ultra low sulfur diesel
VOC	Volatile organic compound

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 and have been updated since from time to time.

As described in 40 CFR 71.4(b), EPA will implement and enforce a part 71 operating permitting program in Indian country when an operating permit program which meets the requirements of part 70 has not been granted approval by the Administrator. Unlike States, Indian Tribes are not required to develop operating permit programs, although 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"). EPA may delegate the authority to administer a part 71 operating permit program, in whole or in part, to an Indian Tribe as described in 40 CFR 71.4(j) and 71.10.

2. Facility Information

2.1 Location

The PotlatchDeltic Land and Lumber, LLC (PotlatchDeltic) St. Maries Complex (SMC) is located along the St. Joe River near the intersection of Railroad Avenue and Mill Road in northwest St. Maries, Idaho. The facility is within the boundaries of Benewah County and the Coeur d'Alene Indian Reservation and is in Indian country as defined in 40 CFR 71. PotlatchDeltic's Lumber Drying Division (LDD) is located approximately one and one-half miles east of SMC and outside the exterior boundary of the reservation, subject to the jurisdiction of IDEQ. See Section 2.4 of this statement of basis for discussion of the relationship between SMC and LDD.

2.2 Coeur d'Alene Reservation

The Coeur d'Alene Reservation was established by Executive Order in 1873. The reservation is considered to be Indian country, as defined in 40 CFR 71. The Tribe is organized under a constitution approved by the Bureau of Indian Affairs. The Constitution provides for a seven-member tribal council to serve as the governing body of the Tribe.

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2.3 Local Air Quality and Attainment Status

The Coeur d'Alene Indian Reservation, Benewah County and Kootenai County are located in northern Idaho. The area is designated attainment or unclassifiable with the national ambient air quality standards (NAAQS) for all criteria pollutants. An area is unclassifiable when an area cannot be classified on the basis of available information as meeting or not meeting the NAAQS for the pollutant. The area in which the SMC is located is currently designated unclassifiable/attainment for the PM2.5, ozone, CO, NO2 and SO2 standards. The area is currently designated unclassifiable for the PM10 and lead standards.

A PM2.5 ambient air quality regulatory monitoring station is located just outside the reservation in St. Maries less than one mile southeast of the facility. Ambient monitoring data indicates PM2.5 concentrations are at times near the NAAQS, even when data identified by IDEQ as attributable to exceptional events (i.e., wildfires) are excluded. To reduce PM emissions in the area, the City of St. Maries and the Idaho Department of Environmental Quality are participating in EPA's PM Advance Program[1]. The PM Advance control measures focus on increasing public awareness of local air quality and reducing emissions from residential wood heating, open burning, and paved road dust.

2.4 Facility Description

The SMC consists of a sawmill, two lumber dry kilns, planer mill and plywood mill. The LDD (AFS Plant I.D. Number 16-009-00030) is located approximately 1.5 miles from the SMC but outside the reservation within state jurisdiction. At the LDD, PotlatchDeltic operates a biomass boiler to generate steam, and that steam is used to indirectly heat kilns that dry rough green lumber. Some of the rough green lumber produced at the SMC is transported to the nearby LDD where it is kiln dried and then returned to the SMC's planer mill. Hog fuel and shavings from SMC are transported to LDD and burned in a biomass boiler.

Although the SMC and the LDD are subject to the jurisdiction of different permitting authorities, the EPA and IDEQ have recognized the SMC and LDD as a single "major source" since the 1990's. This is reflected in correspondence between IDEQ and PotlatchDeltic in the administrative record for this permitting action.[2] Consistent with recent EPA guidance for determining the scope and extent of a source under the CAA,[3] EPA is not reevaluating the prior determination that the SMC and LDD together comprise a single source under the CAA, given that the facts upon which that determination was made are unchanged. In any event, whether the LDD is considered part of the same stationary source as the SMC for CAA permitting purposes does not affect the applicability of any requirements imposed in this permit.

EPA refers to the larger "stationary source" that is comprised of the SMC and LDD as St. Maries Operations (SMO). Note that the permit supported by this statement of basis only applies to the SMC.

<u>Sawmill</u>
Logs are transported to the SMC via trucks. Wood species typically consist of hemlock, douglas fir, grand fir and western red cedar. Smaller amounts of lodgepole pine, subalpine fir, Engelmann spruce, ponderosa pine and white pine are also processed. The logs are unloaded from delivery trucks and stacked in the log yard. Sprinklers are used to keep the logs wet during storage.

Logs are transferred from the log yard to the sawmill merchandiser, where the logs are loaded onto one of two decks and "singulated." On one deck, the log is debarked with an A8 22-inch debarker and then cut to length by the #2 cut-off saw. On the other deck, log defects are removed by the #1 cut-off saw, and then the log is debarked with an A5 22-inch debarker and then cut -to-length by the #3 cut-off saw. The logs from both decks are then conveyed into the Sawmill Building. Sawdust and trim from the cut-off saws, along with bark from the debarkers, are routed to an enclosed hog crusher (MK Hog). The resultant hog fuel is conveyed by chain conveyers to the hog fuel bin (FD-5), fuel storage truck bin (FD-23) or ground storage (FD-39).

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[1] See https://www.epa.gov/advance & https://www.epa.gov/system/files/documents/2021-09/id-st-maries-2021-path-forward-.pdf
[2] See October 9, 1996 letter from IDEQ to Potlatch Corporation and the February 6, 1997 letter from the Idaho Attorney General's Office to Potlatch Corporation.
[3] November 26, 2019 EPA memorandum entitled, "Interpreting "Adjacent" for New Source Review and Title V Source Determinations in All Industries Other Than Oil and Gas." As stated on page 9, "EPA expects that it would not be appropriate or necessary for permitting authorities to revisit prior source determinations based solely on a change in an EPA policy or interpretation."

Logs entering the Sawmill Building are directed to the Chip-and-Saw (CNS) which consists of the following three machine centers: four-sided canter, quad band mill and vertical arbor gang saw. The four-sided canter removes the exterior of the log through a chipping process and produces a profiled log and chips. The quad band mill removes the sideboards of the log and produces a cant, sideboards and sawdust. The vertical arbor gang breaks the cant down into lumber and sawdust.

Sideboards from the quad band mill are conveyed to a chipper edger, which produces squared-end lumber and wood chips. The lumber from the edger and the lumber from the vertical arbor gang are conveyed to trim saws, where they are scanned for defects and trimmed. Lumber is then transferred to the bin sorter and stacked according to size in rough green lumber storage. Trim ends are sent to a chipper. Fine dust from the quad band mill, trimmer, chipping edger and vertical arbor gang is controlled by BH-10. Collected dust goes to the hog fuel storage bin.

Wood chips from CNS, chipper edger and chipper are conveyed to a screener. The screener sorts the incoming material into overs, wood chips and sawdust. Overs are sent back to the chipper. Chips are pneumatically routed to the chip bin through the Sawmill Chip Bin Cyclone (CY-2). Sawdust from the screen, quad band mill, and vertical arbor gang are pneumatically conveyed to the sawdust truck bin. Sawdust Bin Baghouse (BH-11) controls the bin exhaust.

From rough green lumber storage, the lumber is either planed green in the Planer Mill or dried in one of two lumber dry kilns located at the SMC or in one of four kilns at the LDD. Kiln LK-5 at the SMC has a capacity of 290,000 board feet per charge while the newer kiln LK-6 has a demonstrated capacity of 282,426 board feet per charge. Dry kiln operating temperature and dry time per charge is wood specie dependent. The maximum temperature of air exiting a load of lumber while drying in kiln LK-5 is approximately 245°F, but some wood species (i.e., cedar and ponderosa pine) are dried at lower temperatures. The temperature of air exiting a load of lumber in kiln LK-6 may not exceed 245°F. PotlatchDeltic dries several wood species in their lumber dry kilns, but predominant wood species product groupings are hemfir and douglas fir/larch. Smaller quantities of Engelmann spruce/lodgepole pine and cedar are dried in the lumber dry kilns, and very small quantities of ponderosa pine are dried at the SMC. PotlatchDeltic is prohibited from drying any species other than grand fir, white fir and western hemlock in kiln LK-6.

<u>Planer Mill</u>
As lumber enters the planer mill, a break down hoist "singulates" and transfers the lumber to the pineapple rollers, which feed the rough lumber into the planer. Planer shavings are pneumatically conveyed to the planer shavings bin via cyclone CY-10. Planer Shavings Baghouse (BH-2) receives CY-10 exhaust, and collected dust is transferred to the planer shavings bin. Baghouse 5 and 12 (BH-5 & 12) control the exhaust from the planer shavings bin. The surfaced lumber is graded and trimmed to length. A sorter is used to separate planed lumber by grade and length. The sorted lumber is then stacked, banded and wrapped with paper. Finished units are transferred to surfaced lumber storage until shipment off-site.

Trim ends are sent to a chipper or stored for finger joints. Dust pickups from the breakdown hoist, pineapple rolls, trimmer and chipper are controlled by the Trimmer/Chipper Baghouse (BH-3). Collected dust goes to the planer shavings bin. Chips from the chipper are pneumatically conveyed to the plytrim bin. The Plytrim Truck Bin Baghouse (BH-4) controls the ply trim bin exhaust.

Dust generated by the load out of planer shavings into trucks is captured and pneumatically conveyed to BH-5. Collected dust drops into planer shavings bin.

<u>Plywood Mill</u>
Logs are transferred from the log yard to the plywood mill merchandiser, where the logs are loaded onto one deck and "singulated." On the deck, the log passes through a 35-inch debarker and is then cut into sheathing block lengths by a 40-inch cut-off saw. Bark, wood block trim ends and sawdust are conveyed

to a hog (Lamb Hog) for sizing and then transferred to the fuel storage bin or ground storage. The blocks are sorted into bins and moved to the block conditioning vaults, where hot water is introduced and the blocks are heated until their internal temperature reaches specifications. After the blocks have been conditioned, they are removed from the vaults and transferred to a step feeder.

The conditioned blocks are transferred from the step feeder to the veneer lathe and peeled into veneer. The clipper cuts the green veneer into sheets or strips, and the veneer sheets and strips are stacked and stored before drying. Rejected blocks are sold as short logs or sent to a contract chipper. Cores from the veneer lathe are either sold or transferred to the core chipper. Rejected veneer is transferred to the veneer chipper. Chipped cores, chipped veneer and fines from the veneer clipper are transferred to a screener. Overs from the screener are sent to a chipper and then transferred to the plywood north and south chip truck bins. Correctly-sized material is transferred to the fuel storage bin or ground storage. Fines are pneumatically transferred to the fuel storage bin FD-5 or the sawdust truck bin. Sawdust Bin Baghouse (BH-11) controls the sawdust in the exhaust.

Green veneer is transferred to one of four steam-heated veneer dryers. Waste veneer collected at the veneer infeed is transferred to the veneer chipper. Exhaust from the heated sections of the veneer dryers is routed to a regenerative catalytic oxidizer (RCO) control system before venting to the atmosphere. The cooling section of the veneer dryers is vented directly to the atmosphere via roof vents. Veneer dryer exhaust can bypass the RCO.

Veneer is monitored for moisture content at the out-feed from each veneer dryer. If the moisture content is too high, veneer is separated and stored before transferring the veneer back to a dryer inlet for redrying. Veneer Dryer #3 is equipped with a refeeding system, including a strip stacker that holds nearly dry veneer until target moisture content is achieved.

Dry veneer is graded, sorted (manually or through the Metra-Guard) and handled by the automated dry veneer stacker. The graded dry veneer can be transferred to storage or one of the following processing lines: Raimann Patch Line, core composers or auto layup line. The Raimann Patch Line upgrades veneer by replacing defects with plugs of clear face veneer. A strip machine is used to make the veneer patches for the Raimann Line. The core composers make the inner section of plywood by clipping and gluing veneer sheets with hot melt and string. The auto layup line sandwiches veneer and glue layers according to product specifications.

From storage, dry veneer can be transferred to any of the processing lines described above.

Assembled plywood panels are conveyed to the pre-press area, where the panels are cold pressed. The panels are then transferred into one of two hot presses. Product specifications determine the pressure cycles applied to the panels. A building vent to atmosphere is located above each hot press.

Panels leaving the hot presses are transferred to storage, the patch line or the trim saw line. The patch line removes defects from the panel and repairs the area with a synthetic patch. The trim saw line squares and grades the plywood panel. After the synthetic patch line and the trim saw line, panels are transferred to either auto stencil and branding or the Kimwood Sander. Finished panels go to auto stencil and banding before transferring to on-site storage and shipping. The Kimwood Sander sands and grades the panel. Panels leaving the Kimwood Sander can be transferred to the following: storage and shipping as finished products, touch sanding/T&G line, oil and edge-seal line, scarf line or synthetic patch line. At the touch sanding/T&G line, panels are sanded and/or have tongue and groove connections cut into the panel. At the oil and edge-seal line, panels are treated for concrete casting requirements. At the scarf line, two plywood panels are joined using beveled edges, glue and pressure to create a longer plywood panel. At the synthetic patch line, defects are removed.

Dry veneer waste from dryer out-feed, core composers, lay-up line, synthetic patch lines and trim saw line is transferred to the dry veneer chipper. Chips are transferred to the intermediate storage bin through the

Plytrim Cyclone (CY-4) and then transferred to either the plytrim bin or the fuel storage bin. Dust pickups from the dry veneer stacker, core composers 1, 2 and 3, pre-press bandsaws 1 and 2, synthetic patch lines, the trim saw line and air from CY-4 are all routed to the Plytrim Baghouse (BH-9). Fines collected by BH-9 are directed to the intermediate storage bin.

Dust and fines from the Kimwood Sander are transferred to the Sander Cyclone (CY-3). Sander Cyclone exhaust is controlled by BH-6. Dust collected by BH-6 goes to cyclone CY-7 or CY-8. Baghouse BH-7 controls the exhaust from CY-7 and the exhaust from truck bin vent. Dust collected by BH-7 goes to the truck bin. Dust and fines from the Raimann line, the touch sander/T&G line, the scarf line, and the strip machine are transferred to the Sander Dust Burner Surge Bin through CY-8. The Sander Dust Burner Baghouse (BH-8) controls the exhaust from CY-8. The dust collected by the baghouse is recirculated back to CY-8.

Steam Generating Plant

PotlatchDeltic operates two biomass boilers at the SMC to provide steam for block conditioning vaults, veneer dryers, plywood presses, the lumber dry kiln and building heat. Heat for the CE boiler (PB-1) is provided by two Wellons fuel cells, which are controlled by a multiclone and a two-cell PPC dry electrostatic precipitator (ESP). The CE boiler’s demonstrated heat input capacity is 58 mmbtu/hr and produces up to 43,034 pounds of steam per hour. The Riley boiler (PB-2) is controlled by a multiclone and a three-cell PPC dry ESP. The Riley boiler’s demonstrated heat input capacity is 131 mmbtu/hr and produces up to 98,000 pounds of steam per hour. The Riley boiler is also capable of burning sander dust generated from dry-end plywood operations. Fly ash from both the CE and Riley boilers is re-injected into the Riley boiler.

Emergency Engines

PotlatchDeltic operates two diesel CI fire water pumps and nine propane-fired SI emergency generators at the SMC.

2.5 Identification of Emission Generating Activities

The air pollution emission units and control devices at the SMC are listed in Tables 2-1 and 2-2 below by emission unit identification (EU ID) and categorized as either generating fugitive or non-fugitive emissions.[4] Installation dates (if known) 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: Non-fugitive Emission Units & Air Pollution Control Devices

EU ID	Emission Unit Description	Air Pollution Control Device
EU-1	PB-1: CE Boiler. Biomass boiler manufactured by Combustion Engineering Company, Inc. Model: EC2-S-CI-VESSEL. Serial number: 8045. Furnace is comprised of two fuel cells. 43,034 lb/hr maximum daily average steam generating rate observed 2016-2017. This equates to 58 mmBtu/hr using FHISOR of 1.342 mmBtu/mlb steam	Multiclone MC-1 installed March 1979, is followed by a two-field dry ESP DESP-1 manufactured by PPC Industries, Model S-1212 installed April 12, 1995.

[4] Emision generating activities collectively identified as a single emission unit in Tables 2-1 and 2-2 may not necessarily constitute a single emission unit outside of the title V permit program. For instance, Region 10 has chosen to identify PB-1 and PB-2 together as emission unit EU-1 in this title V permit as permissible pursuant to the definition of *emissions unit* in 40 CFR 71.2. The boilers, however, are separate emission units for purposes of the NSR permit program. Undertaking a modification (physical or operational change) to one boiler does not constitute a modification to the other.

EU ID	Emission Unit Description	Air Pollution Control Device
	measured during February 24, 2016 NESHAP DDDDD testing at a steam generating rate of 34,211 lb/hr. Furnace combusts wet biomass (greater than 20% moisture content, wet basis) comprised of SMC wood residuals. Dry biomass combusted during startup. Fly ash collected and screened, but not reinjected into PB-1. Boiler installed July 1964. In 1979, dutch oven firebox replaced with fuel cells.	
	PB-2: Riley Boiler. Biomass boiler manufactured by Riley Power, Inc. Serial number: 23433. Spreader stoker. 98,000 lb/hr maximum daily average steam generating rate observed 2016-2017. This equates to 131 mmBtu/hr using FHISOR of 1.335 mmBtu/mlb steam measured during February 23, 2016 NESHAP DDDDD testing at a steam generating rate of 90,101 lb/hr. Furnace combusts wet biomass (greater than 20% moisture content, wet basis) comprised of SMC wood residuals. Dry biomass combusted during startup. Fly ash collected from PB-1 and PB-2 reinjected into PB-2 after screening out inorganics. Boiler installed 1966.	Multiclone MC-2 installed October 1987 is followed by a three-field dry ESP DESP-2 manufactured by PPC Industries, Model 11R-1328-3712S installed June 24, 1995.
EU-2	VD-1, VD-2, VD-3 and VD-4: veneer dryers No. 1 through 4. Each dryer has a heating section, cooling section and experiences leaks. Pacific Northwest softwood is processed at about 380°F. Depending on the wood species and veneer thickness, the residence time in a dryer varies from 4 to 25 minutes. VD-1: manual feed longitudinal dryer processing green strips and re-dry veneer. Moore dryer constructed in February 1964 with two heating sections. Production rate of 7.5 msf (3/8")/hr observed September 2008 during PCWP MACT testing. VD-2: manual feed longitudinal dryer processing veneer strips. Moore dryer constructed in February 1964 with four heating sections. Production rate of 7.2 msf (3/8")/hr observed September 2008 during PCWP MACT testing. VD-3: continuous feed Prentice dryer processing full sheets. E.V. Preutire dryer constructed in July 1967 with one heating section. Production rate of 16.2 msf (3/8")/hr observed September 2008 during PCWP MACT testing. VD-4: continuous feed longitudinal dryer processing full sheets. Moore dryer constructed in September 1980 with four heating sections. Production rate of 15.8 msf (3/8")/hr observed September 2008 during PCWP MACT testing.	Heating Section: Two-chamber regenerative catalytic oxidizer (RCO) manufactured July 2008 by Geoenergy. The GeoCat RCO uses two 4 MMBtu/hr Maxon Kinemax propane burners.
	VDHS-1, VDHS-2, VDHS-3 and VDHS-4: heating sections of veneer dryers no.'s 1 through 4. Green softwood veneer sheets are dried. Re-drying is also	RCO

EU ID	Emission Unit Description	Air Pollution Control Device
	accomplished. Emissions are collected and pulled by a variable speed drive ID fan to a two-can RCO rated at 82,204 acfm. Each dryer is equipped with its own bypass stacks for those instances when collected emissions are diverted to atmosphere.	
	VDL-1, VDL-2, VDL-3 and VDL-4: leaks from veneer dryers no.'s 1 through 4. Leaks from doors and as veneer enters and exits dryers. Emissions exhaust to atmosphere without assistance of a fan through a vent along the length of the dryer in the roof of the building.	None
	VDCS-1, VDCS-2, VDCS-3 and VDCS-4: cooling sections of veneer dryers no.'s 1 through 4. Cool air is swept across the veneer sheets exiting the heating section. After cooling the veneer, the air is vented to atmosphere via a stack.	None
EU-3	PCWP MACT Group 1 miscellaneous coating operations.	
	ES: applying non-HAP surface coating to edges of plywood panels. Activity occurs at the Oil and Edge Seal Line within the Specialty Machine Center.	None
	PW: applying non-HAP wood putty to plywood panel defects.	
	SCL: applying non-HAP surface coating logos to plywood panels.	
EU-4	IC-1 and IC-2: internal combustion engines no.'s 1 and 2. Each six-cylinder four-stroke ULSD-fired compression ignition engine supplies mechanical work to water pump for fire suppression in the event facility loses electricity in an emergency. Engine displacement of each is 9.0 liters. IC-1 constructed 2019 and pumps water out of the mill's surge pond, and IC-2 constructed 2019 and pumps water out of St. Joe River. Each engine has a power output rating of 327 hp.	None
EU-5	IC-3, IC-4, IC-5, IC-6, IC-7, IC-8, IC-9, IC-10 and IC-11: internal combustion engines no.'s 3 thru 11. Each nonhandheld four-stroke spark ignition propane-fired generator set supplies electricity in the event facility loses grid-supplied electricity in an emergency. IC-4 and IC-5 are lean burn engines while the rest are rich burn engines. Engine displacement of each is greater than or equal to 225 cm^3. IC-3, IC-7, IC-8, IC-10 and IC-11 are certified by the manufacturer to EPA Phase 3, Class II nonhandheld nonroad engine emission standards for propane fuel in 40 CFR 1054. Engines IC-6 and IC-9 are certified by the manufacturer to EPA Phase 1, Class II nonroad engine emission standards for propane fuel in 40 CFR 1054,	None

<table>
<tr><th>EU ID</th><th>Emission Unit Description</th><th>Air Pollution Control Device</th></tr>
<tr><td></td><td>appendix I. IC-4 and IC-5 are certified by the manufacturer to the standards applicable to emergency engines in Table 1 to 40 CFR 60, Subpart JJJJ.
<table>
<tr><th>Engine</th><th>Engine Power Output Rating (horsepower)</th><th>Year Installed</th></tr>
<tr><td>IC-3</td><td>23</td><td>2015</td></tr>
<tr><td>IC-4</td><td>40</td><td>2022</td></tr>
<tr><td>IC-5</td><td>40</td><td>2022</td></tr>
<tr><td>IC-6</td><td>31</td><td>2018</td></tr>
<tr><td>IC-7</td><td>23</td><td>2013</td></tr>
<tr><td>IC-8</td><td>23</td><td>2015</td></tr>
<tr><td>IC-9</td><td>34</td><td>2017</td></tr>
<tr><td>IC-10</td><td>13</td><td>2013</td></tr>
<tr><td>IC-11</td><td>21</td><td>2018</td></tr>
</table></td><td></td></tr>
<tr><td>EU-6</td><td>LK-5: lumber kiln no. 5. Indirect steam-heated dual-track lumber drying kiln manufactured by Wellons. Model number: DT104-HPW. Annual capacity of 158 million board feet (mmbf). Predominant wood species dried are hemfir and douglas fir/larch. Smaller quantities of Engelmann spruce/lodgepole pine and cedar are dried, and very small quantities of ponderosa pine. Kiln constructed February 2006.
LK-6: lumber dry kiln no. 6. Indirect steam-heated dual-track lumber drying kiln manufactured by Wellons. Capacity of 282,426 board foot of lumber per charge. Only White fir, grand fir and western hemlock are dried in this kiln. Operation began October 2019.</td><td>None</td></tr>
<tr><td rowspan="2">EU-7</td><td>Pneumatic Conveyance and Dust Capture Systems. Sawmill, planer mill and plywood mill dust capture systems and pneumatic conveyance systems associated with the following emission generating activities:</td><td>See specific descriptions below.</td></tr>
<tr><td>PCWR-PM-SH: Pneumatic conveyance of planer shavings from the planer to planer shavings bin via cyclone CY-10 installed circa 2020.</td><td>Baghouse BH-2. Donaldson/Torit 276-RF10 controlling cyclone exhaust installed 1996. Collected dust is transferred to the planer shavings bin.</td></tr>
</table>

EU ID	Emission Unit Description	Air Pollution Control Device
	PCWR-PM-SD: Dust capture from planed lumber trimmer, trim ends chipper, breakdown hoist and infeed rolls.	Baghouse BH-3. Donaldson/Torit 276-RF10; with cyclone precleaner design, installed 1996. Collected dust is transferred to the planer shavings bin.
	PCWR-PWM-PTB: Pneumatic conveyance of Plywood Mill dry veneer chips and fines to ply trim bin.	Baghouse BH-4. PM Hagel R9 installed 1997. Collected dust drops into the ply trim bin.
	PCWR-PM-PTB: Pneumatic conveyance of Planer Mill trim ends chips to ply trim bin.	
	PCWR-PM-PSB: Transfer of planer trimmer shavings from BH-3 (receiving material from planer trimmer) to planer shavings bin.	Baghouse BH-5 and baghouse BH-12. Collected dust drops into planer shavings bin. Baghouse BH-5: Clarke Industrial installed 2022. Baghouse BH-12: Clarke Industrial 25-1.5M installed 2020.
	PCWR-PM-PSB: Transfer of collected dust from baghouse BH-2 to planer shavings bin.	
	PCWR-PM-PSB: Transfer of collected shavings from cyclone CY-10 to planer shavings bin.	
	PCWR-PM-TBLO: Dust capture from truck bin load out of planer shavings.	Baghouse BH-5. Collected dust drops into planer shavings bin.
	PCWR-SM-SD: Dust capture from vertical arbor gang, vertical arbor gang trimmer, quad band mill and edger.	Baghouse BH-10. Clarke PAF95-20 with cyclone pre-cleaner design, installed 2008. Collected dust is transferred to the hog fuel storage bin.
	PCWR-SM-SDB: Pneumatic conveyance of sawdust from vertical arbor gang and hog fuel screen to sawdust bin.	Baghouse BH-11. Hagel installed 2001. Collected dust drops into the sawdust bin.
	PCWR-SM-CH: Pneumatic conveyance of green chips from sawmill chipper screen to chip bin via cyclone CY-2.	None
	PCWR-PWM-H: Pneumatic conveyance of green wood residue to hopper via veneer dryer no. 3 in-feed cyclone CY-5.	None
	PCMR-FR-MDF: Pneumatic conveyance of metal dust and filings from filing room to cyclone CY-9.	None
	PCWR-CS-SD: Pneumatic conveyance carpenter shop dust from shop to cyclone CY-11.	Baghouse BH-1.

EU ID	Emission Unit Description	Air Pollution Control Device
	PCWR-PWM-SDD: Pneumatic conveyance of sanderdust from Kimwood sander to CY-3.	Baghouse BH-6. MAC Environmental 144-CF-361 installed 1996. Dust collected in BH-6 is pneumatically conveyed to the truck bin via CY-7 or surge bin via CY-8.
	PCWR-PWM-TB: Pneumatic conveyance of sanderdust from CY-3 to the truck bin via CY-7.	Baghouse BH-7. Collected dust drops into the truck bin.
	PCWR-PWM-SB: Pneumatic conveyance of sanderdust from CY-3 to the surge bin via CY-8.	Baghouse BH-8. MAC Environmental 144-CF-361 installed 1970. Collected dust is pneumatically conveyed to CY-8.
	PCWR-PWM-SB: Pneumatic conveyance of fines and dust from the raimann patchline waste veneer hog to the surge bin via CY-8.	
	PCWR-PWM-SB: Pneumatic conveyance of fines and dust from the specialty machine center to the surge bin via CY-8.	
	PCWR-PWM-ISB: Pneumatic conveyance of chips from dry veneer chipper to intermediate storage bin via CY-4.	Baghouse BH-9. MAC Environmental 144-CF-361 installed 1998. Collected dust drops into the intermediate storage bin.
	PCWR-PWM-ISB: Dust capture from the synthetic patching lines and trim saw line.	
	PCWR-PWM-ISB: Sawdust and dust capture from dry veneer stacker, composer saws and pre-press saws.	
EU-8	PV-1 and PV-2: heated plywood presses no.'s 1 and 2. The presses make plywood from 0.25 to 1.125 inches in thickness. Pre-pressed veneer sheets glued together with phenol-formaldehyde resin are hot-pressed. Depending on the plywood thickness, the press cycle lasts from 2 to 13 minutes, and the steam heated press is maintained at about 320°F to promote curing of the glue. Plywood Press No. 1 holds 32 panels, was constructed in February 1964 and has a design capacity of 20 msf (3/8")/hr. Plywood Press No. 2 holds 40 panels, was constructed in February 1974 and has a design capacity of 20 msf (3/8")/hr. Emissions exhaust to atmosphere without assistance of a fan through vents in the roof of the building in the vicinity of the presses.	None
EU-9	PT: plant traffic. Also identified as FD-1. Both paved and unpaved areas.	For PT related to lumber manufacturing: Paved areas: sweeping and watering. Unpaved areas: watering and 15 mph speed

EU ID	Emission Unit Description	Air Pollution Control Device
EU-10	Miscellaneous non-fugitive activities as follows:	
	CA: Compressed air drying agent system.	None
	BV-1 through 4: building vents exhaust emissions from miscellaneous indoor activities within four buildings.	
	LS-1: Log steaming vault.	
	PP: Two plywood panel synthetic patch lines	
	Resin, lube oil and fuel tanks	
EU-11	Miscellaneous fugitive activities as follows:	
	COS: Log bucking (three cut-off saws).	None
	DB: Log debarking (two 22-inch debarkers A-8 and A5).	
	HFP: Wind erosion of outdoor hog fuel pile.	
	MTDP: Material transfer drops onto outdoor piles.	
	WRD-SH, CH, SD, HF: Wood residue drops of various types of wood residue into trucks and/or fuel bin.	

Table 2-2: Fugitive Emission Units & Air Pollution Control Practices

EU-ID	Description	Air Pollution Control Practices
Roadways, Log Yard & Hog Fuel Storage		
FD-1	Paved Roads	Applying water and sweeping
FD-1	Unpaved Roads and Log Yard	Applying water, chemical soil stabilizer or chemical dust suppressant
FD-3	Log Yard Debris Storage Pile	None
FD-4	Log Yard Recycle Pile	None
FD-39	Hog Fuel Pile	Sheltering from wind by locating pile between log decks and main production building
Sawmill & Planer Mill		
FD-6	No. 1 Cutoff Saw	None
FD-7	No. 2 Cutoff Saw	None
FD-8	No. 3 Cutoff Saw	None
FD-77	MK Hog	Water spray while processing cedar
FD-81	Merchandizing Conveyors	None
FD-82	Planer Trim Chipper	None
FD-91	A8 22” Debarker	Partial enclosure
FD-92	A5 22” Debarker	Partial enclosure
Plywood Mill		
FD-9	40” Cutoff Saw	None
FD-45	40” Debarker	Partial enclosure
FD-79	Lamb Hog	None

EU-ID	Description	Air Pollution Control Practices
Steam Generating Plant		
FD-36	Boiler Ash Houses	Partial enclosure, applying water

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 two tons per year of any regulated air pollutant excluding HAPs [40 CFR 71.5(c)(11)(ii)(A)] and less than 1,000 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)]. The emission units listed in Table 2-3 below have been identified by PotlatchDeltic as IEUs on the basis that each unit's potential to emit (PTE) for any individual regulated air pollutant (excluding HAPs) does not exceed two tons per year.

Table 2-3: Insignificant Emission Units

Number of Units	Emission Unit Description
1	BH-1 (Carpenter Shop Baghouse)
1	BH-5 (Planer Shaving Truck Bin Baghouse)
1	BH-7 (Sander Dust Truck Bin Baghouse)
1	BV-2 (Sawmill Building Vents)
1	BV-3 (Boilerhouse Building Vents)
1	BV-4 (Planer Building Vents)
2	IC-1 & IC-2 (Diesel Firewater Pump Engines)
8	IC-3 – IC-11 (Propane Emergency Generators)
5	Diesel Storage Tanks
1	Gasoline Storage Tanks
3	Propane Storage Tanks
4	Caustic and Phenolic Resin Tanks
1	Hydraulic Oil Tanks
1	Lube Oil Tanks
1	Parts Washing

2.6 Permitting, Construction and Compliance History

PotlatchDeltic submitted a timely initial Part 71 air operating permit application to EPA for SMC on October 6, 1999; and PotlatchDeltic submitted multiple application updates to EPA between 2000 and 2011. In response to requests for additional information in late 2014, PotlatchDeltic submitted a new application on March 25, 2015 to wholly replace all previously submitted materials. PotlatchDeltic has subsequently provided EPA with additional information upon request. The application has been administratively deemed complete. EPA provided PotlatchDeltic several pre-draft versions of the permit and statement of basis and considered PotlatchDeltic's verbal and written comments on these pre-drafts prior to issuing the permit for public comment.

The plywood mill was originally built in 1963, and PotlatchDeltic purchased it in 1964. The mill was converted from a traditional half-inch three-ply CDX sheathing mill to a sanded specialty operation in 1997. The sawmill was built in 1974, and the planer was added in 1983. In 1993, PotlatchDeltic purchased the lumber drying operations at what is now referred to as LDD. The planer was rebuilt in 1997. PotlatchDeltic has undertaken a number of changes at the mill as chronicled in its Title V application updates submitted to EPA over the years. For example, PotlatchDeltic installed the Metra-Guard dry veneer sorter at the plywood mill circa 2003. Around 2005, the sawmill's A8 22" debarker was installed and vertical single arbor edger replaced. Also circa 2005, the lathe charger was installed at the plywood mill. Lumber Kiln No. 5 was installed in February 2006, and the Oil and Edge Seal Line was relocated from LDD to SMC in June 2006. Circa 2007, PotlatchDeltic completed a project enabling the Riley Boiler to combust sanderdust generated by the plywood mill. Circa 2011, the plywood mill's Scarf Line was added. Lumber Kiln No. 6 began operating in October 2019 after EPA issued PSD and minor NSR permits in June 2019 authorizing its construction.

Region 10, or the Coeur d'Alene Tribe on EPA's behalf, have inspected SMC several times for compliance with CAA requirements. Records indicate that CAA inspections of the mill have been conducted approximately every other year beginning around 2003. In August 2022, EPA and PotlatchDeltic entered into a Consent Agreement and Final Order, resolving EPA claims that PotlatchDeltic failed to timely perform testing for the CE Boiler under the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial and Institutional Boilers and Process Heaters at Major Sources, 40 CFR part 63, subpart DDDDD.

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, the Permittee 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.

$$E = EF \times OP \times K$$

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 lb for conversion from pounds per year to tons per year

3.2 Potential to Emit (PTE)

As part of its Title V permit application for the SMC, PotlatchDeltic submitted detailed emission calculations for all emission units at the larger "stationary source" referred to as SMO. As discussed above in Section 2.4, the SMO consists of emission generating activities at both SMC and LDD, and program applicability is determined based upon SMC and LDD emissions combined. Appendix C of the application lists both actual and potential SMO emissions. EPA reviewed those annual emission inventories, and EPA has documented PTE in Appendix A to this statement of basis. In some instances, EPA revised the emission estimates provided by the Permittee to more accurately reflect the best estimate of potential emissions from the source. A summary of SMO's PTE is presented in Table 3-1 below. Note that fugitive emissions are not included for non-HAP pollutants, because for sawmills and plywood mills, fugitive emissions are not considered to determine program applicability as explained in more detail in Section 4.1 of this statement of basis. For HAPs, both fugitive and non-fugitive emissions are considered in determining applicability for MACT purposes.

Table 3-1: SMO's Potential to Emit (tpy)[1]

Pollutant	LDD	SMC	Total
CO	249	949	1,198
NO_X	40	172	212
PM	9	230	239
PM10	15	208	224
PM2.5	15	155	170
SO_2	2	8	10
VOC	276	443	719
GHG (CO_2e)[2]	41,831	178,017	219,848
Methanol	29	76	105
Acetaldehyde	5	19	25
Hydrogen chloride	4	18	23
Total HAP	43	139	182

[1] Fugitive emissions are not included in this table (except for HAPs) because fugitives are not used in applicability determinations for this source type (see Section 4.1). For fugitive emission estimates, see Appendix A.
[2] GHG emissions are not considered in determining Title V applicability. Calculations of GHG emissions are presented in this document for informational purposes only.

Table 3-2 below illustrates the contribution of certain SMC emission generating activities toward SMO PTE reported in Table 3-1. As stated previously for HAP, both fugitive and non-fugitive emissions are considered. For non-HAP pollutants, only non-fugitive emissions are considered.

Table 3-2: SMC's Potential to Emit (tpy)[1]

Pollutants	Emission Units							Total
	EU-1	EU-2	EU-3	EU-6	EU-7	EU-8	Other	
CO	936	1					12	949
NO_X	171	1					1	172

Pollutants	Emission Units							Total
	EU-1	EU-2	EU-3	EU-6	EU-7	EU-8	Other	
PM	26	9		3.2	167	21	4	230
PM10	6	18		7	139	36	4	208
PM2.5	6	18		7	86	36	4	155
SO_2	8	1						8
VOC	6	25	21	172	159	18	41	443
GHG (CO_2e)	173,090	4,876					50	178,017
Methanol (highest-emitting HAP)		4		54	8	10	1	76
Total HAP	33	20		63	10	11	2	139

[1] Fugitive emissions are not included in this table (except for HAPs) because fugitives are not used in applicability determinations for this source type (see Section 4.1). For fugitive emission estimates, see Appendix A.
[2] GHG emissions are not considered in determining Title V applicability. Calculations of GHG emissions are presented in this document for informational purposes only.

PotlatchDeltic is expected to use the emission factors and calculation methods presented in Appendix A unless PotlatchDeltic demonstrates that another emission factor or calculation method is appropriate (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 PotlatchDeltic 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.

3.3 Actual Emissions

PotlatchDeltic is required to pay fees annually based on an inventory of its actual emissions for the preceding calendar year (see Permit Conditions 3.41 through 3.45). Table 3-3 summarizes PotlatchDeltic's reported actual emissions generated in calendar year 2022. Unlike Tables 3-1 and 3-2 above, Table 3-3 includes fugitive PM10 emissions.

Table 3-3: SMC's Actual Emissions (tons) for Calendar Year 2022

Pollutants	Emission Units							Total
	EU-1	EU-2	EU-3	EU-6	EU-7	EU-8	Other	
NO_X	97.7	0.2					0.6	98.5
PM10	3.6	2.2		2.4	24.8	13.3	12.6	58.9
SO_2	10.6						0	10.6
VOC	8.0	8.3	0.2	74.8	24.3	6.4	5.4	127.4
Methanol highest-emitting HAP)		1.1		19.8	2.2	2.8	0.6	26.5
Total HAP	7.1	2.8		23.7	2.8	2.9	1.0	40.3

4. Regulatory Analysis

The 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 SMC is subject to federal air quality regulations, and is not subject to state air quality regulations. The Tribe has not requested or received EPA approval of air quality regulations as a "Tribal Implementation Plan" under the CAA. Therefore, Tribal air quality regulations, if any, do not meet the definition of “applicable requirement” under part 71 and are not included in the SMC Title V permit.

The EPA relied on information provided in PotlatchDeltic’s Title V permit application to determine the requirements that are applicable to the SMC. Future modifications to the facility 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 specified non-major sources) of air pollution to obtain operating permits and provide the legal bases for this permit. As discussed above in Section 2.4, the EPA and IDEQ have recognized SMC and LDD as a single “major source” since the 1990s, even though they are subject to the jurisdiction of different permitting authorities.

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 HAP (totaled) or 10 tons per year or more of any single HAP (see 40 CFR 71.2). The SMC is a major source subject to Title V because SMO (SMC and LDD, combined) has the potential to emit more than 100 tons per year of CO, NO_X, PM10, PM2.5 and VOC not counting fugitive emissions, more than 10 tons each of the HAPs hydrogen chloride, acetaldehyde and methanol, and more than 25 tons of all HAP combined.[5] See Appendix A to this statement of basis for supporting calculations. Although PM potential emissions also exceed 100 tons per year, the EPA does not consider PM a regulated pollutant for Title V applicability purposes.[6]

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 with all applicable requirements. Therefore, source-specific testing, monitoring, recordkeeping and reporting have been added where the underlying requirement does not include such requirements or where the permitting authority has determined that additional source-specific testing, monitoring, recordkeeping and reporting is necessary for a particular source to assure compliance with the underlying applicable requirement, as is the case here, as explained in Section 4.3 (Permit Conditions) of this statement of basis below.

New Source Review. The New Source Review (NSR) program requires stationary source owners or operators to obtain a permit before they begin construction of a new source or a modification to an existing source. In other words, facilities are required to obtain NSR permits for the construction of entirely new facilities and for construction projects at existing facilities such as expansions, additions, process changes, and equipment modifications. By requiring sources to meet pre-construction permitting requirements, the NSR program provides a mechanism to improve the air quality in nonattainment areas and to maintain the air quality in attainment areas.

There are three types of NSR permitting programs, each with a different set of requirements. A facility may be required to meet one or more of these sets of permitting requirements when the facility undertakes a modification. The Prevention of Significant Deterioration (PSD) program applies to the construction of a new major source or a major source making a major modification that is located in an attainment area. The PSD program generally applies to facilities that have the potential to emit 250 tons per year (tpy) or 100 tpy or more of any regulated NSR pollutant. The thresholds depend on the type of source and there is a list of 28 source categories for which the 100 tpy threshold applies. The Nonattainment NSR (NA NSR) program applies to the construction of a new major source or a major source making a major modification that is located in a nonattainment area. Generally, the NA NSR program applies to facilities that have the potential to emit 100 tpy or more of a NAAQS pollutant. However, this threshold may be lower

[5] The SMC alone would qualify as a major source considering each of the nine pollutants noted above.
[6] October 16, 1995 EPA memorandum entitled, “Definition of Regulated Pollutants for Particulate Matter for Purposes of Title V”

depending on the nonattainment severity of the area where the source is or will locate. The Minor NSR program applies to a new minor source and/or a minor modification at both major and minor sources, in both attainment and nonattainment areas. Minor NSR applies for those regulated NSR pollutants that are emitted at or above the minor NSR thresholds specified in the Tribal minor NSR rule (Table 1 to 40 CFR 49.153) but below the major source thresholds.

Because the area in which SMC is located is not classified non-attainment for any pollutant, the NA NSR program is not currently relevant. Based upon our knowledge of the facility and understanding of its potential emissions, SMC is a PSD major source considering SMO's potential to emit CO and VOC, and even when considering only the PTE of the SMC. A modification to an existing major source for a particular pollutant is subject to PSD review for each such pollutant with an emissions increase greater than defined PSD significance level for that pollutant. A modification to an existing major source for a particular pollutant is subject to minor NSR for each such pollutant with an emissions increase greater than the defined minor NSR significance level but less than the defined PSD significance level. Whereas the minor NSR program became effective August 30, 2011, the PSD program first became effective in the late 1970's. In its Title V application updates submitted to EPA over the years through March 2015, PotlatchDeltic has chronicled a number of construction projects it has completed at SMC through that date. PotlatchDeltic has not requested, and EPA has not issued any pre-construction permits to PotlatchDeltic for any of these projects. More recently, PotlatchDeltic did request PSD (VOC) and minor NSR (CO, NO_X, PM, PM10 and PM2.5) permits for the construction of kiln LK-6. Region 10 issued permits authorizing that project with conditions on June 21, 2019, which permits have since been amended on several occasions. The PSD permit is Permit No. R10PSD00103; the minor NSR permit is Permit No. R10TNSR01803.

New Source Performance Standards. The EPA considered the applicability of four combustion-related NSPS standards to boilers PB-1 and PB-2 at SMC, each 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). NSPS Subparts D and Da do not apply to either PB-1 or PB-2 because each boiler's heat input capacity is less than one-half the applicability threshold of 250 MMBtu/hr. PB-2's heat input capacity of 113 MMBtu/hr is within the applicability range of 100 MMBtu/hr to 250 MMBtu/hr of NSPS Subpart Db. But given that PB-2 was constructed in 1966 before the June 19, 1984 applicability date, and because it has not been modified or reconstructed since that date based on information provided by PotlatchDeltic, NSPS Db does not apply. PB-1's heat input capacity of 43 MMBtu/hr is within the applicability range of 10 MMBtu/hr and 100 MMBtu/hr of NSPS Dc. But given that PB-1 was constructed in 1964 before the June 9, 1989 applicability date, and because it has not been modified or reconstructed since that date based on information provided by PotlatchDeltic, NSPS Dc does not apply. According to PotlatchDeltic's application, PB-1 was last modified in 1979 when the Wellons firing system was installed.

The five diesel fuel storage tanks and one gasoline fuel storage tank, dates of construction unknown, are not subject to 40 CFR Part 60, Subparts K, Ka and Kb because each tank's storage capacity is less than the subpart K and Ka threshold of 40,000 gallons and less than the subpart Kb threshold of 75 cubic meters (19,813 gallons). The three propane fuel tanks, storage capacity and date of construction unknown, are not subject to 40 CFR Part 60, Subparts K, Ka and Kb because each tank is a pressure vessel designed to operate in excess of 204.9 kPa with no emission to the atmosphere. The vapor pressure of propane is about 102 psi or 703 kPa.

EPA considered the applicability of 40 CFR 60, Subpart IIII (Stationary Compression Ignition Internal Combustion Engines), a combustion-related NSPS, to the two CI engines at SMC that provide mechanical energy for water pumps used solely for fire suppression, emergency fire pump engines IC-1 and IC-2. For certified National Fire Protection Agency fire pump engines (as is the case for IC-1 and IC-2), NSPS IIII applies to the owner or operator if the engine was ordered after July 11, 2005, and the engine was manufactured after July 1, 2006. NSPS Subpart IIII therefore applies to the two CI engines installed at SMC. Compliance was required upon startup.

40 CFR 60, Subpart IIII requirements that do not apply to SMC for engines IC-1 and IC-2 are not included in the permit. Requirements that apply generally to all subject sources but do not create specific requirements for PotlatchDeltic (e.g., applicability provisions, definitions, provisions regarding delegation) are incorporated by reference into the permit. Because 40 CFR 60, Subpart IIII applies to engines IC-1 and IC-2, Subpart A of Part 60 (the general provisions) also applies, as explained in 40 CFR 60.1(a). NSPS Subpart A requirements that do not apply to SMC are not included in the permit. Requirements that apply generally to all subject sources but do not create specific requirements for PotlatchDeltic (e.g., applicability provisions, definitions, provisions regarding delegation) are incorporated by reference into the permit. Applicable requirements in 40 CFR 60, Subparts IIII and A with specific requirements have been included in Section 8 of the permit. Appendix B to this statement of basis contains tables that cross reference the applicable requirements in Subparts IIII and A to conditions in Section 8 of the permit.

Another combustion-related NSPS standard considered for applicability to the nine SI engines at SMC that are stationed throughout the mill to serve nine separate generators that supply electricity to different activities only when electricity from the grid is unavailable, emergency engines IC-3 to IC-11, is 40 CFR 60, Subpart JJJJ (Stationary Spark Ignition Internal Combustion Engines). For engines with maximum power less than 25 hp (as is the case for IC-3, IC-7 and IC-8, and IC-10 and IC-11), NSPS JJJJ applies to the owner or operator if the engine was ordered after June 12, 2006, and the engine was manufactured on or after July 1, 2008. For emergency engines with maximum power greater than 25 hp (as is the case for IC-4 through IC-6 and IC-9), NSPS JJJJ applies to the owner or operator if the engine was ordered after June 12, 2006, and the engine was manufactured on or after January 1, 2009. NSPS Subpart JJJJ applies to all the SI engines installed at SMC. Compliance was required upon startup.

40 CFR 60, Subpart JJJJ requirements that do not apply to SMC for engines IC-3 to IC-11 are not included in the permit. Requirements that apply generally to all subject sources but do not create specific requirements for PotlatchDeltic (e.g., applicability provisions, definitions, provisions regarding delegation) are incorporated by reference into the permit. Because 40 CFR 60, Subpart JJJJ applies to engines IC-3 to IC-11, Subpart A of Part 60 (the general provisions) also applies, as explained in 40 CFR 60.1(a). NSPS Subpart A requirements that do not apply to SMC are not included in the permit. Requirements that apply generally to all subject sources but do not create specific requirements for PotlatchDeltic (e.g., applicability provisions, definitions, provisions regarding delegation) are incorporated by reference into the permit. Applicable requirements in 40 CFR 60, Subparts JJJJ and A with specific requirements have been included in Section 9 of the permit. Appendix B to this statement of basis contains tables that cross reference the applicable requirements in Subparts JJJJ and A to conditions in Section 9 of the permit.

<u>National Emission Standards for Hazardous Air Pollutants (NESHAP)</u>. Certain NESHAP standards promulgated under 40 CFR Part 63 apply only 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. As discussed in Section 2.4 above, SMC is a major source of HAP emissions regardless of whether the LDD is considered part of the same source.

EPA considered the applicability of several major source NESHAP standards. NESHAP Subparts DDDDD (Industrial, Commercial and Institutional Boilers and Process Heaters at Major Sources) applies to biomass boilers and DDDD (Plywood and Composite Wood Products Manufacture) applies to veneer dryers, miscellaneous coating operations and lumber kilns. Both standards apply to activities at SMC. The compliance dates for the NESHAP standards are January 31, 2016 for Subpart DDDDD and October 1, 2007 for Subpart DDDD. EPA granted PotlatchDeltic's request to extend the NESHAP Subpart DDDD compliance date to October 1, 2008 to provide the mill an additional 12 months to install control equipment to reduce veneer dryer heating section HAP emissions. Because each of SMC's two synthetic patch lines (PP) is an existing affected source (and not new), neither line is a Group 1 Miscellaneous Coating Operation under NESHAP Subpart DDDD. Therefore, the use of non-HAP coatings is not required of PotlatchDeltic for PP.

40 CFR 63, Subpart DDDDD requirements that do not apply to SMC for PB-1 and PB-2 are not included in the permit. Requirements that apply generally to all subject sources but do not create specific requirements for PotlatchDeltic (e.g., applicability provisions, definitions, provisions regarding delegation) are incorporated by reference into the permit. Because 40 CFR 63, Subpart DDDDD applies to PB-1 and PB-2, Subpart A of Part 63 (the general provisions) also applies, as explained in 40 CFR 63.1(a)(4). NESHAP Subpart A requirements that do not apply to SMC are not included in the permit. Requirements that apply generally to all subject sources but do not create specific requirements for PotlatchDeltic (e.g., applicability provisions, definitions, provisions regarding delegation) are incorporated by reference into the permit. Applicable requirements in 40 CFR 63, Subparts DDDDD and A with specific requirements have been included in Section 5 of the permit. Appendix B to this statement of basis contains tables that cross reference the applicable requirements in Subparts DDDDD and A to conditions in Section 5 of the permit.

Permit Conditions 5.6.1 (NESHAP DDDDD annual boiler tune-up requirement) and 5.7.2 (NESHAP DDDDD 30-day rolling average minimum oxygen operating limit) apply to PB-1 and PB-2 because neither boiler is operated with the assistance of an oxygen trim system as that term is defined in 40 CFR 63.7575. If PotlatchDeltic chooses to install and operate a continuous oxygen trim system that maintains an optimum air to fuel ratio, the NESHAP DDDDD requirements in those permit conditions no longer apply. Different NESHAP DDDDD requirements become applicable. For instance, instead of being required to conduct a tune-up of the boiler every year, a tune-up is required every 5 years. See 40 CFR 63.7540(a)(12). The 30-day rolling oxygen operating limit is replaced with the requirement to operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test. See 40 CFR 63.7525(a)(7) and Row 9 to Table 8 of NESHAP DDDDD. "Lowest hourly average" in 40 CFR 63.7525(a)(7) means the lowest test-run average.[7] PB-1 underwent performance testing to demonstrate compliance with the applicable CO emission limit most recently on June 12, 2024, and the lowest hourly (i.e., test-run) average oxygen content was 7.3%, wet. PB-2 underwent performance testing to demonstrate compliance with the applicable CO emission limit most recently on June 11, 2024, and the lowest hourly (i.e., test-run) average oxygen content was 5.9%, wet. These requirements (different from the ones in the permit) become applicable at the conclusion of tuning period for the oxygen trim system.

40 CFR 63, Subpart DDDD requirements that do not apply to SMC for VD-1 to VD-4, RCO, ES, WP, SCL, LK-5 and LK-6 are not included in the permit. Requirements that apply generally to all subject sources but do not create specific requirements for PotlatchDeltic (e.g., applicability provisions, definitions, provisions regarding delegation) are incorporated by reference into the permit. Because 40 CFR 63, Subpart DDDD applies to VD-1 to VD-4, RCO, ES, WP, SCL, LK-5 and LK-6, Subpart A of Part 63 (the general provisions) also applies, as explained in 40 CFR 63.1(a)(4). NESHAP Subpart A requirements that do not apply to SMC are not included in the permit. Requirements that apply generally to all subject sources but do not create specific requirements for PotlatchDeltic (e.g., applicability provisions,

[7] See discussion of intent for similar provision expressed by EPA's OAQPS in a January 11, 2017 email correspondence, document 7j in the administrative record for this permit action. Lowest hourly average means lowest test-run average.

definitions, provisions regarding delegation) are incorporated by reference into the permit. Applicable requirements in 40 CFR 63, Subparts DDDD and A with specific requirements have been included in Sections 6 and 7 of the permit. Appendix B to this statement of basis contains tables that cross reference the applicable requirements in Subparts DDDD and A to conditions in Sections 6 and 7 of the permit. Because LK-5 and LK-6 are not subject to any NESHAP Subpart A and DDDD requirements other than the requirement (now obsolete) to submit an initial notification pursuant to 40 CFR 63.2252, Section 10 neither includes nor incorporates any NESHAP Subpart A or DDDD requirements.

A third NESHAP standard, Subpart ZZZZ (Reciprocating Internal Combustion Engines) applies to certain engines regardless of whether the source is major for HAP. All eleven of the emergency engines at SMC are subject to NESHAP ZZZZ. Engines IC-1 thru IC-11 are considered "new" pursuant to 40 CFR 63.6590(a)(2)(ii). Engines IC-1 and IC-2 comply with Engine NESHAP by complying with NSPS IIII (with no additional substantive NESHAP ZZZZ requirements) pursuant to 40 CFR 63.6590(c)(7). Engines IC-3 through IC-11 comply with the Engine NESHAP by complying with NSPS JJJJ (with no additional substantive NESHAP ZZZZ requirements) pursuant to 40 CFR 63.6590(c)(4).

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 the SMC. 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, the EPA promulgated a Federal Implementation Plan (FIP) for Reservations in Idaho, Oregon and Washington, commonly referred to as the Federal Air Rules for Reservations (FARR). The 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 apply on the Coeur d'Alene Reservation (Sections 123, 124, 125, 126, 129, 130, 131, 135, 137, 138 and 139) are identified at 40 CFR 49.9926 and codified into the FIP at 40 CFR 49.9930. Notably, 40 CFR 49.128 (Rule for limiting particulate matter emissions from wood products industry sources) does not currently apply on the Coeur d'Alene Reservation. FARR requirements that do not apply to SMC are not included in the permit. Requirements that apply generally to all subject sources but do not create specific requirements for PotlatchDeltic (e.g., applicability provisions, definitions, provisions regarding delegation) are incorporated by reference into the permit. Applicable requirements in the FARR with specific requirements have been included in Sections 3 through 13 of the permit. Appendix B to this statement of basis contains tables that cross reference the applicable requirements in the FARR to conditions in the permit.

Compliance Assurance Monitoring. CAM applies at time of initial Title V permit issuance for emission units that (a) are subject to an emission limit, (b) use 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 64.5(a). Table 4-1 below illustrates the results of an applicability analysis for those emission units that use a control device to comply with a CAM-eligible emission limit.[8] In no instance is an emission unit's PM, PM10 or PM2.5 PTE greater than the 100 tpy applicability threshold value. Therefore, CAM does not apply to any underlying emission limits for this initial Title V permitting action. See Appendix A of this statement of basis for the calculations supporting post-control PTE values appearing in Table 4-1.

[8] Pursuant to 40 CFR 64.2(b)(1)(i), neither NESHAP Subpart DDDDD (for PB-1 and PB-2) nor NESHAP Subpart DDDD (for VD-1, VD-2, VD-3 and VD-4) are CAM-eligible emission limits because each is a post-1990 NESHAP.

Table 4-1: CAM Applicability at Time of Initial Title V Permit

EU ID	Pollutant	Control Device	CAM-Eligible Emission Limit	Post-Control PTE (tpy)	Does CAM Apply for Initial Title V Permit?
EU-1: PB-1	PM, PM10, PM2.5	MC-1 & DESP-1	VE ≤ 20% opacity, 6-min avg PM ≤ 0.2 gr/dscf @ 7% O_2, 3-hr avg PM2.5 ≤ 11.09 lb/day PM2.5 ≤ 1.97 tpy	PM: 5.1 PM10/2.5: 1.97	No
EU-1: PB-2	PM, PM10, PM2.5	MC-2 & DESP-2	VE ≤ 20% opacity, 6-min avg PM ≤ 0.2 gr/dscf @ 7% O_2, 3-hr avg PM2.5 ≤ 20.63 lb/day PM2.5 ≤ 3.59 tpy	PM: 21.2 PM10/2.5: 3.59	No
EU-2: VDHS-1	PM, PM10, PM2.5	RCO	VE ≤ 20% opacity, 6-min avg PM ≤ 0.1 gr/dscf, 3-hr avg	PM: 0.5 PM10/2.5: 1.0	No
EU-2: VDHS-2	PM, PM10, PM2.5	RCO	VE ≤ 20% opacity, 6-min avg PM ≤ 0.1 gr/dscf, 3-hr avg	PM: 0.4 PM10/2.5: 0.9	No
EU-2: VDHS-3	PM, PM10, PM2.5	RCO	VE ≤ 20% opacity, 6-min avg PM ≤ 0.1 gr/dscf, 3-hr avg	PM: 1.0 PM10/2.5: 2.1	No
EU-2: VDHS-4	PM, PM10, PM2.5	RCO	VE ≤ 20% opacity, 6-min avg PM ≤ 0.1 gr/dscf, 3-hr avg	PM: 1.0 PM10/2.5: 2.0	No
EU-7: PCWR-CS-SD	PM, PM10, PM2.5	BH-1	VE ≤ 20% opacity, 6-min avg PM ≤ 0.1 gr/dscf, 3-hr avg	PM: 1.1 PM10/2.5: 1.1	No
EU-7: PCWR-PM-SH	PM, PM10, PM2.5	BH-2	VE ≤ 20% opacity, 6-min avg PM ≤ 0.1 gr/dscf, 3-hr avg PM2.5 ≤ 6.53 lb/day PM2.5 ≤ 1.19 tpy	PM: 11.3 PM10/2.5: 1.19	No
EU-7: PCWR-PM-SD	PM, PM10, PM2.5	BH-3	VE ≤ 20% opacity, 6-min avg PM ≤ 0.1 gr/dscf, 3-hr avg PM2.5 ≤ 5.77 lb/day PM2.5 ≤ 1.05 tpy	PM: 10.1 PM10/2.5: 1.05	No
EU-7: PCWR-PWM-PTB	PM, PM10, PM2.5	BH-4	VE ≤ 20% opacity, 6-min avg PM ≤ 0.1 gr/dscf, 3-hr avg	PM: 2.3 PM10/2.5: 2.3	No No
EU-7: PCWR-PM-PTB	PM, PM10, PM2.5	BH-4	VE ≤ 20% opacity, 6-min avg PM ≤ 0.1 gr/dscf, 3-hr avg PM2.5 ≤ 3.95 lb/day PM2.5 ≤ 0.62 tpy	PM: 2.3 PM10/2.5: 0.62	No
EU-7: PCWR-PM-PSB	PM, PM10, PM2.5	BH-5	VE ≤ 20% opacity, 6-min avg PM ≤ 0.1 gr/dscf, 3-hr avg PM2.5 ≤ 3.95 lb/day PM2.5 ≤ 0.62 tpy	PM: 2.3 PM10/2.5: 0.62	No
EU-7: PCWR-PWM-SDD		BH-6	VE ≤ 20% opacity, 6-min avg	PM: 24.4	No

EU ID	Pollutant	Control Device	CAM-Eligible Emission Limit	Post-Control PTE (tpy)	Does CAM Apply for Initial Title V Permit?
	PM, PM10, PM2.5		PM ≤ 0.1 gr/dscf, 3-hr avg	PM10/2.5: 24.4	
EU-7: PCWR-PWM-TB	PM, PM10, PM2.5	BH-7	VE ≤ 20% opacity, 6-min avg PM ≤ 0.1 gr/dscf, 3-hr avg	PM: 1.5 PM10/2.5: 1.5	No
EU-7: PCWR-PWM-SB	PM, PM10, PM2.5	BH-8	VE ≤ 20% opacity, 6-min avg PM ≤ 0.1 gr/dscf, 3-hr avg	PM: 11.6 PM10/2.5: 11.6	No
EU-7: PCWR-PWM-ISB	PM, PM10, PM2.5	BH-9	VE ≤ 20% opacity, 6-min avg PM ≤ 0.1 gr/dscf, 3-hr avg	PM: 16.0 PM10/2.5: 16.0	No
EU-7: PCWR-SM-SD	PM, PM10, PM2.5	BH-10	VE ≤ 20% opacity, 6-min avg PM ≤ 0.1 gr/dscf, 3-hr avg PM2.5 ≤ 31.87 lb/day PM2.5 ≤ 4.97 tpy	PM: 18.2 PM10/2.5: 4.97	No
EU-7: PCWR-SM-SDB	PM, PM10, PM2.5	BH-11	VE ≤ 20% opacity, 6-min avg PM ≤ 0.1 gr/dscf, 3-hr avg PM2.5 ≤ 6.98 lb/day PM2.5 ≤ 1.09 tpy	PM: 4.0 PM10/2.5: 1.09	No
EU-7: PCWR-PM-PSB	PM, PM10, PM2.5	BH-12	VE ≤ 20% opacity, 6-min avg PM ≤ 0.1 gr/dscf, 3-hr avg		No

At the time of Title V permit renewal, or sooner in the case of a significant permit modification (emission unit-specific), CAM will apply based upon whether the emission unit's pre-control PTE is greater than the relevant threshold value pursuant to 40 CFR 64.5(b).

Chemical Accident Release Program. PotlatchDeltic has not reported storing a regulated substance above the threshold quantity. The permit contains a placeholder provision requiring the Permittee to comply with the chemical accident prevention provisions in 40 CFR part 68 in a timely manner if it becomes subject.

Protection of Stratospheric Ozone. The provisions of 40 CFR part 82, subparts B and F apply to facilities that handle ozone depleting substances (e.g. refrigerants). The permit contains conditions that require the Permittee to manage ozone depleting substances and maintain records according to these subparts.

Acid Rain Program. Title IV of the CAA authorizes 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 electricity. Neither of the two boilers at the SMC are a "unit" or an "affected unit" as defined in 40 CFR 72.2 because neither boiler produces electricity.

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 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 required.

4.2 Other Federal Requirements and Responsibilities

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 1873 Executive Order and subsequent series of treaty agreements. 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 Air and Radiation Division has contacted the Coeur d'Alene Tribe to invite consultation on the SMC Title V operating permit application.

Endangered Species Act (ESA). Under section 7(a)(2) of the ESA, federal agencies are required to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of any listed, threatened, or endangered species, or destroy or adversely modify the designated critical habitat of such species. 16 U.S.C. § 1536(a)(2). The U.S. Fish and Wildlife Service and National Marine Fisheries Service have promulgated ESA implementing regulations at 50 CFR Part 402.

The CAA title V permit program requires the EPA to issue a permit specifically describing the permittee's existing pollution control obligations under the CAA. A title V permit does not generally create any new substantive requirements, but rather simply incorporates all existing CAA requirements, called "applicable requirements," into a single unified operating permit applicable to a particular facility. The title V permit EPA is issuing to PotlatchDeltic does not authorize the construction of new emission units, or emission increases from existing units, nor does it otherwise authorize any physical modifications to the facility or its operations. The EPA has concluded that the permit appropriately incorporates all existing CAA requirements applicable to the facility. The EPA lacks discretion in this title V permitting decision to take action that could inure to the benefit of any listed species or their critical habitat. The EPA has concluded that issuance of this permit will have no effect on any listed species or their critical habitat. Accordingly, this permit action is consistent with the requirements of ESA section 7.

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. Consequently, no adverse effects are expected, and further review under NHPA is not required.

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, the 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. Additionally, the Agency's Policy on Environmental Justice for Working with Federally Recognized Tribes and Indigenous Peoples, issued

July 24, 2014, asserts EPA's commitment to integrate EJ principles into work with federally recognized tribes and indigenous peoples.

EJScreen is an EPA environmental justice mapping and screening tool that provides EPA with a nationally consistent dataset and approach for combining environmental and demographic socioeconomic indicators. EJScreen users choose a geographic area; the tool then provides demographic socioeconomic and environmental information for that area. All of the EJScreen indicators are publicly-available data. EJScreen simply provides a way to display this information and includes a method for combining environmental and demographic indicators into 13 EJ indexes organized by medium conveying the environmental indicator as follows:

- Air (6)
  - Particulate matter with aerodynamic diameter less than 2.5 micrometers
  - Ozone
  - Diesel particulate matter
  - Air toxics cancer risk
  - Air toxics respiratory hazard index
  - Toxic releases to air
- Air/other (1)
  - Traffic proximity and volume
- Dust/lead paint (1)
  - Lead paint
- Waste/air/water (4)
  - Superfund proximity
  - Risk management plan facility proximity
  - Hazardous waste proximity
  - Underground storage tanks
- Water (1)
  - Wastewater discharge

According to EPA's EJSCREEN Version 2.2 environmental justice screening and mapping tool, 6% of the 3,634 persons within a two-mile radius of the facility identify as people of color and 44% are classified as low income. "People of color" refers to individuals that list their racial status as a race other than white alone and/or list their ethnicity as Hispanic or Latino. That is, all people other than non-Hispanic white-alone individuals. The word "alone" in this case indicates that the person is of a single race, not multiracial. "Low income" individuals are those whose ratio of household income to poverty level in the past twelve months was less than 2 (as a fraction of individuals for whom ratio was determined). None of the thirteen "EJ Indexes" reported by EJSCREEN for the area within a two-mile radius of the facility meet or exceed the 80th percentile among national block groups.

The CAA title V permit program requires the EPA to issue a permit specifically describing the permittee's existing pollution control obligations under the CAA. A title V permit does not generally create any new substantive requirements, but rather simply incorporates all existing CAA requirements, called "applicable requirements," into a single unified operating permit applicable to a particular facility. As required by the CAA, Region 10 has created monitoring and recordkeeping requirements in the PotlatchDeltic permit when underlying monitoring/recordkeeping requirements either do not exist or lack sufficiency. The title V permit EPA is issuing to PotlatchDeltic does not authorize the construction of new emission units, or emission increases from existing units, nor does it otherwise authorize any physical modifications to the facility or its operations. The EPA has concluded that the permit appropriately incorporates all existing CAA requirements applicable to the facility and includes the monitoring, recordkeeping, and reporting requirements sufficient to assure compliance with these requirements.

Issuance of this permit is consistent with Executive Order 12898's stated goals of achieving environmental justice for people of color, low-income populations, and Indigenous peoples.

Because 96% of households within a two-mile radius of the facility speak English, EPA will provide public notice of this draft permit action in English only. In accordance with 40 CFR 71.11, EPA will solicit public input on the draft permit for 30 days. EPA will also offer to hold a public hearing if there is sufficient interest. Beyond the regulatory requirements, Executive Order 12898 does not mandate any specific public outreach requirements in general or in the Title V permitting context. EPA has determined that the planned level of outreach will allow interested parties sufficient opportunity to comment on the draft permit and raise any concerns related to environmental justice.

5. Permit Content

This Title V operating permit compiles all of the applicable requirements that apply to the Permittee. Additional monitoring, recordkeeping and reporting requirements have been included where Region 10 has determined it is necessary for this source to assure compliance. 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 fourteen 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 – Emission Unit #1 (EU-1) – PB-1 CE Boiler and PB-2 Riley Boiler
- Permit Section 6: Unit-Specific Requirements – Emission Unit #2 (EU-2) – Veneer Dryers VD-1, VD-2, VD-3 and VD-4
- Permit Section 7: Unit-Specific Requirements – Emission Unit #3 (EU-3) – Oil and Edge Seal Line (ES), Wood Putty Patching (WP) and Surface Coating Logos (SCL)
- Permit Section 8: Unit-Specific Requirements – Emission Unit #4 (EU-4) – Compression Ignition Internal Combustion Engines IC-1 and IC-2
- Permit Section 9: Unit-Specific Requirements – Emission Unit #5 (EU-5) – Spark Ignition Internal Combustion Engines IC-3, IC-4, IC-5, IC-6, IC-7, IC-8, IC-9, IC-10 and IC-11
- Permit Section 10: Unit-Specific Requirements – Emission Unit #6 (EU-6) – Lumber Drying Kiln LK-5 and Lumber Drying Kiln LK-6
- Permit Section 11: Unit-Specific Requirements – Emission Unit #7 (EU-7) – Pneumatic Conveyance and Dust Capture Systems
- Permit Section 12: Unit-Specific Requirements – Emission Unit #8 (EU-8) – Plywood Presses PV-1 and PV-2
- Permit Section 13: Unit-Specific Requirements – Emission Unit #9 (EU-9) – Plant Traffic (PT)
- Permit Appendix: NESHAP Subpart A Requirements Applicable to EU-1, EU-2 and EU-3

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.

Permit Section 2 – Standard Terms and Conditions

This permit section includes generic compliance terms that are required in all Title V permits.

Permit Condition 2.1 makes clear that the language in the underlying regulations takes precedence over paraphrased language in the permit. Where there is a difference between the language in the permit and an underlying regulation, the wording in the underlying regulation governs except as noted in Condition 2.1. This permit condition also notes some underlying authorities that may have been used to impose additional requirements in this permit. For instance, 40 CFR 71.6(a)(3)(i)(B) provides authority to include monitoring requirements when an applicable underlying emission limitation is not accompanied by monitoring. In addition, 40 CFR 71.6(c)(1) provides authority to include additional monitoring requirements when an applicable underlying emission limitation is accompanied by monitoring that is not sufficient to assure compliance with the limitation.[9]

Permit Condition 2.2 explains the obligations of complying with all conditions of the part 71 permit and any noncompliance with the permit constitutes a violation of the CAA.

Permit Condition 2.3 explains that need to halt or reduce activity is not a defense to maintain compliance with the conditions of 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.

Permit Condition 2.6 incorporates the credible evidence rule as reflected in the various applicable requirements cited as authority for this condition. It makes clear that language in the permit stating "compliance is determined with" or "demonstrate compliance by" does not preclude the use of other credible evidence to demonstrate that the Permittee is not in compliance with an applicable requirement.

Permit Conditions 2.7 and 2.8 incorporate the Part 71 provisions regarding permit modification, revocation, reopening, reissuance, and termination for cause.

Permit Conditions 2.9 through 2.11 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 2.12 through 2.14 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. Conditions 2.13.3 and 2.13.4 were added to satisfy the requirement in 40 CFR 71.6(c)(1) to include compliance certification, testing, monitoring, recordkeeping, and reporting sufficient to assure compliance with the applicable requirement.

Permit Section 3 – General Requirements

This permit section includes conditions implementing requirements generally applicable to all facilities. In some cases, facility-specific testing, monitoring, recordkeeping and reporting requirements for these permit conditions are included 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

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[9] In the Matter of BP Amoco Chemical Company, Texas City Chemical Plant, Galveston County, Texas, Order on Petition No. VI-2017-6 (July 20, 2021). See page 29 of the order. Permitting authorities must incorporate applicable monitoring requirements into the Title V permit, add monitoring when no underlying monitoring exists, and supplement existing monitoring that is not sufficient to assure compliance with permit terms and conditions.

Section 3 of the permit as well as the facility-specific and unit-specific requirements in Sections 4 through 13.

Permit Conditions 3.1 and 3.2 are general compliance schedule requirements. Because EPA has not determined that the Permittee is in non-compliance with any applicable requirements at the time of permit issuance, nor is the company subject to an administrative order or consent decree containing compliance actions, there is no issue-specific compliance schedule in the permit. In Conditions 5.5.4 and 5.5.6, the permit includes revised NESHAP DDDDD CO and PM emission limits for which compliance must be achieved on and after October 6, 2025.

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. If the Permittee performs any open burning, recordkeeping requirements specific to open burning found in Permit Condition 3.33 will apply.

Permit Conditions 3.9 through 3.11 limit visible emissions, require the use of either RM9 or a continuous opacity monitoring system (COMS) for determining compliance with the limit, and provide exceptions to the rule. RM9 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 a certified reader 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 NESHAP Subpart DDDDD) a COMS to monitor visible emissions generated by boilers PB-1 and PB-2, the exception in Condition 3.11.2 does apply to these boilers, but only with respect to the FARR limit. The exception for start-up, soot blowing, and grate cleaning does not extend to the NESHAP Subpart DDDDD visible emissions operating limit.

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 4.8 through 4.13. These general requirements, however, do not apply to the boilers as noted in Condition 4.14 given the use of a COMS. Emergency engines IC-1 thru IC-11 are also exempt from the monthly survey given their infrequent use. The Permittee is required to observe their emissions annually. The monthly (quarterly for those activities that qualify) walkthrough requirement is also not applicable to visible emissions exhausted from veneer dryer heating section bypass stacks. Bypass stack emissions must be observed upon each occurrence.

Permit Conditions 3.12 through 3.17 restrict fugitive particulate matter emissions and require a plan 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 4.8 through 4.13, as long as both requirements are fully complied with. Permit Conditions 3.12 through 3.17 reflect requirements in the FARR that apply facility-wide. Those same requirements were included in Permit No. R10TNSR01803 (conditions 3.14.1 through 3.14.8 and 4.16 through 4.20 of that permit) regulating certain components of the facility. The requirements have been combined into one set of permit conditions applicable facility-wide.

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 requirements 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. The requirements were added to satisfy the requirement in 40 CFR 71.6(c)(1) to include testing, monitoring, recordkeeping, and reporting sufficient to assure compliance with the applicable requirement. If there is a conflict between these permit conditions and an emission unit-specific permit condition, the specific permit condition governs. 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 3.31 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 2.12.

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.

Permit Condition 3.35 sets the duration that records must be maintained. Title V, the FARR and Permit No. R10PSD00103 (condition 4.4 of that permit) and R10TNSR01803 (condition 4.8 of that permit) require that records must be maintained for five years. The Title V recordkeeping requirement in 40 CFR 71.6(a)(3)(ii) is broad in scope while the recordkeeping requirements in the underlying FARR provisions and construction permits apply narrowly to certain emission units for specified records. The requirements have been combined into a single permit condition that applies facility-wide. If there is ever a conflict between the resultant requirements and a more restrictive emission unit-specific permit condition, the specific permit condition applies.

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. This includes, but is not limited to, notifying Region 10 if the application no longer reflects the type of fuel actually being fired in a combustion unit.

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 2.12. Section 502(b)(10) changes are allowed in Permit Conditions 2.13. The requirement that the Permittee attach each notice to its copy of the permit was added to satisfy the requirement in 40 CFR 71.6(c)(1) to include monitoring, recordkeeping, and reporting sufficient to assure compliance with the applicable requirement.

Permit Condition 3.40 specifies that all submittals (except for fee payments – see Permit Condition 3.43; and annual FARR registration – see Permit Condition 3.46.2) are to be submitted to EPA electronically via CEDRI unless the submittal contains confidential business information (CBI). This requirement supersedes reporting required in Permit No.'s R10PSD00103 and R10TNSR01803. Submittals containing CBI must be sent hardcopy to the addresses specified or electronically. Copies of each document sent to EPA must be sent to the Tribal Air Quality Coordinator except those containing CBI.

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; 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 based on current information. As explained in Section 3.2 of this statement of basis, Region 10 expects the emission estimation techniques listed in this statement of basis to be used to calculate the annual actual 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.

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, Region 10 expects the emission estimation techniques listed in this statement of basis to 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 to EPA electronically via FORS unless it contains CBI. The requirement was added to satisfy the requirement in 40 CFR 71.6(c)(1) to include monitoring, recordkeeping, and reporting sufficient to assure compliance with the applicable requirement. Submittals containing CBI must be sent in hardcopy to the addresses specified or electronically. Copies of each document sent to EPA must be sent to the Tribal Air Quality Coordinator except those containing CBI.

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.

Permit No. R10PSD00103 (conditions 5.2 and 5.3 of that permit) and R10TNSR01803 (conditions 5.4 and 5.5 of that permit) require annual monitoring reports and prompt deviation reports. The requirements have been combined into a single permit condition that applies facility-wide with more timely and frequent reporting of monitoring performed. Prompt deviation reporting via CEDRI (not by telephone as specified in the underlying permits) is required.

Just as excursions under 40 CFR part 64 (indicator out of range) are deviations pursuant to 40 CFR 71.6(a)(3)(iii)(C)(4), excursions under Condition 5.15 are also deviations. See Condition 3.48.1.5. Reporting of these deviations (excursions under Condition 5.15) is required no more frequently than semi-annually, and Condition 5.15.4 specifies the information to be reported.

Permit Condition 3.49 requires an annual compliance certification. The Permittee must certify compliance with the permit conditions. Consistent with Permit Condition 2.6, however, if the Permittee is aware of any information that indicates noncompliance, that information must be included in the annual compliance certification. For a year when the permit is renewed or revised, the Permittee must address each permit for the time that permit was in effect. Forms for the annual compliance certifications may be obtained on the internet at https://www.epa.gov/title-v-operating-permits/epa-issued-operating-permits. The requirement to note in the annual compliance certification excursions under Condition 5.15 as possible exceptions to compliance of the underlying NESHAP DDDDD emission limit was added to satisfy the requirement in 40 CFR 71.6(c)(1) to include compliance certification sufficient to assure compliance with the applicable requirement.

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 must request an administrative amendment of the permit if the responsible official for the facility changes. The requirement to certify "any document" submitted to the EPA as opposed to "any application form, report or compliance certification" was added to satisfy the requirement in 40 CFR 71.6(c)(1) to include monitoring, recordkeeping, and reporting sufficient to assure compliance with the applicable requirement.

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 2.9 through 2.11, 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.

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 13 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.

Permit Conditions 4.2 and 4.5 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 two boilers. To demonstrate compliance, the underlying rule requires the Permittee to keep records showing that only wood residue is burned. The naturally occurring sulfur content of wood waste is normally much less than the limit of 2 percent by weight. An upper bound estimate for the sulfur content of bark is 0.2 percent by weight (dry).[10] PB-1 and PB-2 are the only emission units at SMC that combust solid fuel.

Permit Conditions 4.3 and 4.6 limit the sulfur content of the diesel fuel burned in any combustion device, specify the method for determining compliance and specify the monitoring and recordkeeping. Under NSPS subpart IIII, the two engines may only burn ULSD fuel. The underlying FARR rule allows the Permittee to keep vendor records showing that the sulfur content of the diesel fuel is below the limit of 0.3 percent by weight (3,000 ppm) for No. 1 diesel and 0.5 percent by weight (5,000 ppm) for No. 2 diesel. Because ULSD fuel has a maximum sulfur content of 15 ppm, the Permittee can satisfy the requirement by having vendor records that document that only ULSD fuel is delivered. IC-1 and IC-2 are the only emission units at SMC that combust liquid fuel.

Permit Conditions 4.4 and 4.7 limit the sulfur content of the propane fuel burned in any combustion device, specify the method for determining compliance and specify the monitoring and recordkeeping. The facility burns only propane in the eight SI internal combustion engines. The underlying rule allows the Permittee to keep vendor records showing that the sulfur content of the propane is below the FARR limit of 1.1 g/dscm

A concentration of 1.1 g/dscm limit is equivalent to 918 ppmw as illustrated through the following calculation based upon an equation in a table entitled, “Conversion Factors for Common Air Pollution Measurements: Atmospheric Gases” on page A-27 of Appendix A to AP-42: 918 ppmw = (1.1 g/m3) X (1000 mg/g) X (0.8347). Per the GPA Liquefied Petroleum Gas (LPG) Specifications Standard 2140-97, commercial propane is allowed to have the highest sulfur content among the four liquefied petroleum gas products (the other three being commercial butane, commercial b-p mixtures and propane HD-5). Commercial propane is limited to 185 ppmw, so the Permittee can satisfy the requirement to have vendor records by documenting that any of the four GPA-designated LPG products is burned. RCO, IC-3, IC-4, IC-5, IC-6, IC-7, IC-8, IC-9 IC-10 and IC-11 are the only emission units at SMC that combust gaseous fuel. Permit Condition 3.37 requires PotlatchDeltic to notify Region 10 in the event the mill decides to combust gaseous fuel other than propane in RCO and emergency SI engines

Permit Conditions 4.8 through 4.13 require a monthly survey (also referred to as 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 cannot 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) 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 monthly survey required in this permit condition as long as both requirements are fully complied with. Permit Condition 4.9 relaxes survey frequency from monthly to quarterly for those activities documented to have not been generating visible or fugitive emissions for three consecutive monthly surveys. This opportunity for reduced monitoring frequency is not available to those activities using an air pollution control device or applying a fugitive dust suppressant. The Permittee is required to

[10] 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

maintain a list of the potential sources of fugitive dust or visible particulate emissions for which it is conducting surveys, and the list must identify the monitoring frequency (monthly or quarterly) for each activity. Note that not every emission generating activity is a potential source of fugitive dust or visible particulate emissions. For example, PotlatchDeltic is not required to conduct a visual survey of liquid or gaseous fuel storage tanks because the tanks are not potential sources of fugitive dust or visible particulate emissions.

These permit conditions were included in Permit No. R10TNSR01803 (conditions 4.9 through 4.15) authorizing construction of kiln LK-6 and regulating certain components of the facility. At the time Region 10 issued the initial minor NSR permit and as explained on page 24 of the June 2019 Permit Analysis, EPA determined that the walkthroughs adequately assure compliance with the daily and annual PM2.5 emission limits applicable to EU-7's PCWR-PM-SH, PCWR-PM-SD, PCWR-PM-PTB, PCWR-PM-PSB, PCWR-SM-SD, PCWR-SM-SDB and PCWR-SM-CH. Since June 2019 and as required by the minor NSR permit, the Permittee conducted performance testing of PCWR-PM-SH and PCWR-PM-SD (PM/PM10/PM2.5 emissions controlled by their respective baghouses) to measure PM2.5 emissions. For each of the two emission units, RM201A testing reported PM2.5 emissions much less than the emission factor in the 2019 permit. Both the emission factors and emission limits for these two emission units were reduced in a March 18, 2021 revision to the minor NSR permit to reflect test results. At this time for the EU-7 units associated with LK-6 minor NSR permit, Region 10 is not requiring additional baghouse performance monitoring beyond that prescribed in the underlying minor NSR permit (i.e., monthly plant walkthrough) to assure representativeness of the PM2.5 emission factors and to assure compliance with corresponding limits.

These minor NSR monitoring permit conditions, combined and applicable here facility-wide, serve as the monitoring for several fugitive and particulate matter limits found in the permit. These minor NSR requirements were made applicable facility-wide to satisfy the requirement in 40 CFR 71.6(c)(1) to include monitoring, recordkeeping, and reporting sufficient to assure compliance with the applicable requirement. These requirements apply to emission sources that normally do not exhibit visible or fugitive emissions. If the Permittee prefers a specific monitoring approach for any emission sources subject to this requirement, the Permittee can propose a new approach as a permit modification. See Permit Condition 4.14 for emission units that are exempted from these requirements.

Permit Condition 4.14 states that the monthly plant walkthrough requirement is not applicable to PB-1, PB-2, and IC-1 through IC-11. The monthly walkthrough requirement is also not applicable to visible emissions exhausted from veneer dryer heating section bypass stacks. See unit-specific sections for monitoring determinations for these emission generating activities.

Permit Conditions 4.15 and 4.16 have been included in the permit because a December 2002 change to the PSD regulation applicability test for modifications resulted in a new applicable requirement for PSD major sources. 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 requirement will be relevant to the facility only when the Permittee is contemplating making physical or operational changes to the facility. In those instances, Region 10 recommends that the Permittee contact the Region to discuss their plans and verify their assumptions.

Permit Conditions 4.17 through 4.22 contain requirements from Permit No. R10TNSR01803 and R10PSD00103. See permit analysis for Permit No. R10TNSR01803 and fact sheet for Permit No. R10PSD00103 for further detail.

Permit Conditions 4.23 incorporates FARR requirements by reference into the permit. See Appendix B to this statement of basis for details.

Permit Section 5 – Unit-Specific Requirements for EU-1 – CE Boiler (PB-1) and Riley Boiler (PB-2)

Permit Condition 5.1 limits the PM emissions from the boiler to 0.2 gr/dscf at 7% O_2 and describes the method for determining compliance. The limit applies at all times. Emissions from each boiler are controlled by a multiclone and dry ESP. The FARR PM limit converts to approximately 0.4 lb/MMBtu. See Region 10's May 8, 2014 memorandum entitled, "Non-HAP Potential to Emit Emission Factors for Biomass Boilers Located in Pacific Northwest Indian Country" at https://www.epa.gov/sites/production/files/2016-09/documents/bbnonhappteef_memo.pdf for the calculation to convert the FARR PM grain loading limit into units of "lb/MMBtu."

June 2024 performance testing of each boiler operating near maximum steam generating rate (high load) indicates actual PM emissions of 0.0043 lb/MMBtu (PB-1) and 0.0107 lb/MMBtu (PB-2), well below the FARR PM limit. At low load (1/3rd of maximum steam generating capacity), PB-1 emits 0.008 lb/mmBtu (April 2022 test) while PB-2 emits 0.003 – 0.038 lb PM/MMBtu (April 2022, July 2022, April 2023 and April 2024 tests), also below the FARR PM limit. Each boiler is also subject to a more stringent NESHAP Subpart DDDDD PM emissions limit of 0.020 lb/mmBtu for PB-1 and 0.037 lb/MMBtu (0.034 lb/MMBtu on or after October 6, 2025) for PB-2. Compliance with the FARR PM limit will be assured by assuring compliance with the more stringent NESHAP PM limit.

PotlatchDeltic has indicated that it may at some point choose to no longer demonstrate compliance with the NESHAP Subpart DDDDD PM emission limit (PM is a surrogate for total select metals or "TSM") through periodic performance testing and with the corresponding visible emission and secondary ESP power operating limits/monitoring requirements. Pursuant to Permit Condition 5.32, the NESHAP DDDDD PM monitoring/testing requirements no longer apply if PotlatchDeltic chooses to demonstrate compliance with the TSM limit through some other means. Should that happen, Region 10 will consider (at that time) reopening this permit pursuant to Permit Condition 2.7 to require monitoring and testing as necessary to assure compliance with the FARR PM limit.

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

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

$$= \frac{0.00134 \times 2 \times 385 \times 1\times10^6 \times 1\times10^6}{9700 \times 8700 \times 64}$$

$$= 191 \text{ ppmdv at } 0\% \ O_2$$

where:

expected fuel S = 0.134% by weight, dry basis. Basis for value is 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 = 9700 dscf/MMBtu at 0% O_2. Value from 40 CFR 60, Appendix A, RM19, Table 19-2. 9700 dscf/MMBtu is a typical value and is from February 2015 PB-1 and PB-2 stack test and corresponding hog fuel analysis.

fuel heat content = 8700 Btu/lb, dry basis. This typical value is from February 2015 PB-1 and PB-2 hog fuel analysis.

SO_2 molar weight = 64 lb SO_2/lbm
Btu conversion = $1x10^6$ Btu per MMBtu
ppm conversion factor = $1x10^6$ parts per million parts

Using the worst-case sulfur content of bark from the cited technical journal article, and assuming all sulfur in the wood is emitted as SO_2, the concentration will be around 191 ppm at 0% O_2. The limit of 500 ppm SO_2 at 7% O_2 generally corresponds to a 1.2 lb/MMBtu emission factor. See May 8, 2014 Region 10 document entitled, "Non-HAP Potential to Emit Emission Factors for Biomass Boilers Located in Pacific Northwest Indian Country" at https://www.epa.gov/sites/production/files/2016-09/documents/bbnonhappteef_memo.pdf for calculation. The actual emissions rate forecast by AP-42 (Table 1.6-2, September 2003) is 0.025 lb/MMBtu. In other words, actual SO_2 emissions are expected to be less than 10% of the FARR limit. To demonstrate compliance with the exhaust gas SO_2 limit in Permit Condition 5.2, the Permittee must document that only wood waste fuel is used (see Permit Condition 4.5). The monitoring in Permit Condition 4.5 along with the NESHAP DDDDD fuel monitoring in Condition 5.22.5 serve as the monitoring to assure compliance with Condition 5.2.

Permit Conditions 5.3 and 5.4 establish allowable daily and annual emission limits that reflect the emission rates modeled to protect the PM2.5 NAAQS in support of minor NSR permit authorizing construction of LK-6. These permit conditions specify the emission factors (lb PM2.5/mlb steam) and daily and annual operational rates (mlb steam/hr, day, yr from Condition 5.14.1) to use in calculating daily and annual PM2.5 emissions for determining compliance. The emission factors and calculated daily and annual emissions reflect the use of multiclone and ESP required in Permit No. R10TNSR01803. See Conditions 5.14 and 5.15 for monitoring to assure representativeness of the emission factors and compliance with the emission limits.

Permit Condition 5.5 limits HCl, Hg, CO and PM emissions from PB-1 and PB-2 at all times, except startup and shutdown. PB-1's firebox is a fuel cell, and the boiler fits within NESHAP DDDDD subcategory entitled, "fuel cell designed to burn biomass/bio-based solid." PB-2's firebox is a spreader stoker, and the boiler fits within NESHAP DDDDD subcategory entitled, "stokers/sloped grate/other units designed to burn wet biomass/bio-based solid." Because the HCl and Hg limits are dependent upon fuel type and not firebox design, the HCl and Hg limits for PB-1 are the same for PB-2. Because the limits for CO and PM are dependent upon firebox design, the CO and PM limits for PB-1 are not the same for PB-2. The CO and PM limits for stokers combusting wet biomass (appearing in the permit) are different from the CO and PM limits for stokers combusting kiln dried biomass. PB-2 fits in the "stokers/sloped grate/other units designed to burn wet biomass" so long as the biomass fuel combusted in the boiler exceeds 20% moisture, wet basis, on an annual heat input basis. The NESHAP provides the Permittee the option to demonstrate compliance with the heat input-based (or as a concentration by volume for CO) or steam output-based emission limits. It is the Permittee's choice whether to demonstrate compliance with the heat input-based (or as a concentration by volume for CO) or steam output-based emission limits. On October 6, 2022 EPA revised certain NESHAP DDDDD emission limits, some of which apply to PB-1 and PB-2. Compliance with the revised limits is required beginning three years after final rule promulgation in the Federal Register. For details, see final rulemaking at https://www.govinfo.gov/content/pkg/FR-2022-10-06/pdf/2022-19612.pdf.

Permit Condition 5.6 prescribes the NESHAP DDDDD work practice standards, including startup and shutdown requirements. Although PotlatchDeltic states that it combusts only clean dry biomass during startup, the NESHAP DDDDD allows combustion of additional clean fuels, including liquid and gaseous fuels. Neither PB-1 nor PB-2, however, is physically capable of combusting liquid or gaseous fuels. The NESHAP general provisions' operation and maintenance requirements at 40 CFR 63.6(e)(1) do not apply, and neither does the requirement to develop and implement a startup, shutdown and malfunction plan at 40 CFR 63.6(e)(3). See applicability of NESHAP general provisions in Table 10 to 40 CFR 63, Subpart

DDDDD. However, PotlatchDeltic is required to develop a startup and shutdown plan for those startups during which PotlatchDeltic chooses to comply with the emission limitation using definition (2) of "startup" presented in Condition 5.5 and 40 CFR 63.7575. See 40 CFR 63.7505(e) and row 5.c.2 of Table 3 to NESHAP Subpart DDDDD.

Permit Condition 5.7 limits the boilers' (a) exhaust gas opacity, (b) exhaust gas oxygen content, and (c) steam generating rate at all times except startup, shutdown and during NESHAP DDDDD performance testing. Tracking these parameters provides a measure of the degree to which the boiler and control device are continuing to operate within the range they did while demonstrating compliance during NESHAP DDDDD performance testing. See Conditions 5.11 through 5.15, below, for a discussion of monitoring for NESHAP DDDDD CO and PM emission limits. For NESHAP DDDDD, opacity is the operating parameter associated with the PM limit, oxygen is the operating parameter associated with the CO limit, and steam generating rate is the operating parameter associated with PM, CO, HCl and Hg limits.

The opacity, oxygen and steaming rate limits presented in tables 5-5, 5-6 and 5-7 of the permit are based upon monitoring performed by PotlatchDeltic during NESHAP DDDDD performance testing between 2016 and 2024. Because the highest test run average exhaust gas visible emissions measured during performance testing was less than the default 10% opacity for each boiler, the daily block average visible emissions operating limit is 10% opacity. See Appendix C to the statement of basis for EPA's determination of operating limits to assure compliance with the applicable emission limits based upon measurements presented in the performance test reports.

Permit Condition 5.8 requires PotlatchDeltic to minimize emissions generated by PB-1 and PB-2 at all times. A similar provision in the NESHAP general provisions at 40 CFR 63.6(e)(1) is not applicable.

Permit Condition 5.9 establishes the NESHAP DDDDD HCl, Hg, PM and CO performance testing schedule for PB-1 and PB-2.

Permit Condition 5.10 establishes NESHAP DDDDD performance testing requirements. Performance testing is conducted to demonstrate compliance with the emission limits and to confirm or reestablish operating limits. The permittee is required to conduct all performance tests under such conditions as Region 10 specifies based on the representative performance of each boiler as provided in 40 CFR 63.7520(a). The conditions under which testing is to be conducted is determined upon review and approval of the Permittee's site-specific test plan. When sufficient basis exists, EPA may require testing be conducted under more than one representative steam generating rate (e.g., one test at high load and another at low load). Boiler steam generating rates required for performance testing are specified in Condition 5.10.2. To provide certainty to all stakeholders of boiler operating load requirements for performance testing applicable to PB-1 and PB-2 during the term of this title V permit, Region 10 is specifying in the title V permit that testing at both high and low load is required. The permit also defines the bounds of what constitutes high and low load during performance testing.

Beginning in 2017, testing of PB-1 and PB-2 has been required at both high and low loads. For March 2017 testing, EPA required the Permittee to perform testing of each boiler at two different unit-specific representative steaming rates (high load and low load). In its March 10, 2017 conditional approval of the Permittee's site-specific test plan Region 10 stated:

> *Potlatch provided daily average steam generating rates for the Riley Boiler and CE Boiler for the period between January 31, 2016, until December 31, 2016. This information demonstrates that the Riley Boiler and CE Boiler are routinely operated at widely different steam generating rates.*

Based upon Region 10 review of recent hourly and daily average steaming rates, PotlatchDeltic's boilers PB-1 and PB-2 continue to operate at widely different steam generating rates. Region 10 has reviewed

PB-1 steaming rates for the periods March 2019 – February 2020 (daily avg), August 2020 – July 2021 (daily avg), and March 2021 – April 2023 (hourly avg). Region 10 has reviewed PB-2 steaming rates for the periods August 2020 – July 2021 (daily avg) and March 2021 – April 2023 (hourly avg). PB-1 and PB-2 6-hour block average steam generating rates for period March 2021 – April 2023 are summarized below in Figures 5-1 and 5-2.

Figure 5-1: PB-1 Steam Generating Rate Histogram March 2021 – April 2023

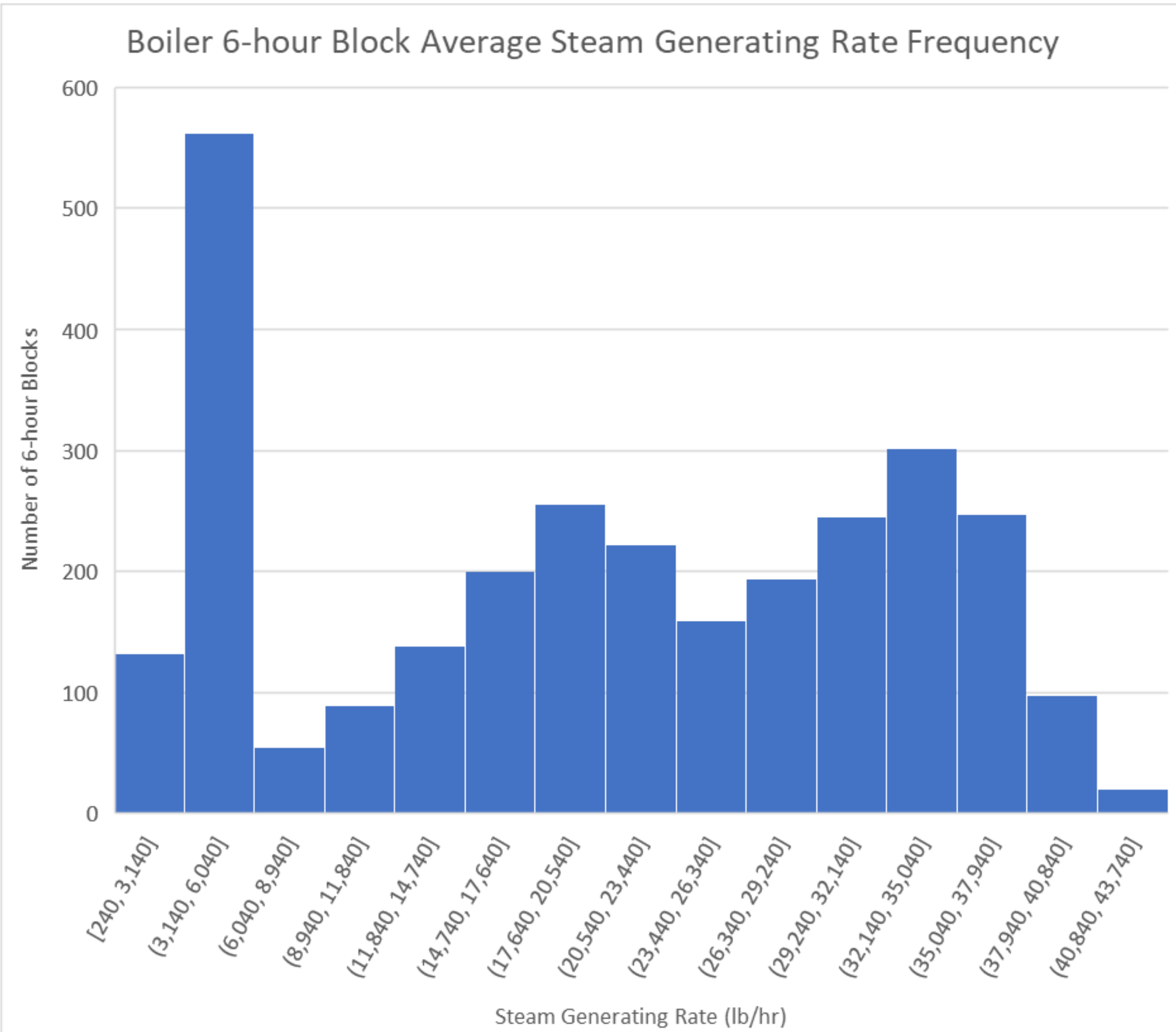
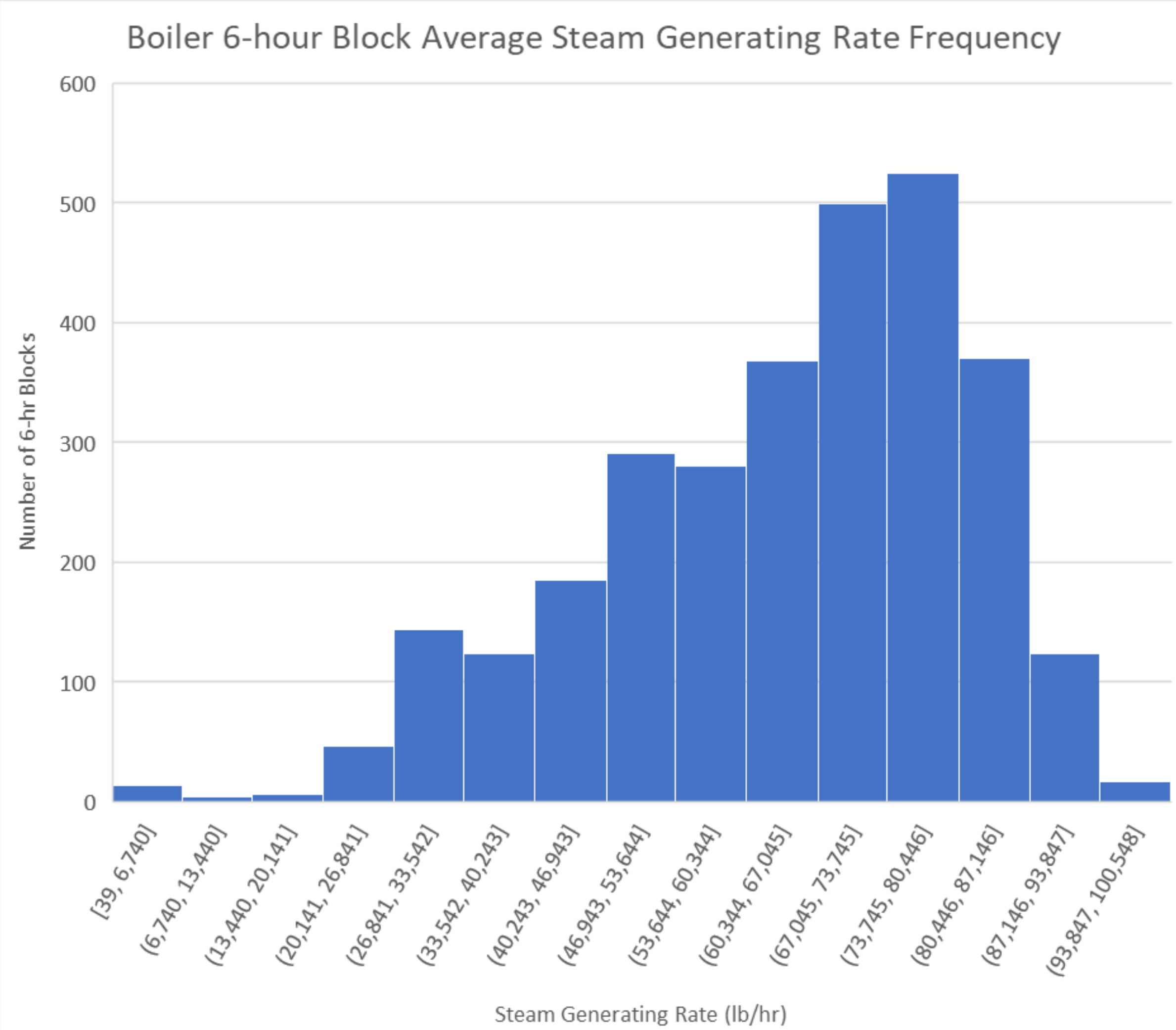


Figure 5-2: PB-2 Steam Generating Rate Histogram March 2021 – April 2023



PB-1 and PB-2 NESHAP DDDDD test results (to date) are summarized below in Tables 5-2 and 5-3. Entries in bold indicate tests during which emissions measured to be greater than 75% of the emission limit, thus triggering or continuing annual testing requirement.

Table 5-2: PB-1 NESHAP DDDDD Performance Testing Results

Test Event	Steaming Rate, lb/hr	HCl, lb/MMBtu	% of Limit	Hg, lb/MMBtu	% of Limit	PM, lb/MMBtu	% of Limit	CO, ppmdv @ 3% O_2	% of Limit
February 2016	34,311	1.89×10^{-5}	0.09	1.30×10^{-6}	22.8	0.00611	30.5	571	51.9
March 2017	24,622	1.79×10^{-5}	0.08	9.08×10^{-7}	15.8	0.00964	48.2	375	34.1
March 2017	10,010	1.89×10^{-5}	0.09	1.02×10^{-6}	17.9	0.00996	49.8	326	29.6

Test Event	Steaming Rate, lb/hr	HCl, lb/MMBtu	% of Limit	Hg, lb/MMBtu	% of Limit	PM, lb/MMBtu	% of Limit	CO, ppmdv @ 3% O_2	% of Limit
March 2019	25,388	0.0	0.0	1.1×10^{-6}	19.3	0.00233	11.7	624	56.7
March 2019	9,296	0.0	0.0	1.0×10^{-6}	17.5	0.00997	49.8	**911**	**82.8**
June 2021	33,568	2.0×10^{-5}	0.09	1.3×10^{-6}	22.8	0.011	55.0	460	41.8
April 2022	9,234	5.1×10^{-5}	0.2	1.1×10^{-6}	18.6	0.008	40.0	717	65.2
April 2023	10,731	Not applicable	-	Not applicable	-	Not applicable	-	**837**	**76.1**
April 2024	12,027	Not applicable	-	Not applicable	-	Not applicable	-	248	22.5
June 2024	33,439	1.6×10^{-5}	0.07	1.1×10^{-6}	18.5	0.0043	21.5	590	53.6

Table 5-3: PB-2 NESHAP DDDDD Performance Testing Results

Test Event	Steaming Rate, lb/hr	HCl, lb/MMBtu	% of Limit	Hg, lb/MMBtu	% of Limit	PM, lb/MMBtu	% of Limit	CO, ppmdv @ 3% O_2	% of Limit
February 2016	90,101	1.54×10^{-5}	0.07	7.80×10^{-7}	13.7	0.00359	9.7	883	58.9
March 2017	90,979	1.26×10^{-5}	0.06	7.29×10^{-7}	12.6	0.00582	15.7	629	41.9
March 2017	79,059	1.33×10^{-5}	0.06	4.95×10^{-7}	8.6	0.00473	12.8	742	49.5
March 2017	29,744	2.28×10^{-5}	0.10	1.63×10^{-6}	28.6	**0.0365**	**98.5**	299	19.9
March 2018	30,781	Not applicable	-	Not applicable	-	0.00641	17.3	Not applicable	-
March 2019	82,303	0.0	0.0	8.8×10^{-7}	15.4	0.00560	15.1	614	40.9
March 2019	33,664	0.0	0.0	9.1×10^{-7}	16.0	0.0207	55.9	200	13.3
June 2021	85,671	2.3×10^{-5}	0.10	1.2×10^{-6}	21.1	0.0048	13.0	441	29.4
April 2022	31,430	1.4×10^{-5}	0.06	1.7×10^{-6}	30	**0.0383**	**103.5**	**1,225**	**81.7**
July 2022	38,100	Not applicable	-	Not applicable	-	0.0030	8.1	Not applicable	-

Test Event	Steaming Rate, lb/hr	HCl, lb/MMBtu	% of Limit	Hg, lb/MMBtu	% of Limit	PM, lb/MMBtu	% of Limit	CO, ppmdv @ 3% O_2	% of Limit
April 2023	45,610	Not applicable	-	Not applicable	-	0.0087	23.5	**1,565**	**104.3**
May 2023	41,878	Not applicable	-	Not applicable	-	Not applicable	-	466	31.0
April 2024	44,927	Not applicable	-	Not applicable	-	0.0054	14.6	988	65.9
June 2024	82,774	$1.6x10^{-5}$	0.07	$1.6x10^{-6}$	28.7	0.0107	29.0	985	65.7

The permittee has conducted NESHAP DDDDD performance testing of the boilers several times between 2016 and 2024. Under 40 CFR 63.7520(a), performance testing must be conducted under such conditions as EPA specifies based on the representative performance of each boiler or process heater for the period being tested. EPA national stack test guidance states[11]:

> *EPA recommends that performance tests be performed under those representative (normal) conditions that:*
>
> - *represent the range of combined process and control measure conditions under which the facility expects to operate (regardless of frequency of the conditions); and*
> - *are likely to most challenge the emission control measures of the facility with regard to meeting the applicable emission standards, but without creating an unsafe condition.*

Based upon the test results, it appears that compliance with the CO and PM limits is more challenging at lower steam generating rates. The annual testing requirement has been triggered on six occasions, each based upon testing conducted while operating at a low steaming rate. See March 2019 and April 2023 CO test results for PB-1 while operating at a low (but representative) steaming rate. See March 2017, April 2022, and April 2023 PM and CO test results for PB-2 while operating at a low (but representative) steaming rate. In its 6-month Boiler MACT compliance report to EPA, PotlatchDeltic reports leaking steam tube(s) as the root cause of the relatively high CO emissions during April 2023 testing of PB-2.

Region 10 assumes that PM loading to the multiclone (pre-cleaner to ESP) is greatest at high steam generating rates because more wood and bark is fed to the boiler to supply additional heat input. Because the multiclone's effectiveness at capturing PM generally increases with rising exhaust gas velocity (associated with rising steam generating rates), it is unclear whether PM loading to the ESP increases with the steam generating rate. As stated above, it appears that compliance with CO and PM limits is more challenging at lower steam generating rates. It does not appear to be a challenge for PotlatchDeltic to comply with HCl and Hg limits given the fuel combusted by the boilers.

<u>Permit Condition 5.11</u> requires the Permittee to record the date and summary of any inspection and maintenance activity conducted on the ESP at PB-1 and PB-2. Region 10 established this additional recordkeeping consistent with 40 CFR 71.6(c)(1). The Boiler MACT contains a number of provisions intended to help assure compliance with the PM emission limits applicable to PB-1 CE boiler and PB-2 Riley boiler. This includes, but is not limited to, a requirement for good operation and maintenance of

[11] April 27, 2009 EPA memorandum entitled, "Issuance of the Clean Air Act National Stack Testing Guidance."

process equipment and emission controls at all times to minimize emissions.[12] In addition, it requires continuous monitoring of opacity as a surrogate for PM,[13] which is a surrogate for HAP metals. The Boiler MACT also establishes a daily average operating limit (outside of startup and shutdown) for opacity based on test-run average values measured during source test runs in which compliance is demonstrated.[14] Lastly, it requires continuous monitoring of steam generating rate and compliance with a source test derived 30-day rolling average steaming rate limit to assure compliance with pollutant emission limits (including PM) for which compliance is demonstrated through source testing.[15] The permit includes each of these applicable requirements.

In general, the Boiler MACT requires sources to establish control device operating parameter limits and continuously monitor control device operating parameters to assure compliance with the underlying emission limit.[16] The requirement to monitor opacity for biomass fired boilers controlled by a dry electrostatic precipitator is based on the long-understood relationship between in-stack PM concentration levels and plume opacity. Generally, the more particles (i.e., increasing concentration) that are in the stack gas, the higher the observed opacity. As discussed by Conner and Knapp, "[V]ery good mass concentration [PM] – light attenuation [opacity] relationships can be generated" even though the relationships can vary considerably from plant to plant and over time.[17] Therefore, the "information provided [from the operating parameters] can be used to ensure that air pollution control equipment is operating properly."[18]

For a useful relationship to exist between the opacity and mass concentration of the particulate emissions, size, shape, and composition of the particulates must be sufficiently constant over a useful period of time.[19] Moreover, limiting opacity of emissions has the effect of limiting their mass concentration.[20] Thus, EPA's expectation when it established continuous opacity monitoring requirements and opacity operating limits in the Boiler MACT was that boilers subject to the applicable Boiler MACT requirements would exhibit the good relationship between opacity and PM emissions that EPA has historically observed. EPA further reasoned in establishing the opacity operating limit that if there is a good relationship between opacity and PM emissions, then ensuring that opacity remains below the higher of 10% or the opacity measured during a complying source test run would be expected to assure compliance with the PM emission limit.[21]

Based on data from numerous source tests conducted at the Riley and CE boilers, we do not see this expected relationship between the opacity and PM emissions. See Figures 5-3 and 5-4 for plots of PM emissions (lb/mmBtu) versus visible emissions (% opacity) for PB-1 and PB-2, respectively. These

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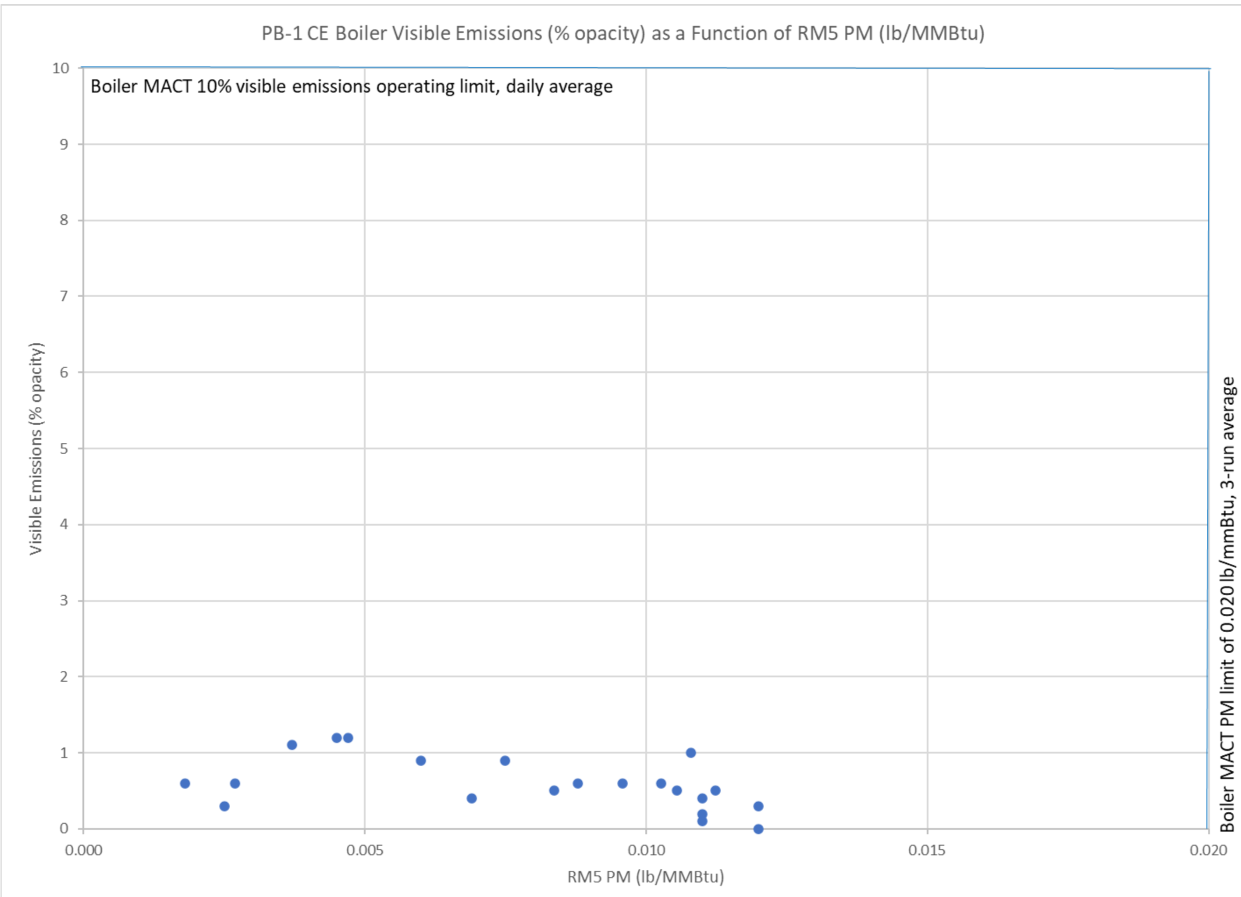
[12] See 40 CFR 63.7500(a)(3) and Condition 5.8.
[13] See 40 CFR 63.7525(c), Rows 1 to Table 8 of Boiler MACT, and Condition 5.16.
[14] See 40 CFR 63.7520(c), Rows 1.c to Table 7 of Boiler MACT and Conditions 5.7.1 and 5.10.4.1.
[15] See 40 CFR 63.7520(c), 63.7525(e), Row 5 to Table 7 and Row 10 to Table 8 of Boiler MACT, and Conditions 5.7.3, 5.10.4.3 and 5.18.
[16] See section, "How Did EPA Determine Testing and Monitoring Requirements for the Proposed Rule?" of EPA proposed rulemaking at 68 FR 1685 (January 13, 2003).
[17] William C. Conner and Kenneth T. Knapp (1988) Relationship between the Mass Concentration and Light Attenuation of Particulate Emissions from Coal-Fired Power Plants. JAPCA, 38.2, 152-157, DOI: 10.1080/08940630.1988. 10466363.
[18] EPA, op. cit. 68 FR 1685.
[19] Measurement of the Opacity and Mass Concentration of Particulate Emissions by Transmissometry. EPA –650/2-74-128. November 1974.
[20] Ibid.
[21] See section, "Opacity Is an Operating Parameter" of final EPA rulemaking available at 80 FR 72797 (November 20, 2015).

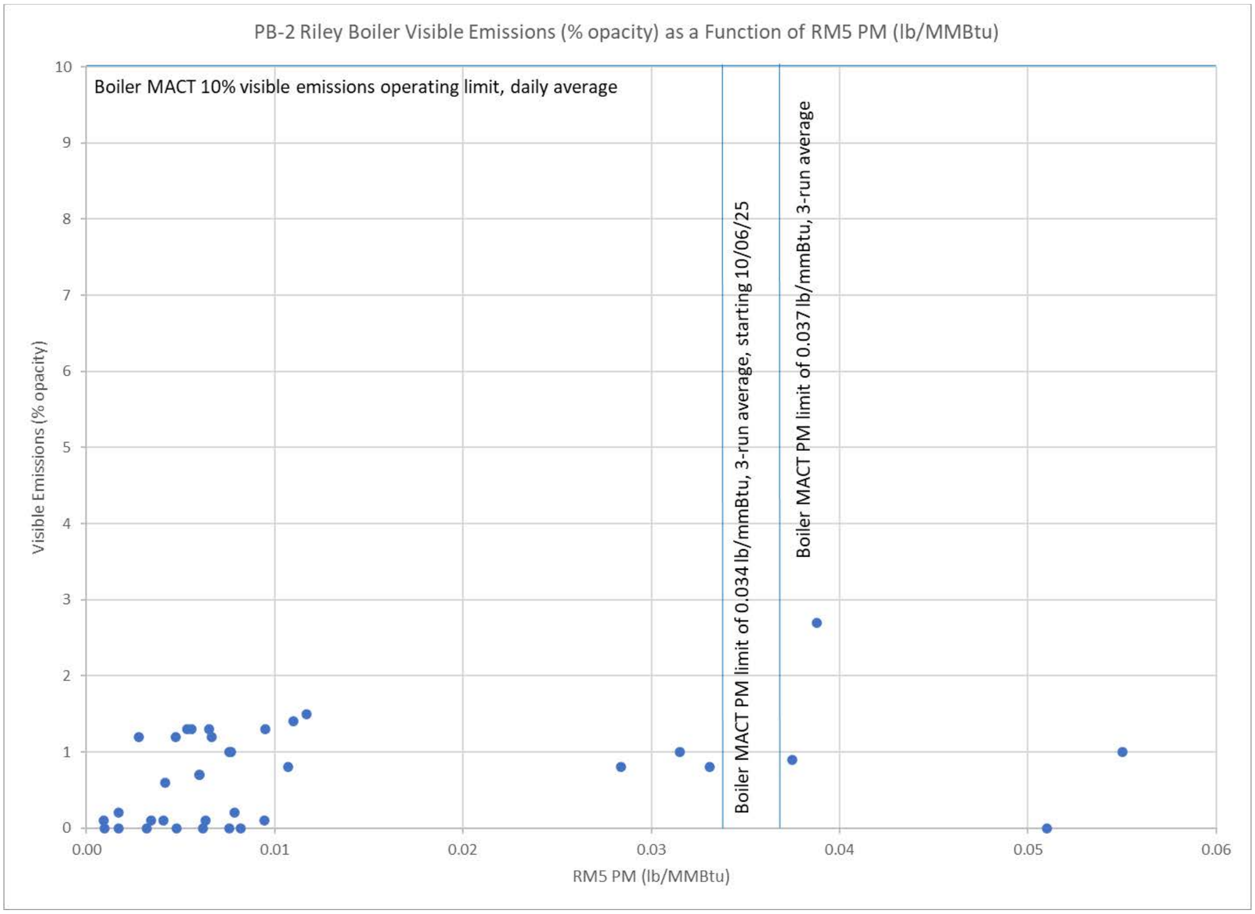
figures are excerpts from Appendix E of this SOB. For both the Riley and CE boilers, visible emission levels as measured by the COMS are consistently in the 1% to 2% opacity range regardless of the measured PM levels, even when PM levels are above the value of the PM emission limit. Visible emissions around 0.75% opacity are marginally detectable by the COMS used by PotlatchDeltic.[22] Higher PM levels do not appear to be associated with higher opacity levels at these two boilers. As such, the relationship between opacity and PM levels in these boiler stacks does not conform to the expected relationship upon which the boiler MACT opacity monitoring is based. Therefore, Region 10 is proposing additional monitoring, recordkeeping, and/or reporting as specified in Conditions 5.11, 5.12, 5.13, 5.14.4, 5.14.5 and 5.15. This additional monitoring is consistent with 40 CFR 71.6(c)(1). In addition, Region 10 will continue to use existing monitoring required by a NSR permit in Condition 5.14. The basis for each of these conditions is discussed further below.

Figure 5-3: PB-1 NESHAP DDDDD Source Test Runs – PM Emissions (lb/mmBtu) vs Opacity



[22] See document 6z in the administrative record.

Figure 5-4: PB-2 NESHAP DDDDD Source Test Runs – PM Emissions (lb/mmBtu) vs Opacity



As stated above, Condition 5.11 requires the Permittee to record the date and summary of any inspection and maintenance activity conducted on the ESP at PB-1 and PB-2. In order to comply with Conditions 5.5, 5.7, and 5.8[23] the Permittee must maintain the ESP to ensure sufficient capture efficiency. Monitoring and recording of inspection and maintenance activity will facilitate determination as to whether the ESP is being operated and maintained in a manner necessary to comply with Conditions 5.5, 5.7, and 5.8. See EPA instruction material "Lesson 6 – ESP Operation and Maintenance" in Appendix D of this SOB. Page 15 of 42 of Appendix D includes a preventive maintenance checklist for a typical fly ash precipitator. EPA published *Operation and Maintenance Manual for Electrostatic Precipitators* in September 1985. The document (EPA/625/1-85/017) is available online at https://nepis.epa.gov/Exe/ZyPDF.cgi/20008QN4.PDF?Dockey=20008QN4.PDF. See Appendix D of the document for example forms to record ESP inspection and maintenance activity.

<u>Permit Conditions 5.12 and 5.13</u> require the Permittee to conduct air-load and gas-load testing of the ESP (operating <u>without</u> automatic voltage controller engaged) to plot V-I (voltage-current) curves. Based on data specific to Permittee's ESPs, to be effective, enough voltage must be applied to the discharge

[23] Inclusion of this condition (or conditions 5.12-5.15) should not be construed as modifying or particularizing the requirements of Condition 5.8, an indication that sufficiency monitoring is necessary for good air pollution control practice provisions in all circumstances, nor limiting the types or relative probative value of information the EPA may use to determine compliance with Condition 5.8.

electrodes to generate an electric field in the ESP.[24] The strength of an electric field is measured by the flow of current across it. V-I curves reveal that no current is generated until a minimum threshold voltage is applied. Once a minimum threshold voltage is applied, additional increases in voltage result in relatively sharp increases in current. V-I curves are developed to evaluate ESP performance by comparing the graphs from inlet field to outlet field and over periods in time. Deviation from the normal or previous results can indicate that a problem exists; a problem unrelated to the AVC. Comparison of air-load curves from testing performed just before and after a field is serviced will confirm whether the maintenance work corrected the problem(s). In its ESP Operating & Maintenance Instruction Manual provided to PotlatchDeltic on pages III-5 and III-6, ESP manufacturer PPC states, “Air load and gas load meter readings enable a comparison with values established at precipitator installation and can help pinpoint performance deterioration. They should be checked during and after each outage. Meter readings taken immediately when a ‘down’ precipitator is returned to service can serve as a check on changes resulting during outage.” See also pages 11-14 of Appendix D of this SOB for further explanation of testing to develop V-I curves.

Permit Condition 5.14.
Overview

Condition 5.14 contains applicable requirements from (1) the minor NSR permit (R10TNSR01803), (2) gap-filling monitoring and recordkeeping pursuant to 40 CFR 71.6(a)(3)(i)(B) for Condition 5.1 (FARR 0.2 gr/dscf @ 7% O2 PM limit); and (3) supplemental monitoring and recordkeeping pursuant to 40 CFR 71.6(c)(1) for Conditions 5.5.5 and 5.5.6 (Boiler MACT PM emission limits) and 5.5.3 and 5.5.4 (Boiler MACT CO emission limits).

Applicable requirements from NSR Permit (R10TNSR01803)

Conditions 5.14.1 – 5.14.4, 5.14.6, and 5.14.7 of the title V permit reflects Condition 4.3 of the minor NSR permit (R10TNSR01803) authorizing construction of lumber dry kiln LK-6. The minor NSR permit includes emission limits (daily and annual) applicable to the boilers exclusively for PM2.5. The limits assure the LK-6 project does not cause or contribute to a PM2.5 NAAQS violation. In addition to having their basis in minor NSR permit R10TNSR01803, Conditions 5.14.1 through 5.14.3 are also periodic monitoring (40 CFR 71.6(a)(3)(i)(B)) for the FARR 0.2 gr/dscf @ 7% O2 PM limit. The resultant monitoring data provides Permittee with a measure of the degree to which the boiler and multiclone are continuing to operate as they did during performance testing and is useful for troubleshooting problems. Conditions 5.14.4 through 5.14.7 are not periodic monitoring for the FARR PM limit because Region 10 lacks sufficient information to establish that it is necessary to operate the ESP to comply with the emission limit. Conditions 5.14.4 reflects more than just the requirements in minor NSR permit R10TNSR01803’s Condition 4.3.4. The requirement has been augmented as explained below in Boiler MACT supplemental monitoring discussion.

The requirement in Condition 5.14.1 (steam monitoring) is similar to the NESHAP DDDDD requirement in Condition 5.18. As explained further below, steam monitoring is also necessary to implement a requirement that the Permittee respond to excursions defined by PB-1 steaming rate-specific ESP secondary voltage falling below minimum thresholds in Condition 5.15.1.

The requirement in Condition 5.14.2 (O2 monitoring) is similar to the NESHAP DDDDD requirement in Condition 5.17. Compliance with O2 operating limits (Conditions 5.5.3 and 5.5.4) is intended to assure compliance only with the Boiler MACT’s CO limit, not the PM limits (which is a surrogate for metal HAP). Condition 5.14.2, however, is periodic monitoring for Boiler MACT PM limits in Conditions 5.5.5 and 5.5.6 just as it is for FARR PM limits.

[24] *Id.* These conditions have been included based on data specific to PB-1 and PB-2 and are not necessarily reflective of monitoring needed at all boilers with ESPs.

Condition 5.14.3 (multiclone monitoring) requires the permittee to measure continuously and record hourly pressure drop across the multiclone. In addition to having its basis in the minor NSR Permit, this condition is periodic monitoring for the Boiler MACT PM limits in Conditions 5.5.5 and 5.5.6. This condition is useful for troubleshooting problems and provides Permittee with a measure of the degree to which the multiclone is continuing to operate as it did during performance testing and during 26-month period March 2021 to April 2023 during which ESP excursion thresholds in Condition 5.15 were established as explained further below.

Supplemental Monitoring and Recordkeeping for Boiler MACT PM Emission Limit

Condition 5.14.4 requires calculation of daily (not just hourly) averages for ESP field-specific secondary voltage and current to enable Permittee to detect excursions (abnormal or unusual manner of ESP operation defined in Conditions 5.15.1, 5.15.2 and 5.15.3) that may prompt a response to assure compliance with Boiler MACT PM limits applicable to PB-1 and PB-2.

Condition 5.14.5 requires calculation of the difference in daily ESP secondary current between contiguous fields to enable Permittee to detect excursions as defined in Condition 5.15.3 to similarly assure compliance with Boiler MACT PM limits.

As discussed under Condition 5.11, above, the additional monitoring required in Conditions 5.14.4 and 5.14.5 have been added based on Region 10's analysis of boilers PB-1 and PB-2. Conditions 5.14.4 and 5.14.5 are necessary to enable Permittee to compare the ESP parameters to the excursion thresholds in Condition 5.15, below. See full discussion of the basis for Condition 5.15, below.

Secondary voltage and current are key ESP performance parameters. Accordingly, these conditions require the Permittee to monitor and record these parameters. Permittee may use these records to perform intermittent evaluations of ESP performance and detect problems contributing to excess emissions between source tests. Thus, the monitoring and recordkeeping requirements in these conditions contribute to assuring compliance with Boiler MACT PM limits at PB-1 and PB-2.

Supplemental Monitoring and Recordkeeping for Boiler MACT CO Emission Limit

Condition 5.14.8 requires monthly monitoring of carbon monoxide concentration (ppmdv corrected to 3% O2) in boiler exhaust to assist Permittee in detecting excess CO emissions. The Boiler MACT contains a number of provisions intended to help assure compliance with the CO emission limits applicable to PB-1 CE boiler and PB-2 Riley boiler. These include, but are not limited to, a requirement for periodic tune-ups (work practice for volatile organic HAP),[25] and a requirement for good operation and maintenance of process equipment and emission controls at all times to minimize emissions.[26] In addition, it requires continuous monitoring of O2 as a surrogate for CO,[27] which is a surrogate for volatile organic HAP. In addition, the Boiler MACT establishes 30-day rolling average operating limits (outside of startup and shutdown) for O2 based on test-run average values measured during source tests in which compliance is demonstrated.[28] Lastly, it requires continuous monitoring of steam generating rate and compliance with a source test derived 30-day rolling average steaming rate limit to assure compliance with pollutant emission limits (including CO) for which compliance is demonstrated through source testing.[29] The permit includes each of these applicable requirements.

[25] See 40 CFR 63.7500(a)(10), 63.7515(d), Row 3 to Table 3 to Boiler MACT, and Conditions 5.6.1 and 5.6.4.
[26] See 40 CFR 63.7500(a)(3) and Condition 5.8.
[27] See 40 CFR 63.7525(a), Row 9 to Table 8 to Boiler MACT, and Condition 5.17.
[28] See 40 CFR 63.7520(c), Row 4 to Table 7 of Boiler MACT and Conditions 5.7.2 and 5.10.4.2.
[29] See 40 CFR 63.7520(c), 63.7525(e), Row 5 to Table 7 and Row 10 to Table 8 of Boiler MACT, and Conditions 5.7.3, 5.10.4.3 and 5.18.

The requirement in the Boiler MACT to monitor boiler exhaust O2 levels[30] is based on basic principles of combustion. To achieve complete combustion and to minimize the emissions of uncombusted material (e.g., carbon in the fuel partially combusts to CO which fully combusts to CO2), sufficient O2 is necessary in the combustion chamber. Typically, this is accomplished by providing excess air to the combustion chamber such that there is more than enough oxygen for complete combustion. While complete combustion is not possible, meaning that some uncombusted CO remains, in general the higher the flue gas O2 levels, the lower the CO levels will be. CO is an indicator of fuel combustion completeness; moreover, for a boiler, minimizing CO results in minimizing organic emissions.[31] Based on these principles, monitoring O2 and setting a minimum O2 operating limit ensures complete (or as near to complete as is practicably achievable) combustion and compliance with the CO emission limit. Too much excess air, however, can reduce the combustion efficiency through several mechanisms, such as lowering combustion temperature and decreasing residence time, thereby increasing CO emissions while also increasing O2 levels.

In the case of Riley and CE boilers, when operating at low loads, we do not see the expected relationship between CO and boiler flue gas O2 concentrations for properly operated and maintained boilers. Rather than CO levels decreasing when O2 levels increase, we see the opposite – as O2 levels increase, so do CO levels. Figures 5-5 (PB-1, low steam generating rates), 5-6 (PB-1, high steam generating rates), 5-7 (PB-2, low steam generating rates), 5-8 (PB-2, low steam generating rates before and after 2020), and 5-9 (PB-2, high steam generating rates) reflect results of individual source test runs (1 or 2-hour duration each) presented in Appendix E to this SOB. As reflected in the plots, less variable and generally lower CO concentrations are observed under high load conditions. As indicated by the plotted trendlines, CO emissions are generally predicted to increase with increasing levels of O2 at low steam generating rates for which testing was conducted. NESHAP DDDDD establishes no maximum operating limit for O2, only a minimum O2 operating limit.

[30] See section, "Continuous Compliance," of final EPA rulemaking available at 75 FR 15618 (March 21, 2011) for decisionmaking to allow O2 monitoring in lieu of CO monitoring.
[31] See page 24 of the July 2022 Summary of Public Comments and EPA's Responses National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters; Amendments, which is available at docket number EPA-HQ-OAR-2002-0058-4179 at www.regulations.gov.

Figure 5-5: PB-1 NESHAP DDDDD Source Test Runs at Low Steam Generating Rates between 9,042 & 13,671 lb/hr – CO vs O2

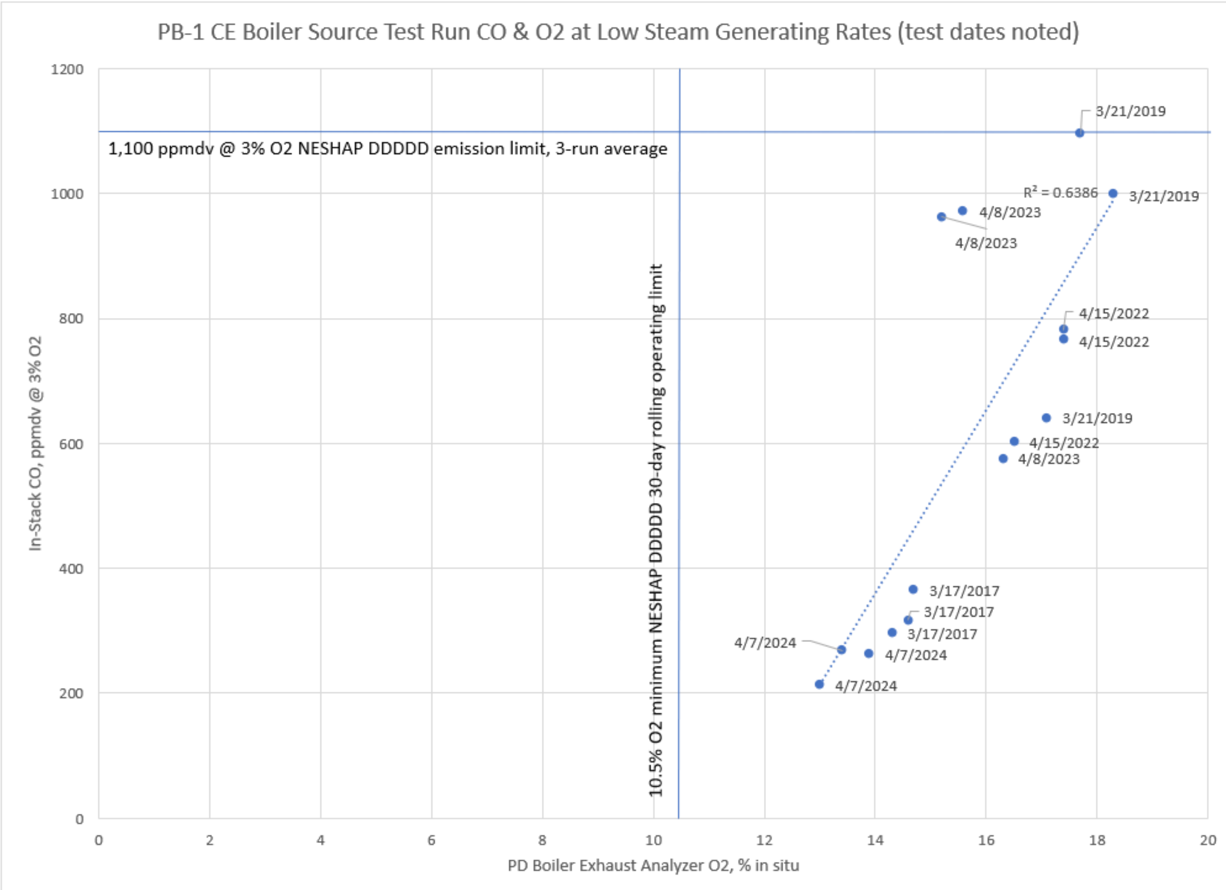


Figure 5-6: PB-1 NESHAP DDDDD Source Test Runs at High Steam Generating Rates between 24,457 & 35,079 lb/hr – CO vs O2

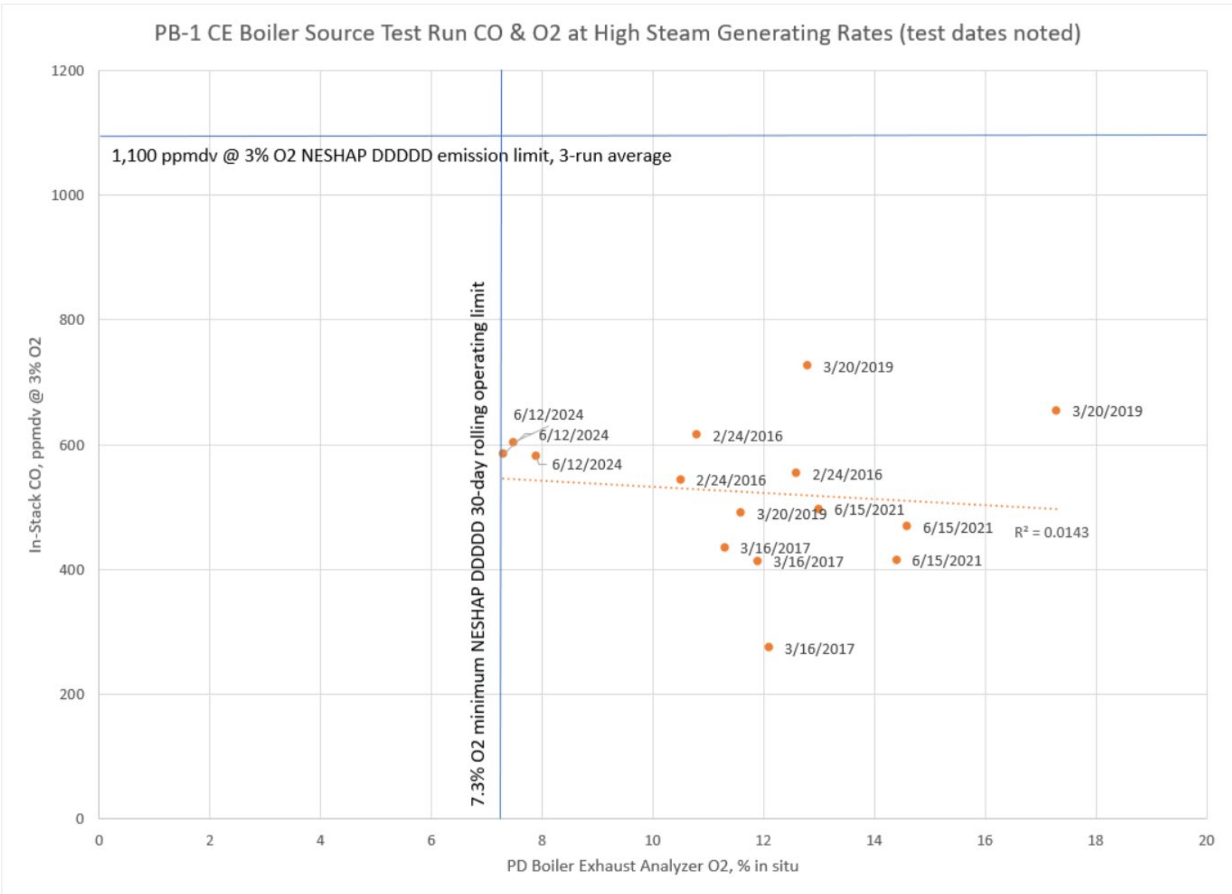


Figure 5-7: PB-2 NESHAP DDDDD Source Test Runs at Low Steam Generating Rates between 29,528 & 47,581 lb/hr – CO vs O2

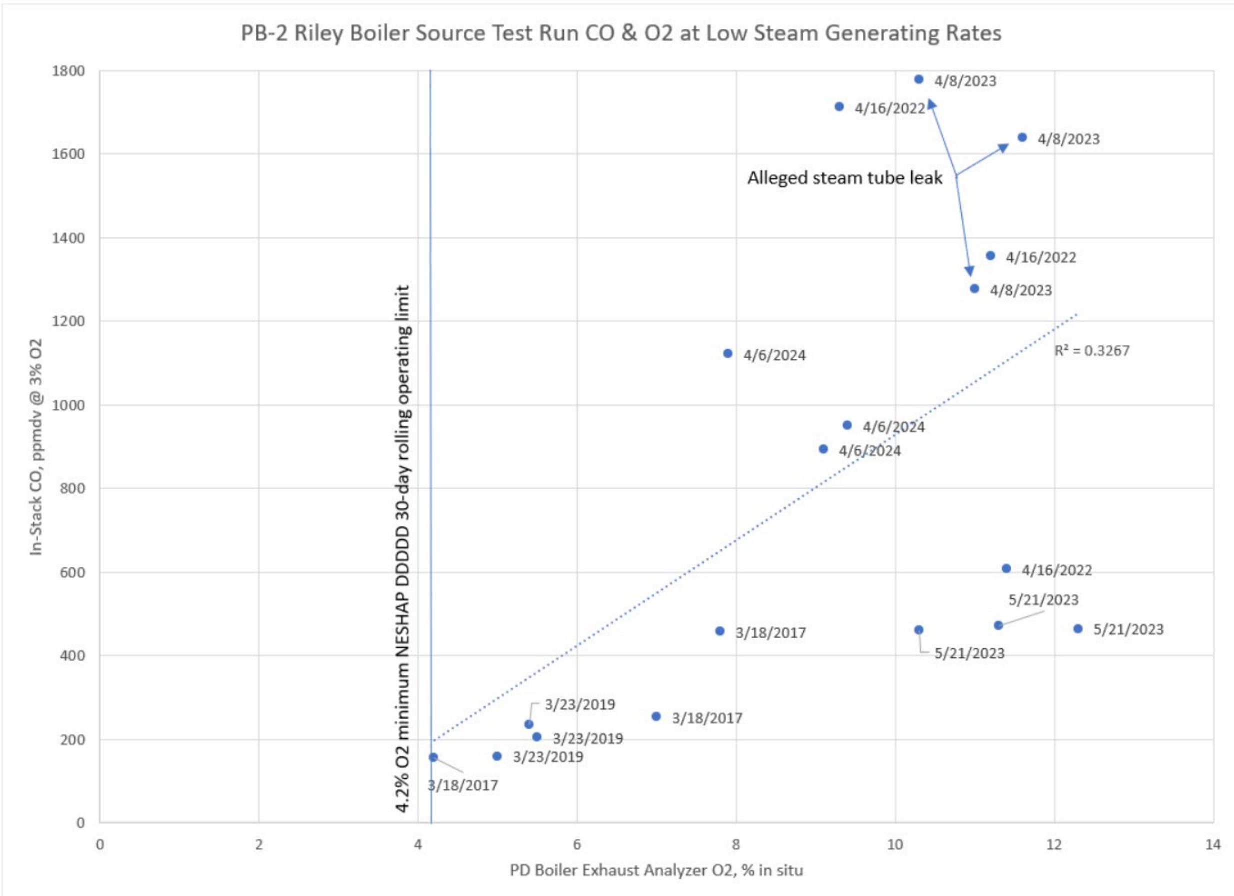


Figure 5-8: PB-2 NESHAP DDDDD Source Test Runs at Low Steam Generating Rates between 29,528 & 47,581 lb/hr – CO vs O2 (pre & post-2020)

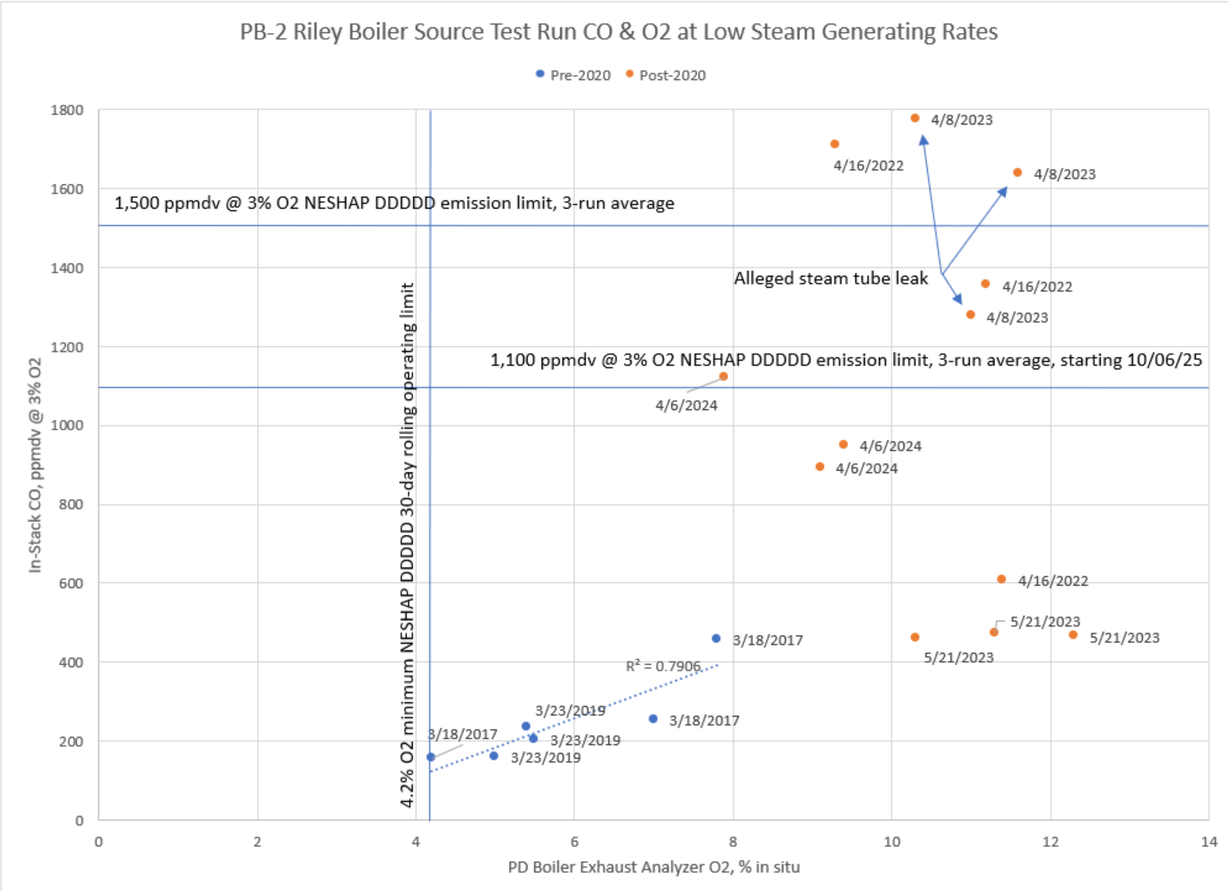
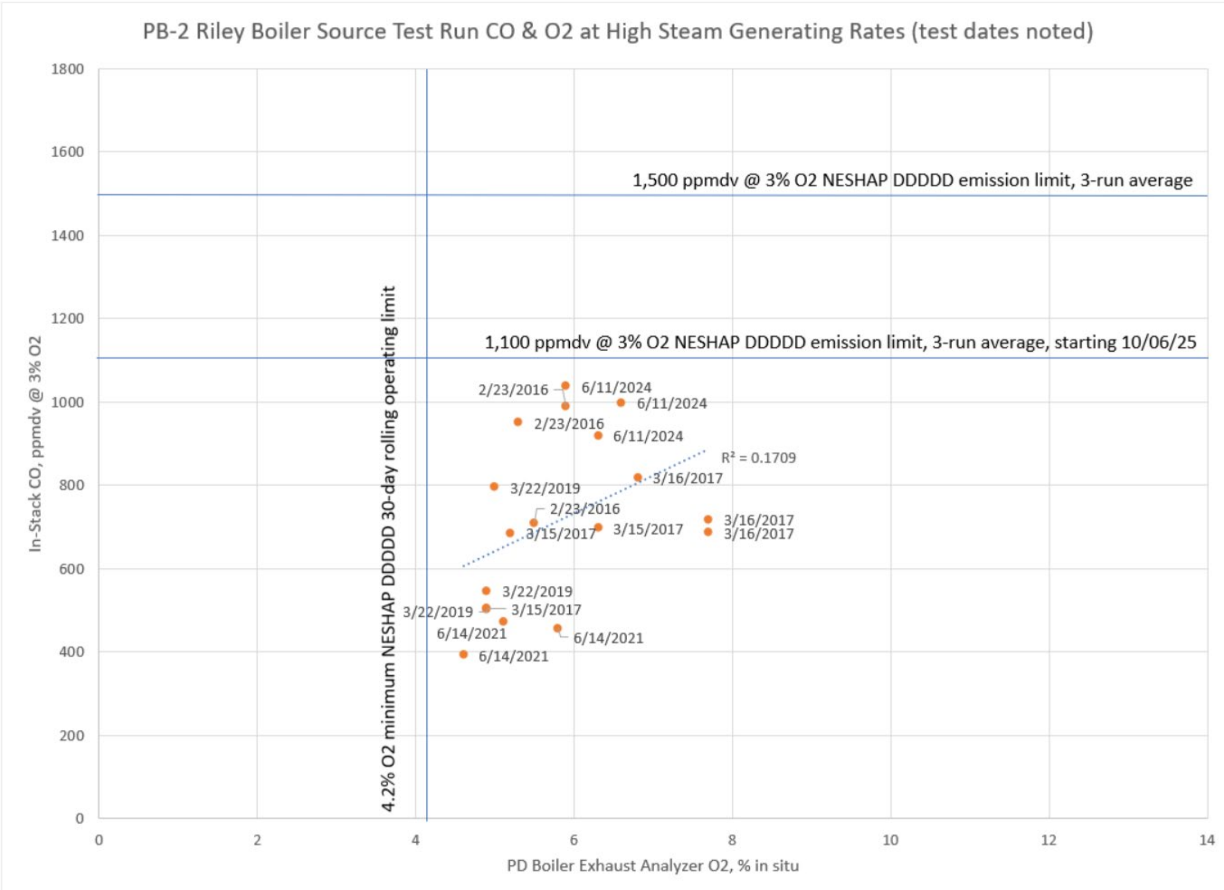


Figure 5-9: PB-2 NESHAP DDDDD Source Test Runs at High Steam Generating Rates between 78,435 & 90,990 lb/hr – CO vs O2



In addition, Boiler PB-2 experienced an exceedance of the applicable Boiler MACT CO limit during an April 2023 source test. CO emissions of 1,565 ppmdv @ 3% O2 were measured during the test, and a 1,500 ppmdv @ 3% O2 limit applies through October 5, 2025 (1,100 ppmdv @ 3% O2 beginning October 5, 2025). Based on an analysis of the PB-2 source test data, exhaust gas O2 measured during the test was around 11%, more than double the 4.2% O2 minimum operating limit specified in Condition 5.7.2 intended to assure compliance with Boiler MACT CO limit. The Permittee indicates that the April 2023 exceedance is attributable to a boiler tube leak (specific location of the alleged leak unknown to Region 10). Although the Permittee indicates that it implements boiler tube monitoring and maintenance practices considered industry standard for wood-fired boilers[32], this program failed to detect the alleged leak. Rather, the alleged leak was detected because of measuring CO emissions in excess of the emission limit. Therefore, Region 10 is proposing additional monitoring as specified in Condition 5.14.8. As stated above, Condition 5.14.8 requires monthly monitoring of CO concentration (ppmdv corrected to 3% O2) in boiler exhaust to assist Permittee to detect excess CO emissions.

Condition 5.14.8 requires permittee to measure exhaust gas CO concentration (ppmdv corrected to 3% O2) once a month. Reporting CO without correcting to a standard (i.e., 3% O2) may not be sufficient to detect a steam leak or some other operating condition that increases CO emissions. A steam leak or some other condition that increases CO emissions could be masked by increasing the volume of combustion air introduced to the fire box to reduce the uncorrected concentration of CO. CO ppmdv @ 3% O2 is determined by measuring CO concentration (ppm dry) and O2 concentration (% dry).

Region 10 anticipates the Permittee using a portable emissions analyzer to comply with Condition 5.14.8. The specific emissions analyzer selected by the Permittee (and subsequent replacement analyzer, if applicable) must be approved of in advance by Region 10. As a start in selecting an analyzer, Region 10 recommends the Permittee review the list of portable NOx/CO analyzers approved by Santa Barbara County Air Pollution Control District. The list is maintained at https://www.ourair.org/portable-analyzers/#data-table. Note, however, that the list was last updated in September 2019.

Because CO emissions can fluctuate minute-by-minute based on Region 10's review of source test results for PB-1 and PB-2, the Permittee is required to measure CO concentration (and O2 content) for at least 60 consecutive minutes each month. Because compliance with the CO limits appears to be more challenging at lower steam generating rates as discussed above in explanation of Condition 5.10, the Permittee is required to measure CO concentration (and O2 content) at low steam generating rates at least every other month. For those months during which CO performance testing is conducted, monthly monitoring must be performed simultaneous with performance testing for the entire duration of performance testing (180 minutes if three 60-minutes runs are performed, 360 minutes if three 120-minute runs are performed). Comparing simultaneous measurement results (monthly monitoring vs performance testing) enables an assessment of the degree to which monthly monitoring generates measurements similar to measurements that would have been generated by a performance test conducted in accordance with EPA reference methods.

Monthly CO (with O2 to apply correction) measurements are different from annual or every-three-year compliance demonstrations even though measurements of the pollutant are being performed in each case.

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[32] According to the Permittee, "Boiler operators are continuously monitoring several boiler operating parameters, including: steam production, boiler steam drum level, operating temperatures, boiler make-up water, etc. If there is possible boiler tube leak (identifiable due to difficulty maintaining the boiler steam drum level and steam pressure), the boilers are shutdown for inspection and necessary repairs. PotlatchDeltic has a maintenance program for the boilers where the boiler tubes are periodically checked for thickness. If boiler tube leaks are suspected but not visually identifiable, PotlatchDeltic may employ the use of a third party to do hydrostatic or ultrasound testing of the suspected tubes to confirm leaks and/or wall thickness." See document 6tt in the administrative record.

The monthly measurement is not required to adhere to the EPA reference methods listed in Table 5-8 of the permit with the exception of determining the number and location of sampling points as specified in Reference Methods 3A (for O2) and 10 (for CO). Both of those methods refer to Section 8.1.2 of Reference Method 7E. In general, the measurements recorded by the portable emissions analyzer are considered *credible evidence* (see Condition 2.6) for the purpose of determining compliance with Conditions 5.5.3, 5.5.4 and 5.8.

Permit Condition 5.15. As an extension of the monitoring in Condition 5.14, Condition 5.15 includes excursion thresholds for ESP field-specific secondary voltage and current and associated recordkeeping and reporting. Region 10 is establishing this additional monitoring for the same reasons discussed in Permit Condition 5.11, above. Region 10 established this recordkeeping and reporting consistent with 40 CFR 71.6(c)(1).

Determination of ESP Field-Specific Secondary Voltage Excursion Thresholds

Pursuant to Conditions 5.15.1 and 5.15.2, an excursion is an occasion when ESP secondary voltage falls below field-specific minimum threshold values. PotlatchDeltic explained why secondary voltage is key in a July 6, 2022 communication to Region 10, which stated:

> *In an electrostatic precipitator (ESP), electric fields are established by applying a direct-current voltage across a pair of electrodes. Particulate matter suspended in the gas stream is electrically charged when it passes through the electric fields that surround the discharge electrodes. The now negatively-charged particles migrate toward grounded collection electrodes. The ESP manufacturer recommends the secondary voltage be used as the performance indicator because the secondary voltage has a direct impact on collection efficiency. The strength of the attractive force and ability of the grounded electrode to hold particles increases with voltage. The ESP automatic voltage control system is designed to constantly drive secondary voltage to the highest sustainable levels to optimize performance. A drop in secondary voltage may indicate a malfunctioning ESP field.*

The voltages applied to the discharge electrodes in a field are limited directly by transformer capacity and the maximum spark rate (sparks per minute or “spm”) set for that field by PotlatchDeltic. At any particular time, each field’s AVC is directing the delivery of as much voltage as possible without exceeding the spark rate set point. See document 6aa in the administrative record for this permit action for a description of AVC operation. The ESP, directed by the AVC, is a dynamic system. The amount of voltage delivered will depend on exhaust stream conditions entering the field and the condition of the field’s components at the time. The current (and during period March 2021 – April 2023) spark rate set points are as follows:

PB-1 – Field 1: 25 spm, Field 2: 12 spm; and
PB-2 – Field 1: 12 spm, Field 2: 12 spm, Field 3: 12 spm.

The voltages applied to the discharge electrodes vary even while the spark rate remains relatively constant at or just below the set point. Several factors contribute to this variability. Here are a few examples. On a day-to-day basis, inherent fuel variability (species of wood, moisture content, ash content, etc.) contributes to variability in particle levels in the boiler exhaust. Sparking generally increases with increasing levels of particles in the boiler exhaust, thus diminishing the ability to achieve higher voltages. The longer an ESP continues to operate before its next scheduled shutdown for maintenance, components degrade from the condition achieved at the last tune-up. For example, discharge and collection electrodes may become misaligned. As the distance between the electrodes shrinks, sparking increases as it becomes easier for the spark to jump the gap. To maintain sparking at or below the set point, voltages must decrease from the levels achieved prior to the gap shrinking.

NESHAP DDDDD largely implements a "test and set" approach to setting operating limits for units demonstrating compliance with emission limits through periodic source testing. For PB-1 and PB-2, steam generating rate, exhaust gas oxygen content, and visible emissions operating limits are set through source testing. Indicator measurements (performed during source testing) become operating limits that must be complied with between source tests. Because the ESP is a dynamic system delivering varying amounts of secondary voltage in response to fluctuating real-time conditions, it is not feasible to use a "test and set" approach to determine secondary voltage excursion thresholds that apply under a wide range of conditions. Region 10 does not encourage disengaging the AVC and manually controlling voltage (to a relatively low value for limit-setting purpose) during a source test because resultant ESP operation does not reflect normal or usual operation.

For the ESPs serving PB-1 and PB-2, it is necessary and appropriate pursuant to 40 CFR 71.6(c)(1) to set secondary voltage excursion thresholds based on an analysis of historical voltages applied (outside of startup and shutdown) between source tests that demonstrate compliance with PM limits when the ESP appears to be performing as usual. Upon detecting an excursion for the previous day's unusual operation, the Permittee can consider whether action is necessary to restore ESP operation to its normal or usual manner of operation in accordance with good air pollution control practices for minimizing emissions. An excursion is not a violation of the underlying PM emission limit, but failing to record information about an excursion is a violation of the Permit Condition 5.15. The information recorded could be (depending upon the fact-specific circumstances) credible evidence of a violation of Conditions 5.5.5, 5.5.6 and 5.8.

A 24-hour daily block averaging time is appropriate for the field-specific secondary voltage excursion threshold. The averaging time for the visible emissions operating limit in NESHAP subpart DDDDD applicable to PB-1 and PB-2 to assure compliance with the PM emission limits is 24-hour daily block. The source test duration for determining compliance with the PM limits is six hours (three two-hour test runs). In evaluating the 26 months of records of ESP operation between March 2021 and April 2023, Region 10 did not consider secondary voltages for any day in which less than six hours of secondary voltage measurements were collected. Region 10 also did not consider secondary voltage measurements during startup and shutdown because the PM emission limits in Conditions 5.5.5 and 5.5.6 do not apply during those periods.

Region 10 set the secondary voltage excursion threshold at a level below which ESP operation is unusual or not normal. As discussed above, secondary voltage is a direct indicator of ESP collection efficiency, thus, unusual downward variation of secondary voltage indicates insufficient collection efficiency. For PB-1 and PB-2, Region 10 identifies unusual ESP performance to be occurring when daily average secondary voltage falls below 99% of daily values observed between March 2021 and April 2023. Region 10 refers to this value as the 1 percentile lower confidence level or LCL 1%. See Appendices F and G of this SOB (sheet "LCL 1% Methodology" of excel workbook) for the methodology and analysis to derive LCL 1% secondary voltage excursion thresholds for PB-1 and PB-2, respectively. Secondary voltage falling below 99% of daily values indicates a statistically significant variation in ESP performance and is thus a strong indicator that ESP collection efficiency has degraded.

Over the 26-month period, PB-2 experienced three "passing" source tests measuring PM at 13, 8 and 23% of the applicable Boiler MACT PM limit. During a 7-month subset period, PB-2 experienced a "failing" source test measuring PM emissions at 104% of the applicable Boiler MACT PM limit. For the ESP outlet (3rd) field serving PB-2, seven-month period November 2, 2021 through June 4, 2022 was not used to determine a voltage excursion threshold value due to the appearance of unusual operation. Secondary voltages applied in Fields 1 and 2 during that same seven-month period were not excluded from consideration for development of excursion thresholds for those fields. Before and after the period, voltages in all three fields are somewhat similar. But during the period in question, voltages in the third field dropped noticeably with daily values falling as low as 23.6 kV. On March 25, 2022, discharge electrode support insulators in the 3rd field were replaced. On April 16, 2022, a source test measured PM emissions in excess of Boiler MACT emission limit while 3rd field voltage averaged 25.2 kV. On June 4, 2022, electrode anti-sway bar kits were installed in the 3rd field. On July 16, 2022, a source test measured PM emissions at 8% of the Boiler MACT emission limit while 3rd field voltage averaged 44.3 kV. Figure 5-10 is an excerpt from Appendix G of this SOB (sheet "2nd Volt vs Time" of excel workbook) illustrating the analysis performed by Region 10.

Figure 5-10: PB-2 ESP Daily Average Secondary Voltage March 2021 – April 2023 & Excursion Thresholds

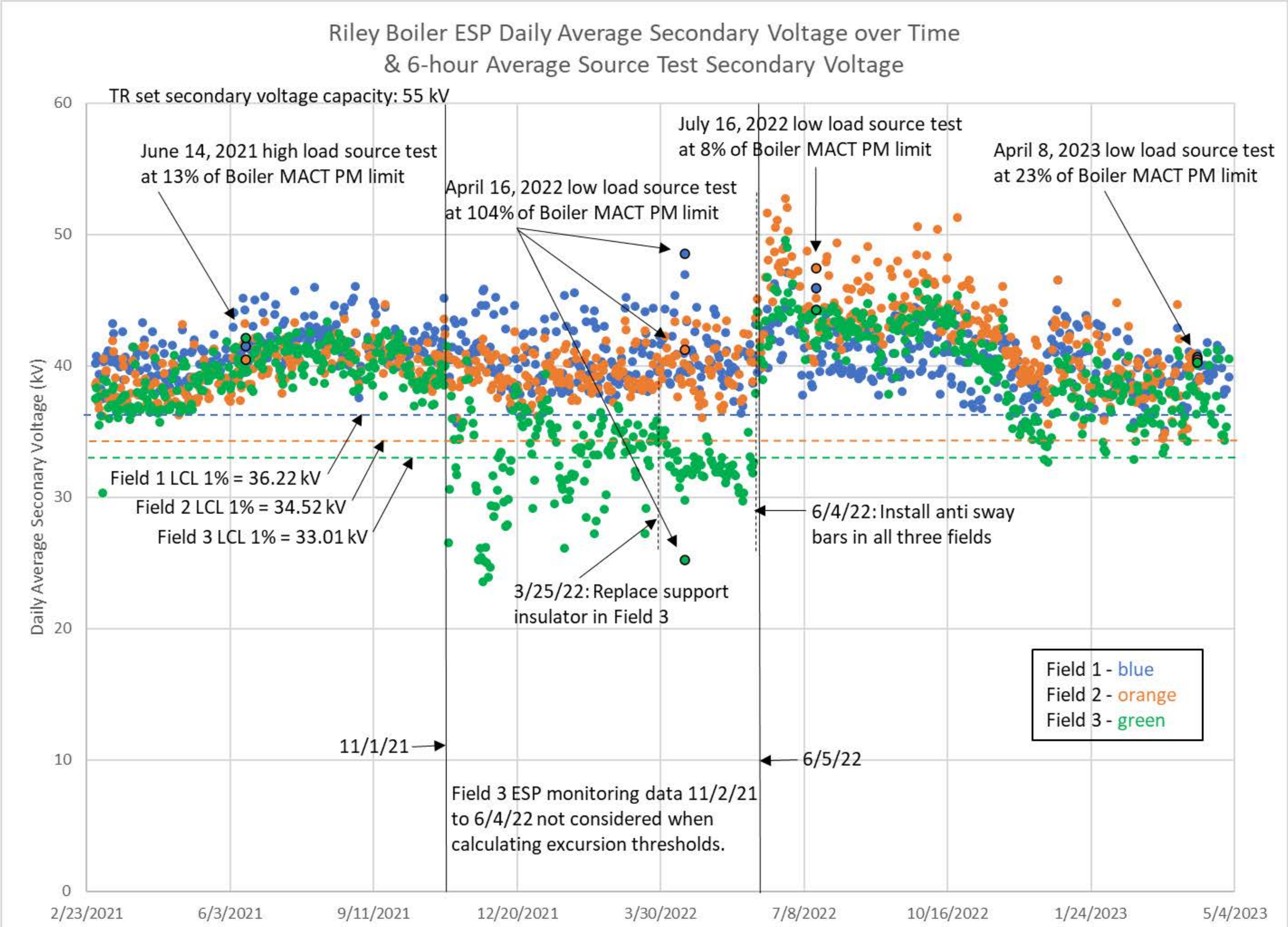


Table 5-5 summarizes PB-2 ESP field-specific secondary voltage excursion thresholds (Permit Condition 5.15.2) and accompanying “would be” excursion rates between March 2021 and April 2023, excluding November 2, 2021 through June 4, 2022 for Field 3. See sheet “Excursions Summary” of Appendix G to the SOB for more details. Region 10 does not know to what extent, if at all, PotlatchDeltic responded to any of the 12 “would be” excursions over the 26-month period. Some of these excursions may be “false positives” in which secondary voltage returns the next day to being at or above threshold levels. Had the excursion thresholds been in place prior to the 26-month period, PotlatchDeltic would likely have responded to the approximately 100 “would be” excursions by identifying and sufficiently addressing the issue(s) with Field 3 months in advance of the failed April 16, 2022 source test.

Table 5-5: PB-2 ESP Daily Average Secondary Voltage Excursion Rate March 2021 – April 2023 (excluding 11/2/21 – 6/4/22 for Field 3)

Field	Excursion Threshold (kV)	Number of Excursions March ’21 to April ‘23	Excursion Rate per Year (#/year)	Common Expression of Excursion Frequency
1	36.22	7	3.2 (7*12/26)	Just over once every four months
2	34.52	1	0.5 (1*12/26)	Once every other year
3	33.01	4 (not including 11/2/21 – 6/4/22)	2.5 (4*12/(26-7))	Almost once every four months
	Total	12	6.2	Just over once every other month

Over the 26-month period March 2021 to April 2023, PB-1 experienced two source tests measuring PM at 40 and 55% of the applicable Boiler MACT PM limit. As illustrated in Figure 5-1, the boiler is operated somewhat routinely between 3,000 and 6,000 lb/hr in the short term (6-hour blocks) generally over the weekends. Most of the time, the boiler generates steam at a rate between 20,000 and 35,000 lb/hr during the week. Figure 5-11 is an excerpt from Appendix F of this SOB (sheet “2nd Volt vs Time” of excel workbook) presenting secondary voltage over time. Figure 5-11 appears to reveal bimodal application of secondary voltage to both ESP fields. This two-tier system of applying voltage appears most distinctly beginning around June 1, 2022. The extent of secondary voltage applied to the ESP appears to be somewhat dependent upon boiler operating load. The higher the load, the greater the amount of secondary voltage applied. Figure 5-12 illustrates that secondary voltage applied to both ESP fields generally increases with the steam generating rate. Figure 5-12 is an excerpt from Appendix F of this SOB (sheet “2nd Volt vs Steam” of excel workbook). If the AVC is programmed to control the ESP differently over separate ranges of steam generating rates (Region 10 does not know if this is true), that would serve as a basis to establish different excursion thresholds for boiler operating load. Separate secondary voltage excursion thresholds have been established for daily steaming rates less than 7,500 lb/hr and daily steaming rates greater than or equal to 7,500 lb/hr. Separate thresholds are necessary to avoid establishing voltage thresholds that would unnecessarily trigger excursions simply because of boiler operating rate.

Figure 5-11: PB-1 ESP Daily Average Secondary Voltage March 2021 – April 2023

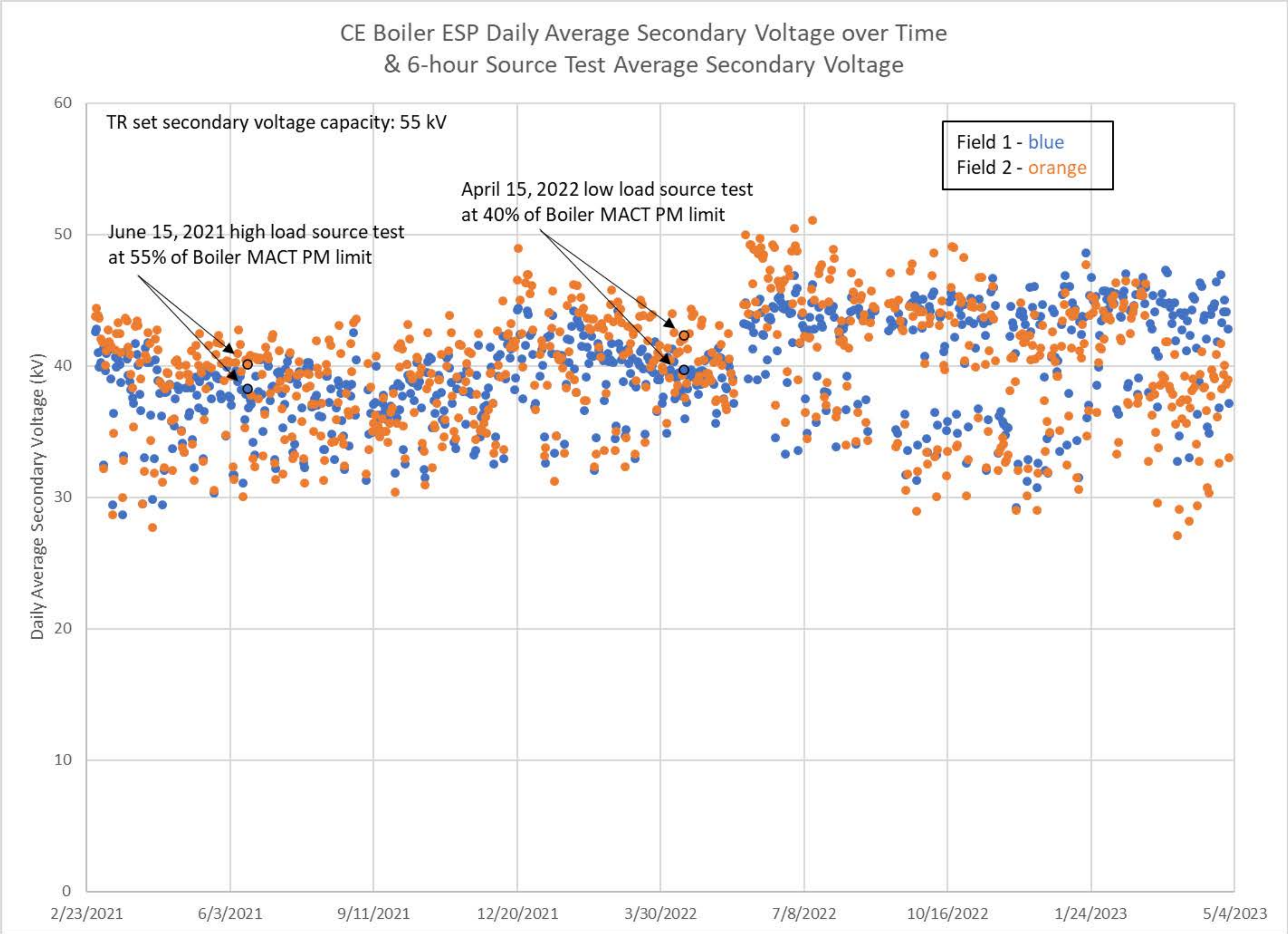


Figure 5-12: PB-1 ESP Daily Average Secondary Voltage March 2021 – April 2023 & Excursion Thresholds

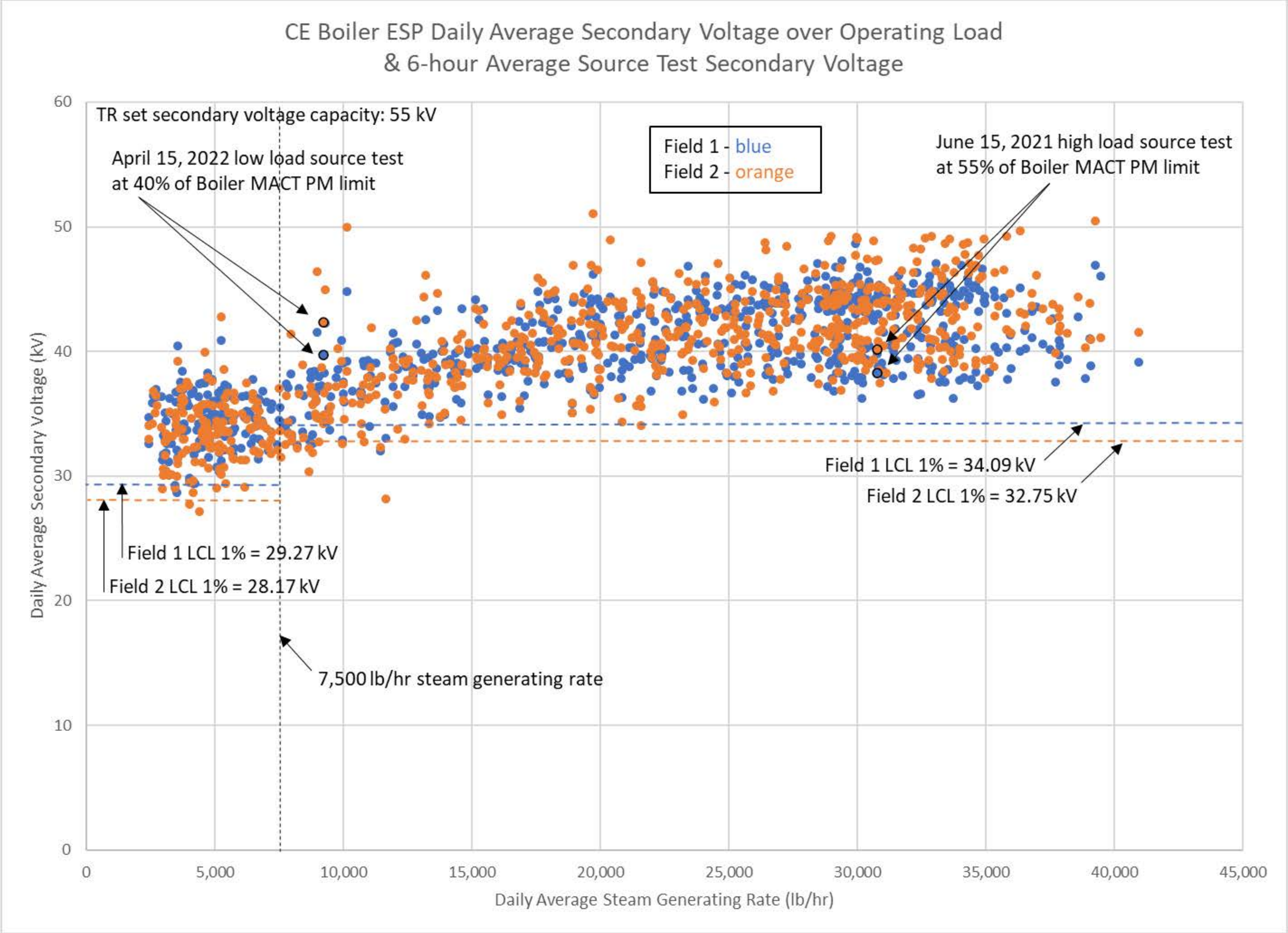


Table 5-6 summarizes PB-1 ESP field-specific secondary voltage excursion thresholds (Permit Condition 5.15.1) and accompanying "would be" excursion rates between March 2021 and April 2023. See sheet "Excursions Summary" of Appendix F to the SOB for more details. Region 10 does not know to what extent, if at all, PotlatchDeltic responded to any of the 28 "would be" excursions over the 26-month period.

Table 5-6: PB-1 ESP Daily Secondary Voltage Excursion Rate March 2021 – April 2023

Field	Steam Generating Rate (lb/hr)	Excursion Threshold (kV)	Number of Excursions March '21 to April '23	Excursion Rate per Year (#/year)	General Expression of Excursion Frequency
1	< 7,500	29.27	2	0.9 (2*12/26)	Almost once per year
	≥ 7,500	34.09	13	6.0 (13*12/26)	Once every other month
2	< 7,500	28.17	2	0.9 (2*12/26)	Almost once per year
	≥ 7,500	32.75	11	5.1 (11*12/26)	Just over once per quarter
		Total	28	12.9	Just over once per month

Either the Permittee can request, or Region 10 can initiate for cause, a revision to the ESP secondary voltage excursion thresholds in Conditions 5.15.1 and 5.15.2. Permit revisions are addressed in Conditions 2.7 and 2.8. Any substantive revision to the excursion thresholds would likely constitute a significant modification to the permit and require public review and comment to precede the change consistent with 40 CFR 71.7(e)(3).

Determination of ESP Secondary Current Excursion Threshold

Condition 5.15.3 defines an excursion as occurring if the daily block average secondary current decreases at any point from inlet to outlet fields of the ESP for three consecutive days. In general, a common trend for properly functioning ESPs is for the secondary power density ((voltage x current)/collection electrode area) to increase from inlet to outlet fields as PM (which resists current flow) is removed from the exhaust stream. It is unusual for the power density to drop at any point from inlet to outlet. See page 8 of 42 of Appendix D to this SOB and pages 237 and 238 of EPA's *Operation and Maintenance Manual for Electrostatic Precipitators*, EPA/625/1-85/017. The T/R set voltage and current capacities and collection electrode areas in the two PB-1 fields are the same, and those parameters in the three PB-2 fields are the same. Assuming spark rate set points have been established appropriately, secondary power and current should increase from inlet to outlet of the ESP. This is particularly true for the ESP receiving PB-2 exhaust because the spark rate set point is the same across all three fields (12 spm). The same or increasing amounts of secondary voltage should therefore be applied from inlet to outlet fields. PM captured on upstream fields' collection plates is removed from the boiler exhaust through rapping of plates, collection of dislodged PM into hoppers below, and finally discharge to a receptacle. The three fields are in series (one after another), not in parallel. Assuming upstream fields' collected PM is not somehow re-entrained, Field 1 removes most of the PM, Field 2 removes less, and Field 3 even less. If Field 1 removes 80% of the PM exhausted by the boiler, only 20% remains for Field 2 to remove (1*0.2=0.2). If Field 2 removes 80% of the PM it receives from the exhaust of Field 1, then Field 3 receives only a fraction of PM entering Field 1 (1*0.2*0.2=0.04). As the concentration of PM in the boiler exhaust decreases from Field 1 to Field 2 and still further from Field 2 to Field 3, secondary current conversely increases as diminishing amounts of PM offer less resistance to electron flow. See 38-minute presentation "Dry ESPs – Power Levels by Field and Particle Size" by John A. Knapik of Babcock & Wilcox Power Generation Group available online at the 17-minute mark.[33] A decrease in secondary current from one field to the next could indicate there is a mechanical problem in the downstream field that is prohibiting application of the usual amount of voltage. Perhaps the decrease stems from re-

[33] https://www.youtube.com/watch?app=desktop&v=vQ-W5Rj6M58&feature=youtu.be

entrainment of PM captured in the upstream field. The higher-than-expected concentration of PM entering the downstream field may suppress electron flow in the downstream field to the point that the current level falls below that achieved in the upstream field. The technical literature cited above does not explain how to address instances of diminishing current from upstream to downstream fields across the ESP.

Figures 5-13 (sheet "2nd Crnt vs Time") and 5-14 (sheet "2nd Crnt F1-F2 vs Time") are excerpts from Appendix F of this SOB that present PB-1 ESP daily average secondary current for Fields 1 and 2 over time. As expected, secondary current increases from Field 1 to Field 2 most of the time over the 26-month period March 2021 to April 2023.

Figure 5-13: PB-1 ESP Daily Average Secondary Current March 2021 – April 2023

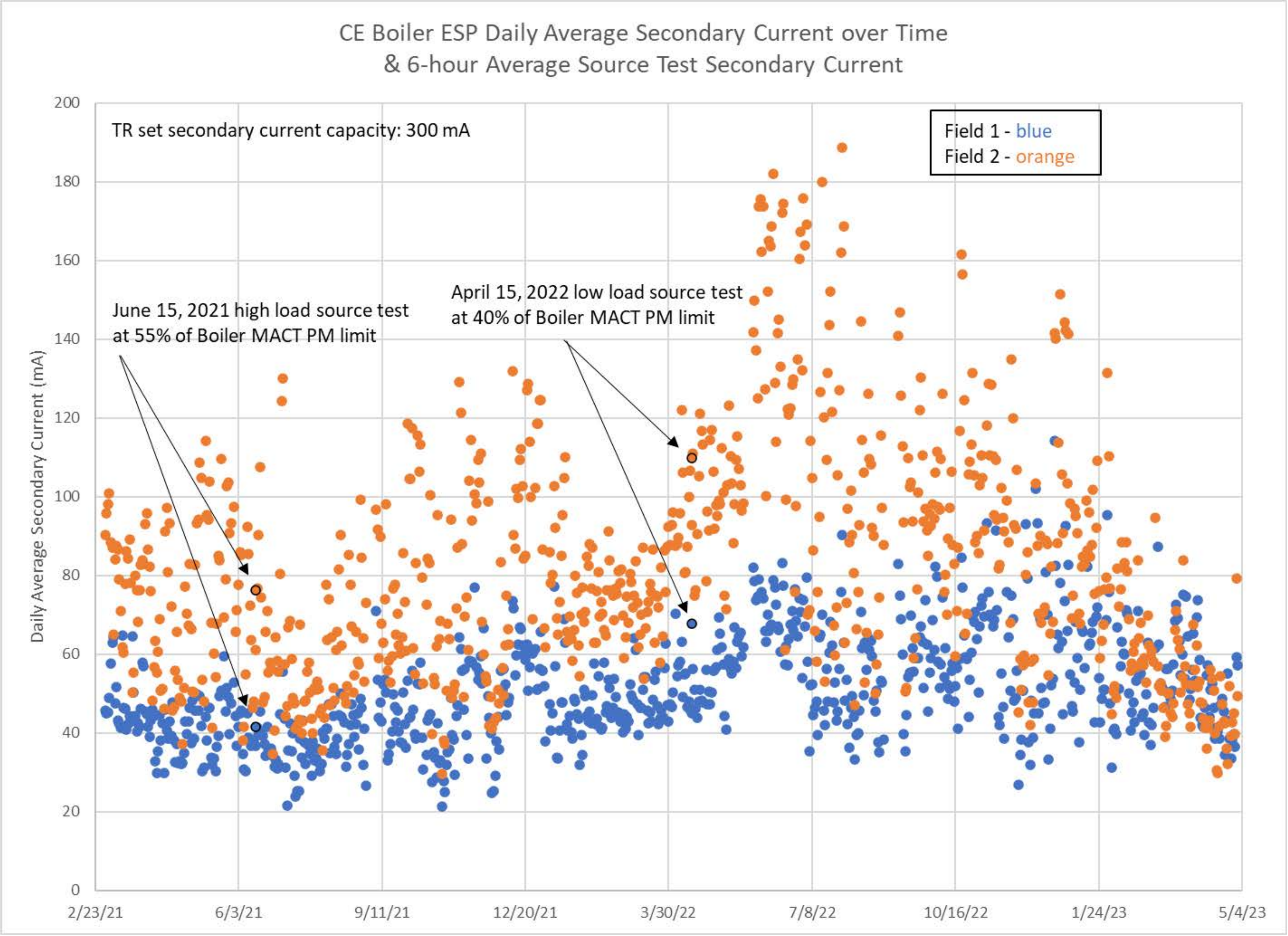
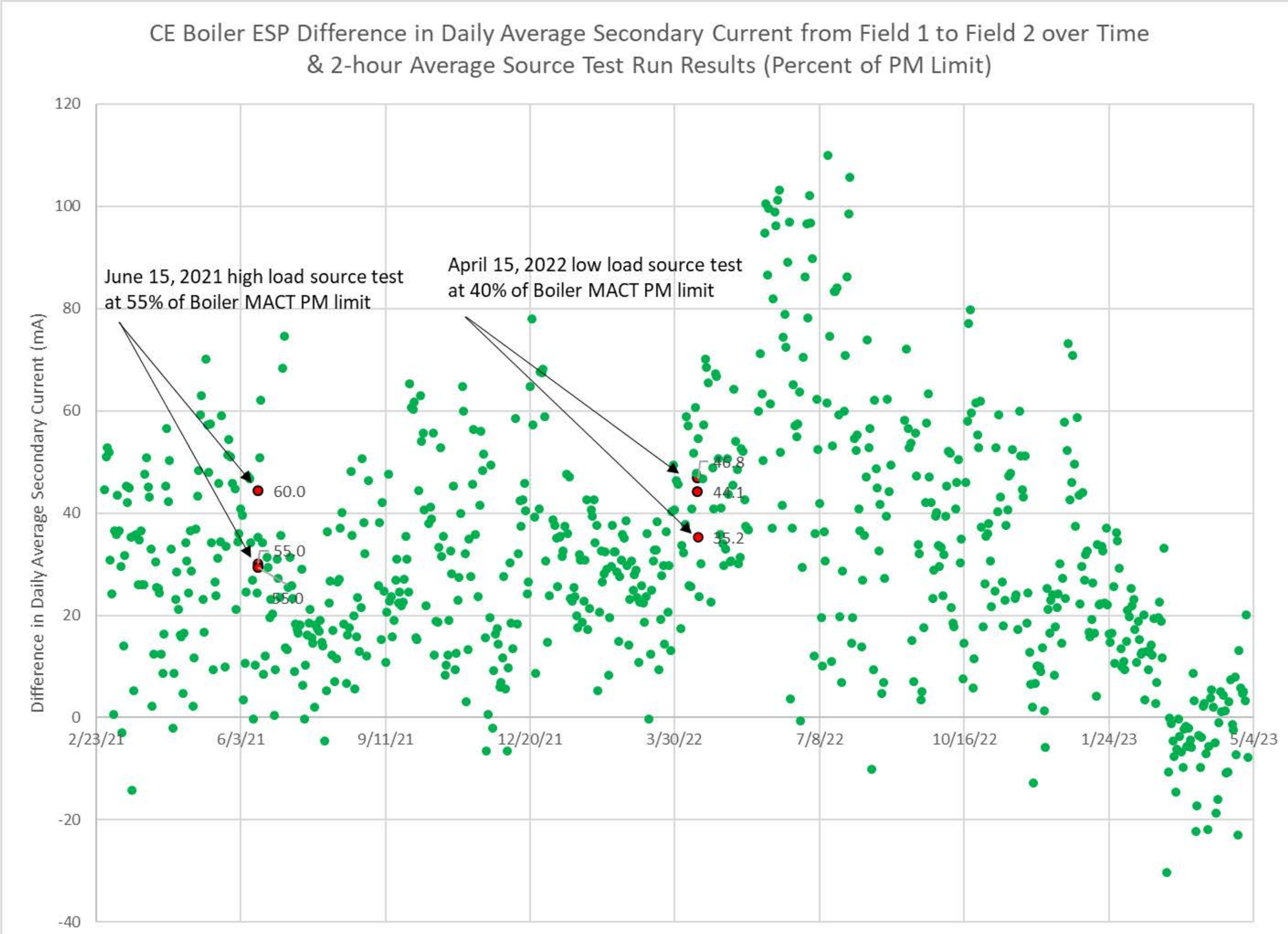


Figure 5-14: PB-1 ESP Difference in Daily Average Secondary Current from Field 1 to Field 2 March 2021 – April 2023



Fourteen instances of daily average secondary current decrease across the ESP are isolated and occur mostly on a weekend day. See SOB Appendix F's sheet "Excursions Summary." The remaining 37 of 51 instances of "current decrease" occur over periods of consecutive days within 57-day period March 5, 2023 through April 30, 2023 (final day of data analysis). The 57-day period was preceded by a boiler shutdown March 3-5, 2023 during which there was no fire in the firebox for 50 consecutive hours (see SOB Appendix F "No Fire" sheet). During the 57-day period, the boiler was shut down for approximately 9 hours on April 2, 2023 and for less than an hour on April 5, 2023. See Table 5-7 for summary of the 57-day period.

Table 5-7: PB-1 ESP Daily Average Secondary Current Decreases Field 1 to Field 2 March 5, 2023 to April 30, 2023

Secondary Current Drop Begins…	Secondary Current Drop Ends…	Duration (consecutive days)
March 5, 2023 (Sun)	March 22, 2023 (Wed)	18
March 25, 2023 (Sat)	March 29, 2023 (Wed)	5
April 1, 2023 (Fri)	April 3, 2023 (Sun)	3
April 7, 2023 (Fri)	April 10, 2023 (Mon)	4
April 15, 2023 (Sat)	April 16, 2023 (Sun)	2
April 19, 2023 (Wed)	April 20, 2023 (Thu)	2
April 22, 2023 (Sat)	April 23, 2023 (Sun)	2
April 30, 2023 (Sun)	end of data analysis period	1
	Total	37 days

Table 5-8 presents daily average secondary voltage and current information for those nine days over the 26-month period in which decrease in secondary current was accompanied by a secondary voltage excursion in Field 1 and/or Field 2. One (December 11, 2022) of the 14 isolated instances are associated with Field 2 secondary voltage excursion (Field 2 voltage too low). Five of the 37 proximate instances are associated with a Field 2 secondary voltage excursion. Neither of the two performance tests (six two-hour runs) was conducted while experiencing daily average secondary current decrease across the ESP.

Table 5-8: PB-1 Simultaneous Excursions of ESP Daily Secondary Voltage & Current Thresholds March 2021 – April 2023

Date	Daily Steam (lb/hr)	Field 1 Voltage (kV)	Excursion Threshold Minimum (kV)	Field 2 Voltage (kV)	Excursion Threshold Minimum (kV)	Field 1 Current (mA)	Field 2 Current (mA)	Δ Field 1→2 Current (mA)
Isolated Occurrences of Secondary Current Drop Across ESP								
03/20/21	3,505	**28.67**	**29.27**	30.01	28.17	64.59	50.33	**-14.3**
06/25/22	8,799	**33.34**	**34.09**	35.70	32.75	76.52	75.83	**-0.7**
12/03/22	3,440	**29.23**	**29.27**	29.04	28.17	93.05	80.31	**-12.7**
12/11/22	8,664	**32.89**	**34.09**	**32.21**	**32.75**	93.24	87.48	**-5.8**
Proximate Occurrences of Secondary Current Drop Across ESP								
03/05/23	9,036	37.97	34.09	**32.73**	**32.75**	87.33	56.97	**-30.4**
03/25/23	4,391	32.78	29.27	**27.12**	**28.17**	74.72	52.39	**-22.3**
04/02/23	11,651	**33.02**	**34.09**	**28.17**	**32.75**	73.70	51.76	**-21.9**
04/09/23	10,818	38.83	34.09	**32.73**	**32.75**	57.30	41.34	**-16.0**
04/16/23	8,671	34.87	34.09	**30.36**	**32.75**	40.45	29.82	**-10.6**

Because the remaining 45 days (out of 51 experiencing secondary current drop across the ESP) are not associated with a Field 2 secondary voltage excursion, there is value in identifying secondary current drop across the ESP as an excursion. Current drop excursions will not always be duplicative of secondary voltage excursions. An excursion is defined as three consecutive days of current drop because, based on our evaluation, this will provide an indication of abnormal operation. Over the course of the 26-month period, four episodes of at least three or more consecutive days of secondary current drop were experienced. Together, those four episodes generate 22 excursions. See Appendix F's "Excursions Summary" for details.

Figures 5-15 (sheet "2nd Crnt vs Time"), 5-16 (sheet "2nd Crnt F1-F2 vs Time") and 5-17 (sheet "2nd Crnt F2-F3 vs Time") are excerpts from Appendix G of this SOB that present PB-2 ESP daily average secondary current for Fields 1, 2 and 3 over time. With notable exception, secondary current increases from Field 1 to Field 2 and from Field 2 to Field 3 most of the time over the 26-month period March 2021 to April 2023. Current across Field 3 was less than the current across Field 2 during seven-month period November 2021 to May 2022 in which Field 3 was not operating as usual. As discussed above, a performance test during that period measured PM emissions greater than the Boiler MACT PM limit. In deriving secondary voltage threshold for Field 3, Region 10 did not consider secondary voltage operating data between November 2021 to May 2022 due to unusual operation of the field. The current across Field 3 was again less than the current across Field 2 periodically during four-month period November 2022 to March 2023. Region 10, however, did consider secondary voltage operating data November 2022 to March 2023 in deriving Field 3 secondary voltage excursion threshold because Field 3 secondary voltage during that four-month period did not fall to the extent it did in prior seven-month period and we have no other information that Field 3 was not operating as usual.

Figure 5-15: PB-2 ESP Daily Average Secondary Current March 2021 – April 2023

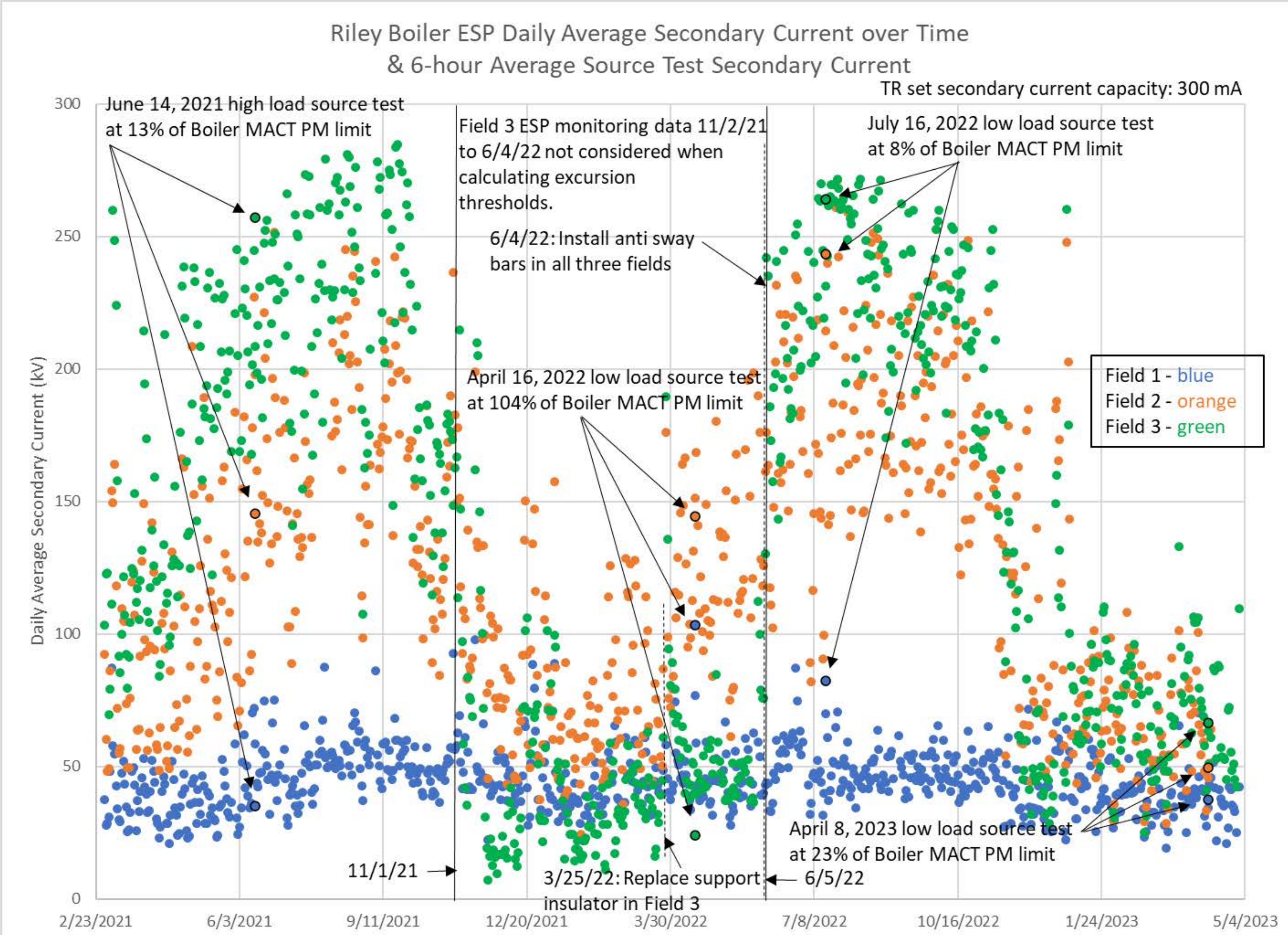


Figure 5-16: PB-2 ESP Difference in Daily Average Secondary Current from Field 1 to Field 2 March 2021 – April 2023

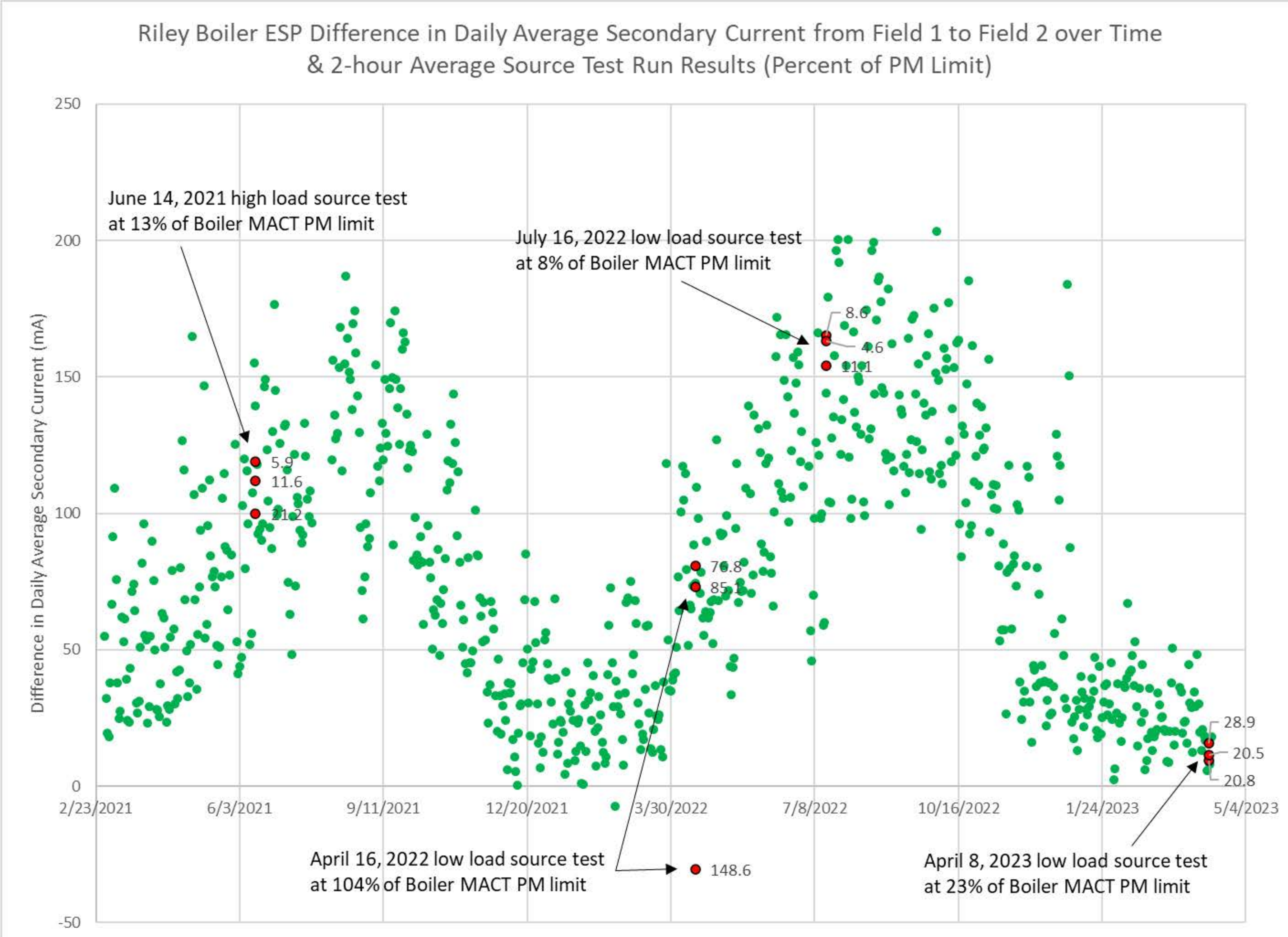
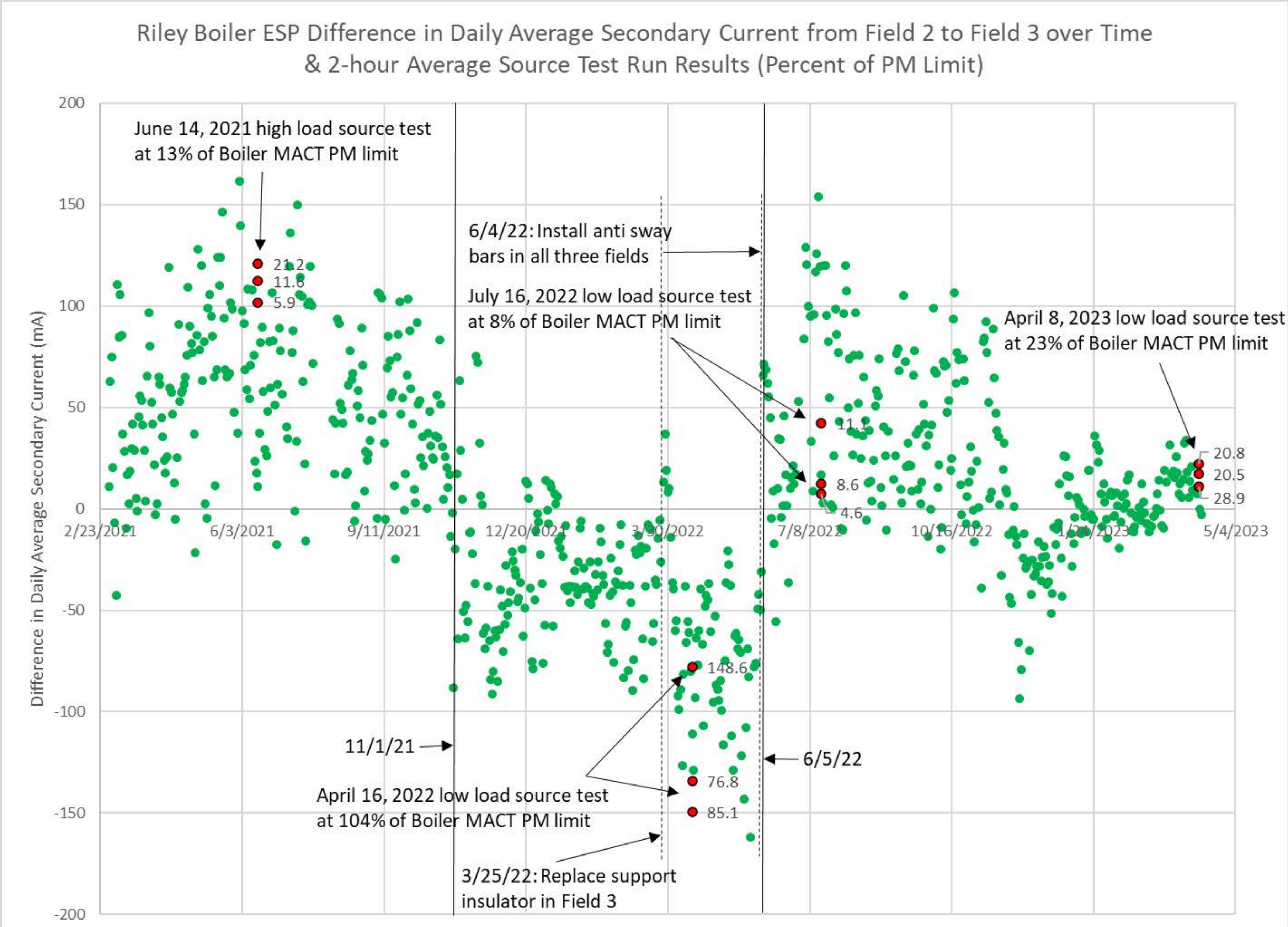


Figure 5-17: PB-2 ESP Difference in Daily Average Secondary Current from Field 2 to Field 3 March 2021 – April 2023



For the entire 26-month period, on one occasion (February 19, 2022) the secondary current across Field 2 was less than the secondary current across Field 1. That occurrence was not associated with a Field 2 secondary voltage excursion. See SOB Appendix G's sheet "Excursions Summary" for details.

In analyzing the difference between secondary current across Fields 2 and 3, Region 10 did not consider 7-month period November 2021 to May 2022 because Field 3 was not operating as usual. For the remaining 19-month period, 41 of the 116 instances of daily average secondary current decrease from Field 2 to Field 3 are mostly isolated and occur mostly on a weekend day. The exception is four-day period October 28-31, 2021. See SOB Appendix G's sheet "Excursions Summary" for details. The remaining 75 of 116 instances of "current decrease" from Field 2 to Field 3 occur over periods of consecutive days within 115-day period November 20, 2022 through March 14, 2023. The 115-day period was preceded by a boiler shutdown November 5-6, 2022 during which there was no fire in the firebox for 28 consecutive hours (see SOB Appendix G "No Fire" sheet). During the 115-day period, the boiler was not shut down. The boiler was shut down three times in relatively close proximity after the close of the 115-day period but prior to April 8, 2023 performance test. See Table 5-9 for summary of the 115-day period plus October 27 to 31, 2021.

Table 5-9: PB-2 ESP Daily Average Secondary Current Decreases Field 2 to Field 3
October 28-31, 2021 & November 20, 2022 – March 14, 2023 (Except 11/2/21 – 6/4/22)

Secondary Current Drop Begins…	Secondary Current Drop Ends…	Duration (consecutive days)
October 28, 2021 (Thu)	October 31, 2021 (Sun)	4
November 25, 2022 (Fri)	December 30, 2022 (Fri)	36
January 8, 2023 (Sun)	January 11, 2023 (Wed)	4
January 15, 2023 (Sun)	January 19, 2023 (Thu)	5
January 22, 2023 (Sun)	January 24, 2023 (Tue)	3
February 19, 2023 (Sun)	February 24, 2023 (Fri)	6
March 1, 2023 (Wed)	March 8, 2023 (Wed)	8
March 12, 2023 (Sun)	March 14, 2023 (Tue)	3
	Total	69 days

Table 5-10 presents daily average secondary voltage and current information for those six days over the 19-month (26-month period minus 11/2/21 – 6/4/22) period in which decrease in secondary current across the ESP was accompanied by a secondary voltage excursion in Field 1, Field 2 and/or Field 3. One (March 6, 2021) of the 41 isolated instances are associated with Field 3 secondary voltage excursion (Field 3 voltage too low). Three of the 116 proximate instances are associated with a Field 3 secondary voltage excursion. None of the three performance tests (nine two-hour runs outside 7-month period when Field 3 was not operating as usual) was conducted while experiencing daily average secondary current decrease across the ESP.

Table 5-10: PB-2 Simultaneous Excursions of ESP Daily Secondary Voltage & Current Thresholds March 2021 – April 2023 (Except 11/2/21 – 6/4/22)

Date	Daily Steam (lb/hr)	Field 1 Voltage (kV)	Excursion Threshold Minimum (kV)	Field 2 Voltage (kV)	Excursion Threshold Minimum (kV)	Field 3 Voltage (kV)	Excursion Threshold Minimum (kV)	Field 1 Current (mA)	Field 2 Current (mA)	Field 3 Current (mA)	Δ Field 1→2 Current (mA)	Δ Field 2→3 Current (mA)
Isolated Occurrences of Secondary Current Drop Across ESP Outside 11/20/22 – 3/14/23												
03/06/21	26,438	37.49	36.22	36.23	34.52	**30.34**	**33.01**	87.23	154.07	111.50	66.84	**-42.57**
Proximate Occurrences of Secondary Current Drop Across ESP 11/20/22 – 3/14/23												
12/07/22	82,371	**35.60**	**36.22**	38.78	34.52	35.23	33.01	34.48	78.64	49.35	44.16	**-29.29**
12/22/22	56,200	37.52	36.22	38.72	34.52	**32.89**	**33.01**	32.30	88.41	51.06	56.11	**-37.35**
12/25/22	48,649	39.80	36.22	35.59	34.52	**32.65**	**33.01**	60.79	165.53	113.89	104.74	**-51.64**
02/02/23	86,516	**36.15**	**36.22**	35.86	34.52	33.68	33.01	29.50	35.75	30.83	6.25	**-4.92**
02/23/23	88,295	**35.70**	**36.22**	35.24	34.52	**32.86**	**33.01**	23.30	29.39	25.23	6.09	**-4.16**

Because the remaining 112 days (out of 116 experiencing secondary current drop from Field 2 to Field 3) are not associated with a Field 3 secondary voltage excursion, there appears to be value in identifying secondary current drop across the ESP as an excursion. Current drop excursions will not always be duplicative of secondary voltage excursions. An excursion is defined as three consecutive days of current drop because, based on our evaluation, this will provide an indication of abnormal operation. Over the course of the 19-month period, eight episodes of at least three or more consecutive days of secondary current drop were experienced. Together, those eight episodes generate 55 excursions. See Appendix G's "Excursions Summary" for details.

Additional Basis for Supplemental Monitoring and Recordkeeping for Boiler MACT PM and CO Emission Limits

Rather than the supplemental monitoring and recordkeeping in conditions 5.11 through 5.15, Region 10 considered requiring the Permittee to install, certify, operate and maintain a continuous emission monitoring system (CEMS) to measure CO emissions (ppmdv @ 3% O2) and a CEMS to measure PM emissions (lb/mmBtu) exhausting to atmosphere generated by PB-1 and PB-2. PB-2 has been found to be emitting CO and PM emissions in excess of NESHAP DDDDD emission limits (rows 7.a & b of Table 15 to NESHAP DDDDD) on two occasions while complying (by a large margin) with the underlying regulation's operating limits intended to assure compliance with the emission limits. While the excess emissions at this boiler were measured over the duration of six-hour source tests, the excess emissions may have been ongoing for an undefined period of time undetected prior to the source tests. While PB-1 has not experienced excess emissions during performance testing like PB-2, the two boilers share a common set of circumstances to consider when assessing the degree of monitoring necessary for PB-1 to assure compliance. For example, the Permittee's boiler tube monitoring and maintenance program is common to both boilers. The lack of a correlation between visible emissions and PM emissions is common to both boilers. See Appendix E to this SOB. The ESP's serving both boilers were installed at the same time in 1995 and manufactured by same manufacturer PPC Industries. The Permittee continues to consult with PPC Industries about operation, maintenance and repair of both boilers' ESPs. Both boilers (and associated ESPs) are managed by the same organization. For PB-2, the emission limits become tighter (rows 7.a & b of Table 2 to NESHAP DDDDD) beginning October 6, 2025, but the operating limits remain unchanged. The emission limits in NESHAP DDDDD Tables 2 and 15 apply at all times, except startup and shutdown. While requiring CO and PM CEMS is within EPA's authority to require, for the following reasons EPA elected to include parametric monitoring and associated recordkeeping and reporting in Conditions 5.11 through and 5.15 to assure compliance with the CO and PM limits in NESHAP DDDDD.

The EPA has promulgated performance specifications in appendix B to 40 CFR part 60 to evaluate the acceptability of CEMS at the time of installation and soon after. EPA has promulgated quality assurance requirements in appendix F to 40 CFR part 60 to evaluate the effectiveness of quality control and quality assurance procedures and the quality of data produced by CEMS over time. For PB-2, data generated by a CO CEMS (satisfying the requirements in the regulations noted above) could be used to directly measure compliance with the 30-day rolling average 720 ppmdv @ 3% O2 CO emission limit (row 7.a of Tables 2 & 15 to NESHAP DDDDD). For PB-1, data generated by a CO CEMS (satisfying the requirements in the regulations noted above) could be used as credible evidence to determine compliance with the three-hour average 1,100 ppmdv @ 3% O2 CO emission limit (row 12.a of Tables 2 & 15 to NESHAP DDDDD). For PB-2, data generated by a PM CEMS could be used as credible evidence to determine compliance with six-hour average 0.034 and 0.037 lb/mmBtu emission limits in row 7.b of Tables 2 and 15 to NESHAP DDDDD, respectively. For PB-1, data generated by a PM CEMS could be used as credible evidence to determine compliance with the six-hour average 0.020 lb/mmBtu emission limit in row 12.b of Tables 2 and 15 to NESHAP DDDDD.

Installing, certifying, operating and maintaining CO and PM CEMS for PB-2 would be a significant undertaking for the Permittee. Region 10 assumes the Permittee does not already own either the measurement equipment or the associated support system (e.g., CEMS shelter, data acquisition and handling system or "DAHS"). Initial performance testing must be conducted to certify the CEMS and thereafter periodically to satisfy appendix F requirements. The CEMS (including its DAHS) must be maintained and quality assurance procedures undertaken utilizing either third party technicians, in-house technicians or a combination of both.

In contrast, the monitoring, recordkeeping, and reporting in the permit would not, in comparison, be a significant undertaking. The Permittee already operates ESP field-specific voltage and current monitoring and recordkeeping equipment. Complying with NESHAP DDDDD CPMS requirements (made applicable by Region 10 to voltage and current monitoring) is a minor and reasonable burden on the Permittee. NESHAP DDDDD requires the same of solid fuel boilers using a wet ESP to comply with PM emission limits. Operating a portable emissions analyzer capable of measuring CO and O2 on a dry basis once a month for at least 60 minutes is relatively inexpensive compared to installing, operating and maintaining a CO CEMS and associated support system in compliance with appendices B and F to 40 CFR part 60. Like EPA Reference Methods 3A (O2) and 10 (CO), the Permittee is required to measure O2 and CO simultaneously at one, three or twelve sampling points in the stack (depending on degree of stratification) in order to obtain a representative measurement result. However, only one 60-minute "test run" is required in contrast to the three 60-minute test runs required of a NESHAP DDDDD performance test. Unlike EPA Reference Methods 3A and 10 performed to satisfy NESHAP DDDDD testing requirements, monthly monitoring is not required to include a post-run system bias check, drift assessment, or adjustment to measurements for bias. Thus, in determining the appropriate supplemental monitoring, recordkeeping, and reporting, EPA has elected to impose the least burdensome requirements.

Over the course of this five-year title V permit and as discussed below, the Permittee will monitor, record and report information related to ESP field-specific daily average voltage and current excursions and monthly CO monitoring results. The reports are due semi-annually. The Permittee will also periodically (annually or every three years depending on boiler operating load, pollutant and proximity of emissions to emission limit) conduct performance testing and report the results within 60 days of the test. Region 10 will evaluate this information (and anything further that is relevant) to assess whether CO and PM CEMS should be required in the future.

<u>Permit Condition 5.16</u> requires the mill to install, operate, certify and maintain a COMS because the mill uses a dry ESP to reduce PM emissions and has elected to demonstrate compliance through performance testing. Condition 5.13 requires all opacity 6-minute averages be recorded in addition to 24-hour block averages. Because PotlatchDeltic is already required to use the COMS to record all 6-minute opacity averages, the same COMS will also be used to assure compliance with the FARR 6-minute 20% average visible emissions limit.

<u>Conditions 5.17 and 5.18</u> require the Permittee to install, operate and maintain an exhaust gas oxygen analyzer and steam generating rate monitoring system on each boiler. Each of these systems is a continuous parameter monitoring system as that term is defined in 40 CFR 63, Subpart A.

<u>Condition 5.19</u> are NESHAP DDDDD monitoring requirements for oxygen analyzer, steam generating rate monitoring system and the ESP secondary voltage and current. The requirements apply to ESP secondary voltage and current monitoring systems pursuant to 40 CFR 71.6(c)(1) in order to supplement NESHAP DDDDD PM monitoring as explained for Permit Conditions 5.14 and 5.15 above.

<u>Conditions 5.20 and 5.21</u> are NESHAP DDDDD monitoring requirements applicable to the COMS, oxygen analyzer, steam generating rate monitoring system and ESP secondary voltage and current monitoring systems. Note that the Permittee is required to develop and implement a site-specific monitoring plan for all systems. The requirements apply to ESP secondary voltage and current monitoring

systems pursuant to 40 CFR 71.6(c)(1) in order to supplement NESHAP DDDDD PM monitoring as explained for Permit Conditions 5.14 and 5.15 above.

Permit Condition 5.22 includes NESHAP Subpart DDDDD recordkeeping requirements. Also included in Conditions 5.22.3 and 5.22.4 is a recordkeeping requirement for ESP secondary voltage, current and power monitoring data. Condition 5.22.5 is a NESHAP Subpart DDDDD recordkeeping requirement related to tracking the amount and type of fuel combusted in boilers monthly. Conditions 5.22.8 and 5.22.9 reflect NESHAP DDDDD recordkeeping requirements related to malfunctions of the boiler, air pollution control equipment and monitoring equipment. Although NESHAP DDDDD does not require similar recordkeeping related to inspection, maintenance and repair of the ESP, Condition 5.22.10 requires such recordkeeping under authority of 40 CFR 71.6(c)(1). Such records provide information regarding whether the Permittee is complying with the Condition 5.8 requirement to operate and maintain air pollution control equipment consistent with good air pollution control practices for minimizing emissions. Permit Conditions 5.22.12 through 5.22.14 apply only to those startups for which PotlatchDeltic relies on the paragraph (2) of the definition of “startup” in 40 CFR 63.7575.

Permit Condition 5.23 requires the Permittee to report PB-1 and PB-2 monthly CO monitoring results and associated information to the EPA semi-annually. The requirement was added using Part 71 authority for the same reasons as the supplemental CO monitoring in Condition 5.14.8 discussed above.

Permit Conditions 5.24 through 5.31 are NESHAP Subpart DDDDD notification and reporting requirements. Prior to conducting a performance test, the Permittee must submit a site-specific test plan for EPA review and approval. The test plan must provide steam generating rate data pursuant to Permit Condition 5.25.2 to inform the Region’s decisionmaking as to the operating conditions under which testing must be performed. Each time the boiler is tested, boiler operating limits are either confirmed or re-established. Permit Condition 5.26.5 requires the Permittee to submit an administrative amendment request to keep the permit current. Elements of the requirements in Conditions 5.26.2 and 5.27 were added to satisfy the requirement in 40 CFR 71.6(c)(1) to include compliance certification, testing, monitoring, recordkeeping, and reporting sufficient to assure compliance with the applicable requirement.

Permit Condition 5.32 ensures PotlatchDeltic maintains the flexibility provided under NESHAP Subpart DDDDD to meet the requirements of the rule using different compliance options other than the option it is currently using. PotlatchDeltic is currently complying with NESHAP Subpart DDDDD HCl, Hg, CO and PM limits through performance testing and associated continuous monitoring. PM is a surrogate for TSM, and although there is no permit condition that limits TSM stack emissions, the NESHAP allows PotlatchDeltic to demonstrate compliance with the TSM limit rather than the PM limit. For certain pollutants, PotlatchDeltic has indicated that it may, in the future, choose to demonstrate compliance through fuel sampling and analysis. Although no permit amendment is necessary prior to switching compliance options, an amendment may be necessary afterward to extract requirements associated with obsolete compliance options and to create permit conditions reflecting new applicable requirements.

Permit Condition 5.33 incorporates NESHAP DDDDD requirements that apply generally by reference into the permit. See Appendix B to this statement of basis for details.

Permit Condition 5.34 requires the Permittee to comply with applicable NESHAP Subpart A general provisions referenced in Table 10 to NESHAP DDDDD. Specific requirements are included in Appendix to the permit and requirements that apply generally have been incorporated by reference. See Appendix B to this statement of basis for details.

Permit Section 6 – Unit-Specific Requirements for EU-2 – Veneer Dryers VD-1, VD-2, VD-3 and VD-4

Permit Condition 6.1 limits PM emissions from veneer dryer roof vents, cooling sections stacks, heating section bypass stacks and the RCO[34]. The permit condition also contains the method for determining compliance. The limit applies at all times. No unit-specific PM testing is required of the veneer dryer vents (from which emissions from leaks are released to atmosphere) and cooling section stacks given that the volume of gas handled by typical roof vents and cooling sections are not known to cause PM grain loading issues. No unit-specific testing of the RCO is required based upon previous unit-specific test results and source category testing that suggests no control of heating section exhaust is necessary to comply with the 0.1 gr/dscf limit. September 24, 2008, EPA RM5 emissions testing of the RCO stack (while the RCO was combusting supplementary propane fuel and oxidizing veneer dryer heated section exhaust) measured three-run average PM emissions of 0.0029 gr/dscf. This PM concentration represents 3 percent of the emission limit. Six one-hour test runs of uncontrolled heating section exhaust from another veneer dryer located in Indian country (three runs while processing white wood and three while processing red wood) measured a high one-hour average PM concentration of 0.0333 gr/dscf. This represents 33 percent of the FARR limit. Given that PotlatchDeltic only diverts veneer dryer heating section exhaust to the atmosphere on rare occasions (as evidenced by NESHAP Subpart DDDD compliance reports), and given that emissions are anticipated to be approximately one-third of the emission limit, no unit-specific testing of bypass stacks is being required. If visible emission monitoring identifies a visible emission compliance concern, testing may be necessary to assure compliance with the FARR grain loading limit for these emission units.

Permit Condition 6.2 limits the sulfur dioxide emissions from the RCO stack and describes the methods for determining compliance. The limit applies at all times. The veneer dryer heated zone exhaust is not expected to contribute any sulfur to RCO stack emissions. Because the oxidizer only uses propane as fuel, SO_2 emissions are expected to be well below the emission limit of 500 ppmdv at 7% O_2. For an example, see the calculation below.

SO_2 concentration = (sulfur content$_{\text{commerical propane}}$ by mass) X (density$_{\text{propane}}$) X (1/heating value$_{\text{propane}}$) X ($CF_{Btu \rightarrow MMBtu}$) X (Mass Ratio SO_2 Out/S In) X (1/F_d factor$_{\text{propane}}$) X ($CF_{lb/ft3 \rightarrow ppmv@20°C}$)

= (185 lb S/1x10^6 lb fuel) X (4.24 lb fuel/gal fuel) X (gal fuel/90,500 Btu) X (1x10^6 Btu/MMBtu) X (2 lb SO_2/lb S) X (MMBtu/8710 dscf) X (385.6x10^6 dscf·ppmdv SO_2/32 lb SO_2)

= 23.9 ppmdv at 0% O_2

Where: Sulfur content$_{\text{commercial propane)}}$ by mass = 123 ppm. See GPA Liquefied Petroleum Gas Specifications Standard 2140-97.

F_d factor = 8710 dscf/MMBtu. See 40 CFR 60, Appendix A, RM19, Table 19-2.

[34] The RCO is not subject to the “corrected to 7% O2” combustion source stack grain loading standard in 40 CFR 49.125(d)(1). It is appropriate to “correct” the exhaust concentration of a combustion source stack to a standard %O2 (to account for unwarranted introduction of air into the exhaust) when the subject pollutant is primarily the by-product of combustion. But in this case, the PM in the RCO exhaust is primarily from the veneer dryer heating section exhaust and not the byproduct of combusting propane to raise the temperature in the RCO to promote oxidation of organics across the catalyst. In addition, the 2008 test report shows that the O2 concentration in the heating section exhaust is relatively high at 21% while a relatively small amount of combustion air (O2) is introduced at the RCO to assist in the combustion of propane. The relatively small amount of PM generated from the combustion of PM will be counted when determining compliance with the process unit grain loading standard.

$CF_{lb/ft3 \rightarrow ppmv@20°C} = 385.6x10^6$ dscf·ppmdv SO_2/32 lb SO_2. See Conversion Factors for Common Air Pollution Measurements – Atmospheric Gases presented on page A-27 of Appendix A to AP-42.

The recordkeeping (fuel vendor records showing sulfur content of the propane or the type of LPG received) required in Permit Condition 4.7 will serve as the monitoring to assure compliance for the RCO.

Permit Condition 6.3 requires the Permittee to conduct EPA RM9 visible emissions observations of veneer dryer heating section bypass stacks in the event heating section emissions are diverted away from the catalytic oxidizer. The FARR 20% visible emissions limit applies at all times. The requirement was added to satisfy the requirement in 40 CFR 71.6(c)(1) to include monitoring, recordkeeping, and reporting sufficient to assure compliance with the applicable requirement.

Permit Conditions 6.4 through 6.27 are NESHAP Subpart DDDD requirements applicable to the four veneer dryers and the two-can propane-fueled regenerative catalytic oxidizer that reduces veneer dryer heated zone HAP emissions routed to it. Use of the two alternating catalyst beds helps reduce the temperature needed in the combustion chamber to achieve the 90 percent control requirement. During September 24, 2008 emissions testing that demonstrated a 94% control efficiency, a combustion chamber temperature of 707°F (a thermocouple on each end of the chamber) was observed. During August 3-4, 2023 emissions testing that PotlatchDeltic asserts demonstrated a 93% control efficiency, a combustion chamber temperature of 840°F was observed. See Appendix H to this statement of basis for a derivation of the two temperature values. The 707°F and 840°F values reflect the average of the three minimum 15-minute temperatures monitored during the respective three test runs pursuant to 40 CFR 63.2262(l). Region 10 is evaluating the November 3, 2023 revised source test report for testing conducted August 2023. The Permittee is required to maintain a 3-hour block average combustion chamber temperature above the 707°F threshold value at all times. Except for the year in which performance testing is conducted, the mill is required to annually check the catalyst material to determine whether it needs to be replaced. Because the mill is satisfying the add-on control system compliance option during all drying operations (including drying veneer that has previously been dried, but not to the desired moisture content), the NESHAP does not require the Permittee to comply with the redry work practice requirements. Before introducing veneer to the dryers, both the dryers and the RCO are brought up to temperature such that no veneer dryer heating section exhaust is diverted to the bypass stacks. Similarly, the oxidation catalyst continues to operate as the last piece of veneer exits the dryer. In this way, no excess emissions are generated during startup and shutdown.

The requirements for the RCO to achieve 90% control of veneer dryer heating zone exhaust and for the RCO temperature to remain above 707°F apply at all times except during safety-related shutdowns, when Condition 6.5.1 applies. The NESHAP provides for PotlatchDeltic to apply to Region 10 for approval of a routine control device maintenance exemption. If approved, the requirements in question would not apply during periods of routine control device maintenance. PotlatchDeltic has not submitted such a request to Region 10 for approval.

Pursuant to Permit Condition 6.5.1, PotlatchDeltic is required to follow documented site-specific procedures to reduce emissions during safety-related shutdown. PotlatchDeltic is required to follow a plan for minimizing fugitive emissions from the veneer dryers pursuant to Permit Condition 6.6.1.

Although the Permittee is required to conduct performance testing every 60 months pursuant to Condition 6.11, the minimum catalytic oxidizer temperature limit in Condition 6.8 is not automatically updated to reflect the temperature observed during the most recent test. Pursuant to Condition 6.8.2, the Permittee may choose to establish a different minimum catalytic oxidizer combustion chamber temperature from the one established in September 2008 by submitting notification pursuant to Condition 6.22.2.

Condition 6.21.4 is the requirement in 40 CFR 63.2280(d)(1) to submit NOCS related to the facility following safety-related shutdown procedures. See row 6 of Table 6 to NESHAP Subpart DDDD for initial compliance demonstration. The Permittee was required to have conducted an initial compliance demonstration by September 12, 2021 given the August 13, 2021 compliance date pursuant to 40 CFR 63.2261(b). The NOCS was required to have been submitted to Region 10 within 30 days of completing the initial compliance demonstration.

Permit Condition 6.27 incorporates by reference into the permit the NESHAP DDDD requirements that apply generally to the Permittee. See Appendix B to this statement of basis for details.

Permit Condition 6.28 requires the Permittee to comply with applicable NESHAP Subpart A general provisions referenced in Table 10 to PCWP MACT. Specific requirements are included in Appendix to the permit and requirements that apply generally have been incorporated by reference. See Appendix B to this statement of basis for details.

Permit Section 7 – Unit-Specific Requirements for EU-3 – Oil and Edge Seal Line (ES), Wood Putty Patching (WP) and Surface Coating Logos (SCL)

Permit Conditions 7.1 through 7.5 are NESHAP DDDD requirements applicable to ES, WP and SCL. Each activity is a Group 1 miscellaneous coating operation. Compliance with Condition 7.3.1 is documented by securing and maintaining for each coating (a) Material Safety Data Sheet and (b) statement from the manufacturer certifying that its coating is a “non-HAP coating” as that term is defined by NESHAP DDDD. Region 10 has determined that the NESHAP DDDD monitoring required at Row 5 to Table 8 of the subpart is sufficient to assure compliance with the NESHAP DDDD emission limitation at Row 3 to Table 3 of the subpart. EPA Region 10 has determined that no additional monitoring is necessary to assure compliance with the underlying emission limitation.

Permit Condition 7.5 incorporates by reference into the permit the NESHAP DDDD requirements that apply generally to the Permittee. See Appendix B to this statement of basis for details.

Permit Condition 7.6 requires the Permittee to comply with applicable NESHAP Subpart A general provisions referenced in Table 10 to NESHAP DDDD. Specific requirements are included in Appendix to the permit and requirements that apply generally have been incorporated by reference. See Appendix B to this statement of basis for details.

Permit Section 8 - Unit-Specific Requirements for EU-4 – Compression Ignition Internal Combustion Engines IC-1 and IC-2

Permit Condition 8.1 limits PM emissions from this emission unit and describes the method for determining compliance. The limit applies at all times. No unit-specific RM5 PM testing is required given that PotlatchDeltic only intends to operate the engines in an emergency and as needed for maintenance checks and readiness testing. If the unit-specific visible emission monitoring required in Permit Condition 8.10 identifies a visible emission compliance concern, additional monitoring or testing may be necessary to assure compliance with the FARR grain loading limit for these emission units.

Permit Condition 8.2 limits the SO_2 emissions and describes the methods for determining compliance. The limit applies at all times. Because the engines use only Grade 1 or 2 ULSD fuel, SO_2 emissions are expected to be well below the emission limit of 500 ppmdv at 7% O_2. For an example, see the calculation below.

$$SO_2 \text{ concentration} = (\text{sulfur content}_{ULSD} \text{ by mass}) \times (\text{density}_{diesel}) \times (1/\text{heating value}_{diesel}) \times (CF_{Btu \rightarrow MMBtu}) \times (\text{Mass Ratio } SO_2 \text{ Out/S In}) \times (1/F_d \text{ factor}_{diesel}) \times (CF_{lb/ft3 \rightarrow ppmv@20°C})$$

= (15 lb S/1x10^6 lb fuel) X (7.05 lb fuel/gal fuel) X (gal fuel/140,000 Btu) X (1x10^6 Btu/MMBtu) X (2 lb SO_2/lb S) X (MMBtu/9190 dscf) X (385.6x10^6 dscf·ppmdv SO_2/32 lb SO_2)

= 2.0 ppmdv at 0% O_2

Where: Sulfur content$_{ULSD}$ by mass = 15 ppm. From application.

F_d factor = 9190 dscf/MMBtu. See 40 CFR 60, Appendix A, RM19, Table 19-2.

$CF_{lb/ft3 \rightarrow ppmv@20°C}$ = 385.6x10^6 dscf·ppmdv SO_2/32 lb SO_2. See Conversion Factors for Common Air Pollution Measurements – Atmospheric Gases presented on page A-27 of Appendix A to AP-42.

The recordkeeping (fuel vendor records showing sulfur content of the Grade 1 or 2 diesel or ULSD receipts) required in Permit Conditions 4.6 assures compliance with the FARR exhaust gas SO_2 limit for these emission units. No unit-specific testing is required.

Permit Conditions 8.3 through 8.6 and 8.8 and 8.10 are NSPS IIII requirements applicable to CI engines that are only operated in emergencies and on a limited basis for maintenance checks, readiness testing and other non-emergency situations. Because PotlatchDeltic is prohibited from operating either engine for more than 100 hours per year (except for emergencies), the engines are not subject to emission and operating limitations that may require post-combustion controls be installed. PotlatchDeltic is required to minimize emissions by maintaining the engines according to a written plan authored by the manufacturer or PotlatchDeltic. The certified emissions life (as defined in 40 CFR 60.4219) is the first ten years or first 8,000 operating hours, whichever comes first, pursuant to 40 CFR 1039.101(g)(1)(v). Regardless of whether an engine's certified emission life has been exhausted, the Permittee is still required to operate and maintain the engine. PotlatchDeltic is required to maintain records of engine operation and maintenance performed. Because the engines are considered emergency fire pump engines, NSPS IIII requires that they be certified by the manufacturer to comply with emission standards in NSPS IIII, Table 4. If the engines were not considered emergency fire pump engines, they would be subject to more stringent emission standards in 40 CFR 1039 pursuant to 40 CFR 60.4201(a). Thus, it is critical for the Permittee to track their operating hours to maintain their classification as emergency engines.

Permit Condition 8.8 includes a requirement to install a non-resettable hour meter if one does not already exist with a requirement to keep a record of hours of operation using the hour meter and the corresponding reason for use. This condition assures compliance with Permit Condition 8.5 limiting hours of operation. Condition 8.9 has been included using Part 71 authority to assure compliance with Conditions 8.4.1 and 8.4.3.

Permit Condition 8.7 requires monitoring to assure compliance with the FARR visible emissions limit in Permit Condition 3.9. The requirement was added using Part 71 authority. Each engine only operates during emergencies, and during maintenance checks and readiness testing not to exceed 100 hours per year (non-emergency operation limit). Region 10 is requiring the Permittee to conduct visible emissions observations (and if detected, RM9 opacity determinations) of each engine's exhaust while operating at least once per year. Fugitive and visible emission monitoring required in Permit Conditions 4.8 through 4.13 does not apply because the engines will likely not be operating during a monthly or quarterly walk-through of the facility.

Permit Condition 8.11 incorporates by reference into the permit the NSPS IIII requirements that apply generally to the Permittee. See Appendix B to this statement of basis for details.

Permit Condition 8.12 requires the Permittee to comply with applicable NSPS Subpart A general provisions referenced in Table 8 to NSPS IIII. Requirements that apply generally have been incorporated by reference. See Appendix B to this statement of basis for details.

Permit Section 9 – Unit-Specific Requirements for EU-5 – Spark Ignition Internal Combustion Engines IC-3, IC-4, IC-5, IC-6, IC-7, IC-8, IC-9, IC-10 and IC-11

Permit Condition 9.1 limits the PM emissions and describes the method for determining compliance. The limit applies at all times. No unit-specific RM5 PM testing is required given that PotlatchDeltic only intends to operate the engines in an emergency and as needed for maintenance checks and readiness testing. If the unit-specific visible emission monitoring required in Permit Conditions 4.8 through 4.12 identifies a visible emission compliance concern, additional monitoring or testing may be necessary to assure compliance with the FARR grain loading limit for these emission units.

Permit Condition 9.2 limits the SO_2 emissions and describes the methods for determining compliance. The limit applies at all times. Because the engines use only propane as fuel, SO_2 emissions are expected to be well below the emission limit of 500 ppmdv at 7% O_2. For an example, see the calculation below.

SO_2 concentration = (sulfur content$_{\text{commercial propane}}$ by mass) X (density$_{\text{propane}}$) X (1/heating value$_{\text{propane}}$) X ($CF_{Btu \rightarrow MMBtu}$) X (Mass Ratio SO_2 Out/S In) X (1/F_d factor$_{\text{propane}}$) X ($CF_{lb/ft3 \rightarrow ppmv@20°C}$)

= (185 lb S/1x10^6 lb fuel) X (4.24 lb fuel/gal fuel) X (gal fuel/90,500 Btu) X (1x10^6 Btu/MMBtu) X (2 lb SO_2/lb S) X (MMBtu/8710 dscf) X (385.6x10^6 dscf·ppmdv SO_2/32 lb SO_2)

= 23.9 ppmdv at 0% O_2

Where: Sulfur content$_{\text{commercial propane)}}$ by mass = 185 ppm. See GPA Liquefied Petroleum Gas Specifications Standard 2140-97.

F_d factor = 8710 dscf/MMBtu. See 40 CFR 60, Appendix A, RM19, Table 19-2.

$CF_{lb/ft3 \rightarrow ppmv@20°C}$ = 385.6x10^6 dscf·ppmdv SO_2/32 lb SO_2. See Conversion Factors for Common Air Pollution Measurements – Atmospheric Gases presented on page A-27 of Appendix A to AP-42.

The recordkeeping (fuel vendor records showing sulfur content of the propane or the type of LPG received) required in Permit Condition 4.7 will serve as the monitoring to assure compliance with the FARR exhaust gas SO_2 limit for these emission units. No unit-specific testing is required.

Permit Conditions 9.3 through 9.5 and 9.7 and 9.8 are NSPS JJJJ requirements applicable to SI engines that are only operated in emergencies and on a limited basis for maintenance checks, readiness testing and other non-emergency situations. PotlatchDeltic is required to minimize emissions by maintaining such engines according to a written plan authored by the manufacturer or PotlatchDeltic. For IC-3, IC-7, IC-8, IC-10 and IC-11, the certified emissions life (as defined in 40 CFR 60.4248) is the first five years or first 1,000 operating hours, whichever comes first pursuant to 40 CFR 1054.107(a)(1). For IC-4, IC-5, IC-6 and IC-9, their certified emissions life pursuant to 40 CFR 60.4248 is no shorter than any of the following: (a) 1,000 hours of operation, (b) the manufacturer's recommended overhaul interval, or (c) the manufacturer's mechanical warranty for the engine. Regardless of whether an engine's certified emission life has been exhausted, the Permittee is still required to operate and maintain the engine. PotlatchDeltic is required to maintain records of engine operation and maintenance performed. Because IC-4 and IC-5 are considered emergency engines, NSPS JJJJ requires that they be certified by the manufacturer to comply with emission standards for emergency engines in Table 1 to 40 CFR 60, Subpart JJJJ. If the engines were not considered emergency engines, they would be subject to more stringent emission standards in 40 CFR 1048 pursuant to 40 CFR 60.4233(d). Because IC-6 and IC-9 are considered emergency engines, NSPS JJJJ requires that they be certified by the manufacturer to comply with EPA Phase I class II nonroad engine emission standards for propane fuel in 40 CFR 1054, Subpart I. If the engines were not considered emergency engines, they would be subject to more stringent emission standards in 40 CFR 1048 pursuant to 40 CFR 60.4231(c). Thus, it is critical for the Permittee to track IC-4, IC-5, IC-6 and IC-9 operating hours to maintain their classification as emergency engines. Because SI engines IC-3, IC-7, IC-8, IC-10 and IC-11 are certified by the manufacturer to comply with EPA Phase 3, Class II emission standards for propane-fired nonhandheld engines in 40 CFR 1054, the hour restriction for emergency engines does not change the NSPS requirements and there is no reason to require an hour meter using Title V authority. There is no less stringent emission standards for emergency engines for this category of engines.

Permit Condition 9.7 for IC-4, IC-5, IC-6 and IC-9 includes the requirement to install a non-resettable hour meter if one does not already exist with a requirement to keep a record of hours of operation using the hour meter and the corresponding reason for use. This condition assures compliance with Permit Condition 9.5 limiting hours of operation and is only necessary for engines less than 130 horsepower manufactured on or after July 1, 2008, that do not meet the standards applicable to non-emergency engines. Permit Condition 9.8 is applicable to all engines and includes a requirement to keep records of the maintenance conducted on the engine.

Certain emergency demand response provisions of NSPS JJJJ vacated by the DC Circuit Court of Appeals (May 4, 2016 mandate) no longer apply, and thus are not included in the permit. An engine may not operate in circumstances described in the vacated provisions unless it is in compliance with the emission standards and other applicable requirements for a non-emergency engine.

Permit Condition 9.6 requires monitoring to assure compliance with the FARR visible emissions limit in Permit Condition 3.9. The requirement was added using Part 71 authority. Each engine only operates in an emergency and during maintenance checks and readiness testing not to exceed 100 hours per year (non-emergency operation limit). Region 10 is requiring the Permittee to conduct visible emissions observations (and if detected, RM9 opacity determinations) of each engine's exhaust while operating at least once per year. Fugitive and visible emission monitoring required in Permit Conditions 4.8 through 4.13 does not apply because the engines will likely not be operating during a monthly or quarterly walk-through of the facility.

Permit Conditions 9.9 incorporates by reference into the permit the NSPS Subpart JJJJ requirements that apply generally to the Permittee. See Appendix B to this statement of basis for details.

Permit Condition 9.10 requires the Permittee to comply with applicable NSPS Subpart A general provisions referenced in Table 3 to NSPS JJJJ. Those requirements have been incorporated by reference into the permit. See Appendix B to this statement of basis for details.

Permit Section 10 – Unit-Specific Requirements for EU-6 – Lumber Drying Kiln LK-5

Permit Condition 10.1 limits PM emissions and describes the method for determining compliance. The limit applies at all times. No unit-specific testing or monitoring is required. If the visible and fugitive emission monitoring required in Permit Conditions 4.8 through 4.13 identify a compliance concern, additional monitoring or testing may be necessary to assure compliance with the FARR grain loading limit for these emission units.

Permit Condition 10.2 restricts the species of wood that may be dried in LK-6 consistent with the demonstration in PotlatchDeltic's application in support of PSD and minor NSR permits issued in June 2019.

Permit Condition 10.3 assures compliance with the PSD BACT and minor NSR control technology review determination for construction of kiln LK-6 in Condition 10.4.1. The requirement was established in the third revision to the PSD permit and second revision to the minor NSR permit. See the support documents for those permit actions for details.

Permit Conditions 10.4 reflects the PSD BACT and minor NSR control technology review determination for construction of kiln LK-6. Conditions 10.4.1 and 10.4.2 were issued and became effective in the third revision to the PSD permit and second revision to the minor NSR permit. Conditions 10.4.3 through 10.4.5 were established in the original June 2019 PSD and minor NSR permits. See the support documents for those permit actions for details.

Permit Condition 10.5 reflects the minor NSR control technology review determination for construction of kiln LK-6. The requirement was established in the original June 2019 minor NSR permit and reflects FARR visible emissions limit in 40 CFR 49.124(d). See the permit analysis for that permit action for details.

Permit Conditions 10.6 and 10.7 establish allowable daily and annual emission limits that reflect the emission rates modeled to protect the PM2.5 NAAQS in support of minor NSR permit authorizing construction of LK-6. These permit conditions specify the emission factors (lb PM2.5/mbf lumber) and daily and annual operational rates (mbf/day, mbf/year from Conditions 10.10.5 and 10.10.2, respectively) to use in calculating daily and annual PM2.5 emissions for determining compliance. See the permit analysis for that permit action for details.

Permit Condition 10.8 is the LK-6 annual allowable emission limit for PM10. Pursuant to 40 CFR 49.155(a)(2), the minor NSR permit must include an annual allowable emissions limit for each affected emissions unit and for each regulated NSR pollutant emitted by the emission unit if the unit is issued an enforceable emission limitation lower than the potential to emit of that unit. Because PM10 is assumed equal to PM2.5, the PM10 limit and emission factor reflects the PM2.5 limit and emission factor in Condition 10.7.

Permit Condition 10.9 restricts VOC emissions from LK-6 to 50 tpy to reflect PotlatchDeltic's upper bound estimate of VOC emissions expected from the project to construct the kiln considering the species of wood that will be dried. Region 10 considered this restriction on emissions in finalizing the AQIA evaluation and BACT analysis for the PSD permit. The limit is an annual limit, consistent with the annual emissions used in the ambient air quality and BACT analyses, rather than a rolling 12-month limit used for limiting "potential" emissions. See the fact sheet for Permit No. R10PSD00100 for details.

Permit Condition 10.10 reflects LK-6 monitoring requirements in Permit No.'s R10PSD00103 and R10TNSR01803. The monitoring is necessary to assure compliance with PSD BACT and minor NSR control technology review requirements. The monitoring is also necessary to provide operating data necessary to calculate PM2.5, PM10 and VOC emissions to demonstrate compliance with emission limits. See support documents for original permits issued in June 2019 for details.

Permit Conditions 10.11 through 10.14 are from Permit No. R10TNSR01803 and R10PSD00103.

Permit Condition 10.11 requires that the LK-6 temperature and moisture monitoring systems/equipment be maintained and accurate.

Permit Condition 10.12 requires LK-6 PM10 and VOC emissions be calculated annually. The requirement to calculate PM2.5 emissions is in Condition 4.21.

Permit Condition 10.13 is deviation reporting in the semiannual title V monitoring report specific to kiln LK-6. Although the reporting frequency in the underlying NSR permits is annually, title V requires semiannual deviation reporting.

Permit Condition 10.14 requires the kiln LK-6 O&M manual be kept up to date.

Permit Section 11 - Unit-Specific Requirements for EU-7 – Pneumatic Conveyance and Dust Capture Systems

Permit Condition 11.1 limits PM emissions and describes the method for determining compliance. No unit-specific testing or monitoring is required. If the visible and fugitive emission monitoring required in Permit Conditions 4.8 through 4.13 identify a compliance concern, additional monitoring or testing may be necessary to assure compliance with the FARR 0.1 gr/dscf grain loading limit for these emission units.

On page 2 of EPA's document entitled, Fabric Filter Bag Leak Detection Guidance, EPA-454/R-98-015, September 1997 at https://www3.epa.gov/ttnemc01/cem/tribo.pdf, EPA states, "Fabric filters are capable of extremely high control efficiencies of both coarse and fine particles; outlet concentrations as low as 20 mg/dscm (0.01 gr/dscf) can be achieved with most fabric filter systems. During May 1996 testing of newly installed BH-2 (Planer Shavings Baghouse) and BH-3 (Trimmer/Chipper Baghouse), PM emissions of 0.0059 and 0.0069 gr/dscf, respectively, were measured. Both measurements are less than 10% of the FARR PM limit. Three 60-minute PM2.5 runs of each baghouse in 2020 all resulted in reporting emissions less than the method detection limit. Region 10 is not aware of PotlatchDeltic having tested any other baghouses (some older than others) at the mill. Only three cyclones, CY-2, CY-5 and CY-9 emit directly to atmosphere. CY-2 and CY-5 receive only green (wet) wood residue. Pneumatic conveyance of green wood residue (heavier and more likely to be captured by cyclone) is less likely to generate PM emissions as compared dry wood residue (lighter and less likely to be captured by cyclone). CY-9 receives metal filings. Although the application does not include information regarding actual emissions from these three cyclones, Region 10 does not anticipate emissions to be in excess of the FARR 0.1 gr/dscf limit. If process equipment (generating dust and pneumatically conveying wood residue) other than CY-2, CY-5 and CY-9 operates with associated baghouses off-line, PM emissions may exceed the FARR visible emissions and grain loading limits.

Permit Conditions 11.2 and 11.3 establish allowable daily and annual emission limits that reflect the emission rates modeled to protect the PM2.5 NAAQS in support of Permit No. R10TNSR01803. These permit conditions specify the emission factors and daily and annual operational rates to use in calculating daily and annual PM2.5 emissions for determining compliance.

Permit Conditions 11.4 and 11.5 are necessary for the protection of the NAAQS. The requirements were required to have been satisfied upon initial startup of LK-6 in October 2019 pursuant to Condition 2.18 of Permit No. R10TNSR01800.

Permit Conditions 11.6 and 11.7 are additional monitoring, recordkeeping and reporting measures. The requirement were added using Part 71 authority. PotlatchDeltic is being required to record and report each instance that EU-7 process equipment operated without the associated control equipment also online. The Permittee is required to use baghouses BH-2, 3, 4, 5, 10 and 11 pursuant to Condition 4.18 based upon underlying requirement in Permit No. R10TNSR01803. That requirement does not apply to baghouses BH-1, 6, 7, 8, 9 and 12.

Permit Section 12 – Unit-Specific Requirements for EU-8 – Plywood Presses PV-1 and PV-2

Permit Condition 12.1 limits PM emissions and describes the method for determining compliance. The limit applies at all times. Emissions testing of a similar source recorded PM emissions of 0.002 gr/dscf. A total temporary enclosure was erected to capture and sample the exhaust from two softwood plywood presses at a panelboard facility in Oregon. The measured PM emissions represent 2% of the FARR 0.1 gr/dscf emission limit.

No unit-specific testing or monitoring is required for EU-8 given demonstrated low emissions from a similar source. If the visible and fugitive emission monitoring required in Permit Conditions 4.8 through

4.13 identify a compliance concern, additional monitoring or testing may be necessary to assure compliance with the FARR grain loading limit for these emission units.

Permit Section 13 – Unit-Specific Requirements for EU-9 – Plant Traffic (PT)

Permit Conditions 13.1 and 13.2 establish allowable daily and annual emission limits that reflect the emission rates modeled to protect the PM2.5 NAAQS in support of Permit No. R10TNSR01803. These permit conditions specify the emission factors and daily and annual operational rates to use in calculating daily and annual PM2.5 emissions for determining compliance.

Permit Condition 13.3 requires the Permittee to track activities related to lumber manufacturing that influence PM2.5 emissions generated by plant traffic on paved and unpaved areas. Condition 13.1 of the permit limits these emissions to 19.39 lb/day. The emission factor the Permittee is required to use to calculate daily emissions assumes a certain degree of emission reduction as the result of restricting traffic speed to 15 miles-per-hour on unpaved areas, watering paved and unpaved areas, and sweeping paved areas. Monitoring and recording details of these work practices is important to assure the representativeness of the emission factor, and moreover to assure that actual emissions are not greater than reported.

Permit Appendix – NESHAP Subpart A Requirements Applicable to EU-1, EU-2 and EU-3

Specific NESHAP subpart A requirements applicable to EU-1, EU-2 and EU-3 are included in Appendix to the permit. Conversely, NESHAP subpart A requirements that apply generally to EU-1, EU-2 and EU-3 have been incorporated by reference. See Appendix B to this statement of basis for the requirements that have been incorporated by reference.

6. Public Participation

6.1 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 public comment period of at least 30 days for actions pertaining to a draft Title V permit. For this permit action, the requirements of 40 CFR 71.11(a)(5) and 71.8 will be satisfied as follows:

1. Posting the public notice, draft permit, statement of basis and the draft administrative record (which includes the application and relevant supporting materials) on Region 10's website for the duration of the public comment period. Notice is also being provided in one edition of the weekly St. Maries Gazette Record.

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 and local air pollution control agencies that have jurisdiction over the area where the source is located, Tribal, city and county executives where the source is located, 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 the EPA's mailing list for Title V permitting actions. In this case, the affected states (as that term is defined in 40 CFR 71.2) are Idaho and Washington (contiguous to the Coeur d'Alene Reservation). Title V permit authorities Idaho Department of Environmental Quality and the Department of Ecology act on behalf of their governors in receiving notice of title V permit actions outside their jurisdiction. Because the

jurisdiction of title V permit authority Spokane Regional Clean Air Agency is located within 50 miles of the permitted source, notice is being provided to them as a courtesy.

6.2 Response to Public Comments and Permit Issuance

As required in 40 CFR 71.11(e), the EPA will consider all timely comments received when making a final decision. The EPA's response to any comments received during the public comment period or public hearing held for this permit will be addressed in this section of the final statement of basis. As required in 40 CFR 71.11(i), the EPA will notify the applicant and each person who submits written comments or requested notice of the final permit decision.