Attachment 1

Region 9’s Excerpts of Record

BEFORE THE ENVIRONMENTAL APPEALS BOARD
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C.

In re: Sierra Pacific Industries, Anderson PSD Permit No. Sac 12-01	Appeal Nos. PSD 13-01, PSD 13-02, PSD 13-03, and PSD 13-04

EPA REGION 9'S EXCERPTS OF RECORD
IN SUPPORT OF
EPA REGION 9'S RESPONSE TO PETITIONS FOR REVIEW

EPA Region 9 submits the attached Excerpts of Record in support of EPA Region's Response to Petitions for Review in the above-referenced case.

Date: April 23, 2013

Respectfully Submitted,

/S/ Kara Christenson

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EPA REGION 9'S EXCERPTS OF RECORD
for Sierra Pacific Industries, Anderson, PSD Permit No. Sac 12-01
With Citations to Certified Index to the Administrative Record ("AR")

1. SPI Anderson Final PSD Permit SAC-01, dated February 19, 2013 ("Final Permit"), AR VI.02.

2. SPI Anderson Ambient Air Quality Impact Report, dated September 12, 2012 ("AAQIR"), AR III.02

3. SPI Anderson Final Response to Comments, dated February 19, 2013 ("RTC"), AR VI.03

4. SPI Anderson PSD Permit Modification Application, dated March 25, 2010 ("March 2010 Application"), AR I.01 (pages 1-39 only)

5. SPI Anderson Updated Modeling and SUSD Analysis, dated May 30, 2012 ("May 2012 Modeling Submittal"), AR I.11

6. USEPA Comments SPI Anderson Completeness Letter, dated October 4, 2010, AR I.06

7. SPI Anderson Proposed PSD Permit Modification, dated September 12, 2012 ("Proposed Permit"), AR III.01

8. Public Notice for Proposed Permit, dated September 12, 2012, AR III.03; Public Notice for Final Permit, dated February 21, 2013, AR VI.05

9. Public Comments (Lawrence and Petitioners Coleman, Simpson, Strand only), AR IV.12, IV.05, IV.09, IV.10

10. Certified Index to the Administrative Record

11. SPI Anderson response to EPA incomplete letter, dated July 1, 2010, AR I.03 (partial -- maps only)

12. Report to Shasta County Planning Commission, dated June 14, 2012 AR V.04 (pages 1-7 only)

Excerpt 1

SPI Anderson Final PSD Permit SAC-01, dated February 19, 2013 (“Final Permit”), AR VI.02.

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PROPOSED PURSUANT TO THE REQUIREMENTS AT 40 CFR § 52.21

U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION IX

PSD PERMIT NUMBER: SAC 12-01

PERMITTEE: Sierra Pacific Industries
P.O. Box 496028
Redding, CA 96049-6028

FACILITY NAME: Sierra Pacific Industries- Anderson

FACILITY LOCATION: 19758 Riverside Avenue
Anderson, California 96007

Pursuant to the provisions of the Clean Air Act (CAA), Subchapter I, Part C (42 U.S.C. Section 7470, *et. seq.*), and the Code of Federal Regulations (CFR) Title 40, Section 52.21, the United States Environmental Protection Agency Region 9 (EPA) is issuing a *Prevention of Significant Deterioration* (PSD) air quality permit to Sierra Pacific Industries (SPI). This Permit applies to the approval to construct and operate a new stoker boiler capable of generating 31 MW of gross electrical output from the combustion of clean cellulosic biomass, and related auxiliary equipment.

SPI is authorized to construct and operate the 31 MW cogeneration unit at SPI-Anderson as described herein, in accordance with the permit application (and plans submitted with the permit application), the federal PSD regulations at 40 CFR § 52.21, and other terms and conditions set forth in this PSD Permit. Failure to comply with any condition or term set forth in this PSD Permit may be subject to enforcement action pursuant to Section 113 of the Clean Air Act. This PSD Permit does not relieve SPI from the obligation to comply with applicable federal, state, and Shasta County Air Quality Management District (District) air pollution control rules and regulations.

Per 40 CFR § 124.15(b), this PSD Permit becomes effective 30 days after the service of notice of this final permit decision unless review is requested on the permit pursuant to 40 CFR § 124.19.

Deborah Jordan
Director, Air Division

2-19-2013
Date

SIERRA PACIFIC INDUSTRIES - ANDERSON (SAC 12-01)
PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
PERMIT CONDITIONS

PROJECT DESCRIPTION

Sierra Pacific Industries, Inc. (SPI) applied for the approval to construct and operate a new stoker boiler capable of generating 31 MW of gross electrical output from the combustion of biomass and natural gas, and related auxiliary equipment. The original Prevention of Significant Deterioration (PSD) permit for this lumber manufacturing facility was issued in 1994 by the Shasta County Air Quality Management District (District). The site currently contains a wood-fired boiler cogeneration unit with associated air pollution control equipment and conveyance systems that produce steam to dry lumber in existing kilns. On March 3, 2003, USEPA revoked and rescinded the District's authority to issue and modify federal PSD permits for new and modified major sources of attainment pollutants in Shasta County. Therefore, EPA is issuing this PSD permit to authorize SPI to construct and operate the additional boiler and related auxiliary equipment described in this permit at the SPI-Anderson facility. The PSD permit previously issued by the District to SPI is still in effect and applies to existing equipment at the SPI-Anderson site.

Fuel for the new stoker boiler will be generated on site and received from other fuel sources, mainly other SPI facilities, to produce roughly 250,000 pounds per hour of steam. This steam will be used to dry lumber in existing kilns for the lumber operation, as well as feed a turbine that will drive a generator to produce electricity for use on site or for sale to the grid. A closed-loop three-cell cooling tower will be used to dispose of waste heat from the steam turbine.

This PSD permit for the modification requires the use of Best Available Control Technology (BACT) to limit emissions of nitrogen oxides (NO_x), carbon monoxide (CO), total particulate matter (PM), PM under 10 micrometers (μm) in diameter (PM_{10}) and PM under 2.5μm in diameter ($PM_{2.5}$) to the greatest extent feasible. Air pollution emissions from the modification will not cause or contribute to violations of any National Ambient Air Quality Standards (NAAQS) or any applicable PSD increments for the pollutants regulated under the permit.

Additional equipment includes the construction of an additional cooling tower and an emergency natural gas engine to power the emergency boiler recirculation pump.

EQUIPMENT LIST

Table 1 lists the new equipment that will be regulated by the proposed PSD permit:

Table 1: New Equipment List Regulated by the PSD Permit

ID	Unit	Description
U1	One Stoker Boiler with Grate	• Biomass-fired with natural gas burners for start-up • Maximum annual average heat input of approximately 468 MMBtu/hr and steam generation rate of 250,000 lbs/hr • Equipped with two natural gas burners, each with a maximum rated heat input of 62.5 MMBtu/hr • Equipped with selective non-catalytic reduction (SNCR) system to reduce NO_x, and multiclone with an electrostatic precipitator (ESP) to control PM emissions
U2	Cooling Tower	• Composed of three cells with an expected water load of 4.24 gallons per minute per square foot
U3	Emergency Engine	• 256hp at 1,800 rpm • Spark-ignition internal combustion, natural gas-fired • Powers emergency boiler recirculation pump • 40 CFR Part 60- Subpart JJJJ Compliant

Table 2 lists the existing equipment that is not included in this PSD permit. The equipment listed below is permitted by the District and the Permittee must comply with all applicable requirements. *Table 2* is provided for reference purposes only:

Table 2: Existing Equipment List

ID	Unit	Description
U4	One Wellons Stoker Boiler	• Biomass-fired with natural gas burners for start-up • Maximum annual average heat input of approximately 116.4 MMBtu/hr • Equipped with SNCR system to reduce NO_x, and multiclone with ESP to control PM emissions • Equipped with one 30,400 ft^3, 2 hog fuel bins, 2 wood chip fuel bins
U5	One Conveyance System	• 2 Cyclones with combined flow rate of 51.004 scfm • 1 7,118 ft^2 MAC Pulse Jet Baghouse with 300hp Blower • 1 35" x 45" Rotary Airlock • 1 Buhler en-masse, 19", 22tph Conveyor • 2 Each overhead storage bins with enclosed sides
U6	One Spray Unit	• Closed loop unit equipped with integrated, negative pressure, mist collection system and 65' exhaust stack
U7	One Wood Chip Loading Facility	• 1 Platform truck dumper • 1 Wood chip conveying system with dust containment hood • 1 200hp, 59,000CFM Rader blower
U8	Seven De-greasing Tanks	• Non-solvent based
U9	One Gas Storage Tank	• Above ground with 10,000 gallon capacity
U10	One Painting Operation	

PERMIT CONDITIONS

I. PERMIT EXPIRATION

As provided in 40 CFR § 52.21(r), this PSD permit shall become invalid if construction:

A. is not commenced (as defined in 40 CFR § 52.21(b)(9)) within 18 months after the approval takes effect; or

B. is discontinued for a period of 18 months or more; or

C. is not completed within a reasonable time.

II. PERMIT NOTIFICATION REQUIREMENTS

Permittee shall notify EPA Region IX by letter or by electronic mail of the:

A. date construction is commenced, postmarked within 30 days of such date;

B. actual date of initial startup, as defined in 40 CFR § 60.2, postmarked within 15 days of such date;

C. date upon which initial performance tests will commence, in accordance with the provisions of *Conditions X.H and I*, postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the performance test protocol required pursuant to *Conditions X.H and I*; and

D. date upon which initial performance evaluation of the continuous emissions monitoring system (CEMS) will commence in accordance with 40 CFR § 60.13(c), postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the CEMS performance test protocol required pursuant to *Condition X.I.*

III. FACILITY OPERATION

A. At all times, including periods of startup, shutdown, shakedown, and malfunction, Permittee shall, to the extent practicable, maintain and operate the Facility, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to EPA, which may include, but is not limited to, monitoring results, opacity observations, review of operating maintenance procedures and inspection of the Facility.

B. The Permittee shall operate and maintain U1, U2 and U3 in a manner consistent with good engineering practices for its full utilization.

C. As soon as practicable following initial startup of the facility (as defined in 40 CFR § 60.2) but prior to commencement of commercial operation (as defined in 40 CFR § 72.2), and thereafter, the Permittee shall develop and implement an operation and maintenance plan for U1, U2 and U3. At a minimum, the plan shall identify measures for assessing the performance of U1, U2, and U3, the acceptable range of performance measures for achieving the desired output, the methods for monitoring the performance measures, and the routine procedures for maintaining U1, U2 and U3 in good operating condition.

IV. MALFUNCTION REPORTING

A. Permittee shall notify EPA at R9.AEO@epa.gov within two (2) working days following the discovery of any failure of air pollution control equipment or process equipment, or failure of a process to operate in a normal manner, which results in an increase in emissions above the allowable emission limits stated in *Section X* of this permit.

B. In addition, Permittee shall provide an additional notification to EPA in writing or electronic mail within fifteen (15) days of any such failure described under *Condition IV.A.* This notification shall include a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in *Section X*, and the methods utilized to mitigate emissions and restore normal operations.

C. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

V. RIGHT OF ENTRY

The EPA Regional Administrator, and/or an authorized representative, upon the presentation of credentials, shall be permitted:

A. to enter the premises where the Facility is located or where any records are required to be kept under the terms and conditions of this PSD Permit;

B. during normal business hours, to have access to and to copy any records required to be kept under the terms and conditions of this PSD Permit;

C. to inspect any equipment, operation, or method subject to requirements in this PSD Permit; and

D. to sample materials and emissions from the source(s).

VI. TRANSFER OF OWNERSHIP

In the event of any changes in control or ownership of the Facility, this PSD Permit shall be binding on all subsequent owners and operators. Within 14 days of any such change in control or ownership, Permittee shall notify the succeeding owner and operator of the existence of this PSD Permit and its conditions by letter. Permittee shall send a copy of this letter to EPA Region IX within 30 days of its issuance.

VII. SEVERABILITY

The provisions of this PSD Permit are severable, and, if any provision of the PSD Permit is held invalid, the remainder of this PSD Permit shall not be affected.

VIII. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER

ENVIRONMENTAL LAWS

Permittee shall construct the Project in compliance with this PSD permit, the application on which this permit is based, and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

IX. RESERVED

X. SPECIAL CONDITIONS

A. Boiler Annual Emission Limits

Annual emissions, in tons per year (tpy) on a 12-month rolling average basis, shall not exceed the following:

Table 3- U1 Rolling 12-Month Emission Limits

ID	NO_x	CO	PM	PM_{10}	$PM_{2.5}$
U1	267	472	41	41	41

B. Air Pollution Control Equipment and Operation

As soon as practicable following initial startup of U1 (startup as defined in 40 CFR § 60.2) but prior to commencement of commercial operation (as defined in 40 CFR § 72.2), and thereafter, Permittee shall continuously operate, and maintain the following during boiler operations: an SNCR system for control of NO_x, multiclone collectors and an ESP for the control of PM, PM_{10} and $PM_{2.5}$, and good combustion practices for the control of CO. Permittee shall also perform any necessary operations to minimize emissions so that emissions are at or below the emission limits specified in this permit.

Permittee shall also to the extent practicable, maintain and operate equipment in a manner consistent with good air pollution control practice for minimizing emissions.

C. Steam Production and Emission Limitations

1. Except as noted below under *Condition X.D.*, on and after the date of initial startup, Permittee shall not discharge or cause the discharge from U1 into the atmosphere in excess of the following:

Table 4- U1 Short-Term Emission Limits

	U1
NO_x	• 70.2 lbs/hr (3-hour block average) • 0.13 lbs/MMBtu (12-month rolling basis) • 0.15 lbs/ MMBtu (3-hour block average) • EPA Method 1-4 and 7
CO	• 107.7 lbs/hr (3-hour block average) • 0.23 lb/MMBtu (3-hour block average) • EPA Method 1-4 and 10
PM, PM_{10}, $PM_{2.5}$	• 0.02 lb/MMBtu (3-hour block average) • 9.4 lbs/hr (hourly average)

2. CO emissions at all times from U1, including startup and shutdown events as defined *Conditions X.D.3. and X.D.4.*, shall not exceed 432 lbs/hr (hourly average).

3. Steam production from U1 shall not exceed 275,000 lbs/hr (24 hour block average).

4. Visible emissions from U1, except for uncombined water vapor or during periods defined in *Condition X.D.*, shall not exceed 20% opacity in any six minute period, as verified by the continuous opacity monitoring system (COMS).

5. Visible emissions from the U1 shall not exceed 40% opacity for more than three minutes out of any one 60-minute period.

6. At all times, including equipment startup and shutdown, Permittee shall minimize the cause or discharge of the following emissions:
   a. dust from unpaved roads or any other non-vegetation-covered area;
   b. fugitive sawdust from fuel-handling devices and/or storage areas.
   c. char and/or bottom ash which is processed by the char handling systems or removed from U1 by other means.
   d. accumulation of sawdust or ash on outside surfaces including, but not limited to, the main building, U1, ESP, support pads, road areas. Surfaces shall be cleaned on a regular basis to prevent the build-up of ash and/or fugitive dust.
   e. fuel dust or ash spilled due to an upset condition shall be cleaned up in a timely manner. In no event shall spilled dust or ash be allowed to exist beyond 24 hours of the upset.

D. Requirements during Startup and Shutdown

1. Only biomass fuels, as defined in *Condition X.G.1*, and Public Utilities Commission (PUC)-quality pipeline natural gas shall be fired during startup and shutdown

2. For U1, normal operating temperature shall be defined as the normal operating temperature specified by the unit manufacturer.

3. For U1, startup shall be defined as the period beginning with U1 not in operation and concluding when U1 has reached a normal operating temperature. During startup, the generator shall be separated from the electrical grid.

4. For U1, shutdown shall be defined as the period beginning with curtailment of fuel feed and concluding when the recorded superheater outlet temperature reaches 150°F and remains so for at least one hour. During shutdown, the generator shall be separated from the electrical grid.

5. For U1, the duration of startup and shutdown periods and emissions of NO_x, CO, PM, PM_{10} and $PM_{2.5}$ shall not exceed the following, as verified by the CEMS and fuel usage data:

Table 5- U1 Startup and Shutdown Limits

	NO_x (8 hour average)	CO (8 hour average)	PM, PM_{10}, $PM_{2.5}$ (24 hour average)	Duration
Startup	70.2 lb/hr	108 lb/hr	8.93 lb/hr	24 hours
Shutdown	70.2 lb/hr	108 lb/hr	8.93 lb/hr	24 hours

6. For U1, the Permittee must operate the CEMS during startup and shutdown periods.

7. For U1, the Permittee must record the time, date, and duration of each startup and shutdown event.

8. For U1, the Permittee must keep records that include calculations of NO_x, CO, PM, PM_{10}, $PM_{2.5}$ and emissions in lb/hr and lb/MMBtu during each startup and shutdown event based on the CEMS and fuel usage data.

E. Auxiliary Equipment Emissions Limitations

1. Permittee shall not discharge or cause the discharge from each unit into the atmosphere in excess of the following:

Table 6- U2 and U3 Emission Limits

	U2	U3
NO_x		• 0.78 lb/hr
CO		• 4.0 g/hp-hr (3-hour block average) • 6.11 lb/hr
PM/ PM_{10}	• 0.272 lbs/hr (hourly average)	• 0.0216 lb/hr

2. Except during an emergency, U3 shall be limited to operation for maintenance and testing purposes. Annual hours of operation for U3, for maintenance and testing, shall not exceed 100 hours per 12-month rolling average.

F. Operating Conditions and Work Practices

1. *Low SNCR activation temperature* shall be defined as the lowest operating temperature for U1 at which the SNCR system is recommended for operation to reduce NO_x emissions as defined by the SNCR manufacturer. This temperature value shall be included in the operation and maintenance plan required by *Condition III.C.*

2. For U1, SNCR systems for the control of NO_x shall be in operation at all times that U1 exceeds the *low SNCR activation temperature.*

3. For U1, the multiclones and ESP for the control of PM, PM_{10} and $PM_{2.5}$ shall be in operation at all times during the combustion process.

4. U3 shall not operate during startup of U1, except when required for emergency operations.

5. Wood waste collection and storage bin leaks shall be minimized at all times. All identified wood waste collection and storage bin leaks, spills and upsets of any kind shall be corrected or cleaned immediately, within 4 hours, as practicable, to correct the leak, spill or upset.

6. Wood waste collection and storage bins shall be emptied on a schedule that ensures that the cyclone-separator system does not become plugged.

7. Wood waste collection and storage bins, not including the fuel shed, shall remain enclosed to mitigate the fugitive emissions from the unloading process.

8. All ash shall be transported in a wet condition in covered containers or stored in closed containers at all times

9. Fugitive dust generated from access and on-site roads shall be minimized by application of water, dust palliative, chip-sealing, or paving.

10. Fugitive dust from storage piles, processing area, and disturbed areas shall be minimized by periodic cleanup and/or use of sprinklers, tarps, or dust palliative agents.

11. During periods of high winds, Permittee shall take immediate action to correct fugitive dust emissions from the chip processing area.

12. All necessary surfaces shall be cleaned or washed sufficiently to prevent wind-blown dust

from leaving the property boundaries.

13. All truck loading and unloading conducted at the facility shall be done in a manner that minimizes spillage, and fugitive emissions.

14. For U2, the drift rate shall not exceed 0.0005%.

15. Each container holding volatile organic waste shall be labeled with the contents identified and information noting the date when waste material was added.

16. The Permittee shall inspect all containers holding VOCs or waste, at least weekly, for leaks and for deterioration caused by corrosion or other factors.

17. Containers holding ignitable or reactive waste must be located within the property boundary at least 50 feet from the facility's property line.

18. Incompatible wastes must not be placed in the same container. The treatment, storage, and disposal of ignitable or reactive waste, and the commingling of wastes, or wastes and materials, must be conducted so it does not:
    a. Generate extreme heat, pressure, explosion, or violent reaction;
    b. Produce uncontrolled toxic mists, fumes, dusts or gases in sufficient quantities to threaten human health;
    c. Produce flammable fumes or gases in sufficient quantities to pose a risk of fire or explosions;
    d. Damage the structural integrity of the device or facility containing the waste; or
    e. Through other means threaten human health or the environment.

G. Fuel Restrictions

1. The following biomass fuels shall constitute the only fuel allowed for use as fuel in U1, except during periods defined in *Condition X.D.* and to counteract upset conditions:
    a. Untreated wood pallets, crates, dunnage, untreated manufacturing and construction wood debris from urban areas;
    b. All agricultural crops or residues;
    c. Wood and wood wastes identified to follow all of the following practices;
        i. Harvested pursuant to an approved timber management plan prepared in accordance with the Z'berg-Nejedly Forest practice Act of 1973 or other locally or nationally approved plan; and
        ii. Harvested for the purpose of forest fire fuel reduction or forest stand improvement.

2. The heat input from pipeline natural gas shall not exceed 10% of the total heat input to U1 on a 12-month rolling basis.

3. The heat input to U3 shall only be PUC– quality pipeline natural gas

H. Monitoring Conditions

1. For U1, Permittee shall maintain the following equipment at all times when the combustion process is occurring
   a. Permittee shall install, calibrate, operate and quality assure a CEMS that measures CO, NO_x, and CO_2 in ppmv.
   b. Permittee shall conduct initial certification of the CEMS in accordance with *Condition X.H.2.*
   c. Permittee shall operate and maintain a COMS capable of measuring stack gas opacity
   d. Permittee shall install a stack gas volumetric flowrate monitor and steam production rate monitor.

2. The CEMS for U1 shall meet the applicable requirements of 40 CFR Part 60.13 and 40 CFR Part 60 Appendix B, and 40 CFR Part 60 Appendix F, Procedure 1.

3. Each CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute clock-hour period.

4. Data sampling, analyzing, and recording of the CEMS shall also be adequate to demonstrate compliance with emission limits during startup and shutdown.

5. The initial certification of the CEMS may either be conducted separately or as part of the initial performance test of U1. The CEMS must undergo and pass initial performance specification testing on or before the date of the initial performance test.

6. The CEMS shall be audited quarterly and tested annually to demonstrate that it meets the specifications in *Condition X.H.2.* Permittee shall perform a full stack traverse during the initial run of annual relative accuracy test auditing of the CEMS, with testing points selected according to 40 CFR Part 60 Appendix A, Method 1.

7. Permittee shall submit a CEMS performance test protocol to the EPA no later than 30 days prior to the test date to allow review of the test plan and to arrange for an observer to be present at the test. The performance test shall be conducted in accordance with the submitted protocol and any changes required by EPA.

8. For U1, opacity shall be monitored by a COMS that meets the applicable requirements of 40 CFR Part 60 Appendix B, Procedure 1.

9. The COMS shall have a span value of 100% and utilize a computer or other facility which has the capability of interpreting sampling data and producing output to demonstrate compliance with applicable standards. The span value for the continuous

measuring system for measuring opacity shall be between 60 and 80%. The span for the recording instrumentation for the opacity meter shall be 0 to 100%.

10. The operator/owner shall monitor the following combustion and control parameters for U1 on a continuous basis unless otherwise noted:
    a. combustion temperature (at the superheater tube area);
    b. temperature at air heater outlet;
    c. steam production rate;

11. Permittee shall furnish the EPA with a written report of the results of tests within 60 days of completion.

12. Permittee shall continuously monitor the ESP for transformer/rectifier (T/R set) On/Off status and Rapper On/Off status.

13. Permittee shall record hourly readings of ESP zone voltage (minimum 10 kilovolts, maximum 60 kilovolts) and amps on the operator log.

14. For U3, permittee shall install and maintain an operational non-resettable elapsed time meter to record the operating time of the emergency engine.

I. Performance Tests

1. Performance tests shall be conducted in accordance with the test methods set forth in 40 CFR Part 60.8 and 40 CFR Part 60- Appendix A, as modified below:
    a. EPA Methods 1-4, 18 and 25A for VOC emissions. Methods 18 and 25A may both be used simultaneously to quantify the annual emissions of the organic compounds listed in 40 CFR 51.100(s)(1) (using Method 18) and subtract this amount from the annual total VOC emissions (as determined from Method 25A).
    b. EPA Methods 1-4 and 6(c) for SO_2 emissions.
    c. EPA Methods 1-4 and 10 for CO emissions.
    d. EPA Methods 1-4 and 7 for NO_x emissions.
    e. EPA Methods 1-3 and 29 for Pb emissions.
    f. EPA Methods 1-4 and 5 for PM emissions.
    g. EPA Methods 1-4, 5 and 202 with a two-hour test run period for each test for PM_{10} and $PM_{2.5}$ emissions. In lieu of Method 5, the Permittee may use Other Test Method 27. In lieu of Method 202, the Permittee may use Other Test Method 28.
    h. The provisions of 40 CFR Part 60.8(f).
    i. In lieu of the specified test methods, alternative methods may be used with prior written approval from EPA.

2. For U1,
    a. Within 60 days after achieving normal operation, but not later than 120 days after the modification, Permittee shall conduct initial performance tests (as described in 40

CFR Part 60.8) for NO_x CO, PM, PM_{10}, $PM_{2.5}$, VOC, SO_2 and Pb emissions.

b. For performance test purposes, sampling ports, platforms, and access shall be provided on the emission unit exhaust system in accordance with the requirements of 40 CFR Part 60.8(e).
c. Annual performance tests of PM_{10} shall be conducted at the facility's maximum steam production rate.
d. Performance tests for NO_x and CO shall be conducted at least every five years beginning ten years after the initial performance test (within 30 days of the tenth anniversary of the initial performance test date).
e. Permittee shall submit a performance test protocol to EPA no later than 30 days prior to a performance test to allow review of the test plan and to arrange for an observer to be present at the test. The performance test shall be conducted in accordance with the submitted protocol, and any changes required by EPA.

3. For U2, the Permittee shall do the following:
   a. Perform weekly tests of the blow-down water quality using an EPA-approved method. The operator shall maintain a log that contains the date and result of each blow-down water quality test, the water circulation rate at the time of the test, and the resulting mass emission rate. This log shall be maintained onsite for a minimum of five years and shall be provided to EPA and District personnel upon request.
   b. Calculate PM, PM_{10}, and $PM_{2.5}$ emission rate using an EPA-approved calculation based on the total dissolved solids (TDS) and water circulation rate.
   c. Conduct all required cooling tower water quality tests in accordance with an EPA-approved test and emissions calculation protocol. Thirty (30) days prior to the first such test, the operator shall provide a written test and emissions calculation protocol for EPA review and approval, with a copy to the District as specified in *Condition XII*.
   d. Establish a maintenance procedure that states how often and what procedures will be used to ensure the integrity of the drift eliminators and to ensure compliance with recirculation rates. This procedure is to be kept onsite and made available to EPA and District personnel upon request. The permittee shall promptly report any deviations from this procedure.

4. For U3, the Permittee shall conduct an initial performance test (as described in 40 CFR Part 60.4244) for NO_x, CO and emissions and at least every five years beginning ten years after the initial performance test (within 30 days of the tenth anniversary of the initial performance test date).

5. Upon written request from the Permittee, and adequate justification, EPA may waive a specific annual test and/or allow for testing to be done at less than maximum operating capacity.

J. Recordkeeping and Reporting

1. Permittee shall maintain a file of all records, data, measurements, reports, and documents related to the operation of the Facility, including, but not limited to, the following: all records or reports pertaining to adjustments and/or maintenance performed on any system or device at the facility; initial performance test data for U1, documents from the fuel supplier for *Condition X.D.1.*; and all other information required by this permit recorded in a permanent form suitable for inspection.

2. Permittee shall record the efficiency of U1 daily. The heat input, as determined from the U1 efficiency and steam production rate, shall not exceed 468 MMBtu/hr on a monthly basis.

3. For U1, Permittee shall maintain the following records:
   a. The total monthly hours of operation;
   b. 3-hour averages of CO and NO_x emissions in units of lbs/MMBtu and lbs/hour dry basis. All time periods when the boiler is not in operation shall be excluded from the averages. The monthly average of CO and NO_x emissions expressed in lbs/hour shall also be included;
   c. 3-hour average calculations of PM_{10} emissions in units of lbs/MMBtu and lbs/hour dry basis using the most recent annual PM_{10} source test;
   d. notification of all periods the continuous monitors were not functioning and the reasons for the same;
   e. steam production rate averaged over a daily (24-hour) period.

4. Permittee shall maintain CEMS and COMS records that include the following:
   a. the occurrence and duration of any startup, shutdown, or malfunction, performance testing, evaluations, calibrations, checks, adjustments maintenance, duration of any periods during which a CEMS or COMS is inoperative, and corresponding emission measurements.
   b. date, place, and time of measurement or monitoring equipment maintenance activity;
   c. operating conditions at the time of measurement or monitoring equipment maintenance activity;
   d. date, place, name of company or entity that performed the measurement or monitoring equipment maintenance activity and the methods used; and
   e. results of the measurement or monitoring equipment maintenance.

5. Permittee shall maintain records and submit a written report of all excess emissions and opacity measurements to EPA and the District semi-annually, except when more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report is due on the 30th day following the end of each semi-annual period and shall include the following:
   a. Time intervals, data and magnitude of the excess emissions, the nature and cause (if known), corrective actions taken and preventive measures adopted;
   b. Applicable time and date of each period during which the CEMS or COMS was

inoperative (monitor down-time), except for zero and span checks, and the nature of CEMS or COMS repairs or adjustments;

c. A statement in the report of a negative declaration; that is, a statement when no excess emissions occurred or when the CEMS or COMS has not been inoperative, repaired, or adjusted;

d. Any failure to conduct any required source testing, monitoring, or other compliance activities; and

e. Any violation of limitations on operation, including but not limited to restrictions on hours of operation.

6. A period of monitor down-time shall be any unit operating clock hour in which sufficient data are not obtained by the CEMS to validate the hour for NO_x, CO, or CO_2.

7. Excess emissions shall be defined as any period in which emissions exceed the emission limits and standards set forth in *Conditions X.C.1, X.C.2, X.C.3 and X.D.5.*

8. Excess emissions indicated by the CEMS, COMS, source testing, or compliance monitoring shall be considered violations of the applicable emission limit or standard for the purpose of this permit.

9. For U1, daily records of fuel received other than natural gas shall be maintained. These records shall include a detailed description of the fuel supplier, fuel type and tons received.

10. For U3, the permittee shall maintain records of the following: hours of operation, purpose of operation, fuel usage on hourly basis and calculated PM/PM_{10} emissions based on manufacturer emissions specifications and fuel usage data.

11. Unless otherwise specified herein, all records required by this PSD Permit shall be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.

XI. ACROYNMS AND ABBREVIATIONS

ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
BTU	British Thermal Unit
CAA	Clean Air Act
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CTG	Combustion Turbine Generator
CTM	Conditional Test Method
COMS	Continuous Opacity Monitoring System
CU	Cogeneration Unit
District	Shasta County Air Quality Management District
DLN	Dry Low NO_X
(d)scf	(dry) Standard Cubic Feet
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
gpm	Gallons Per Minute
gr	Grains
HHV	Higher Heating Value
hr	Hour
lbs	Pounds
MMBtu	Million British Thermal Units
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NO_2	Nitrogen Dioxide
NO_X	Oxides of Nitrogen
NSPS	New Source Performance Standards
PM	Total Particulate Matter
$PM_{2.5}$	Particulate Matter with aerodynamic diameter less than 2.5 micrometers
PM_{10}	Particulate Matter with aerodynamic diameter less than 10 micrometers
ppm	Parts Per Million
ppmvd	Parts Per Million by Volume, Dry basis
ppmv	Parts Per Million by Volume
PSD	Prevention of Significant Deterioration
RATA	Relative Accuracy Test Audit
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SO_X	Oxides of Sulfur
TDS	Total Dissolved Solids
tpy	Tons Per Year
yr	Year

XII. AGENCY NOTIFICATIONS

All correspondence as required by this Approval to Construct must be sent to:

A. Director, Air Division (Attn: AIR-5)
EPA Region IX
75 Hawthorne Street
San Francisco, CA 94105-3901

Email: R9.AEO@epa.gov
Fax: (415) 947-3579

With a copy to:

B. Air Pollution Control Officer
Shasta County Air Quality Management District
1855 Placer Street, Suite 101
Redding, CA 96001
Fax: (661) 723-3450

Excerpt 2

SPI Anderson Ambient Air Quality Impact Report, dated September 12, 2012 (“AAQIR”), AR III.02

U.S. ENVIRONMENTAL PROTECTION AGENCY
REGION IX

STATEMENT OF BASIS AND AMBIENT AIR QUALITY IMPACT REPORT

For a Clean Air Act
Prevention of Significant Deterioration Permit

Sierra Pacific Industries-Anderson
PSD Permit Number SAC 12-01

September 2012

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PROPOSED PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
SPI - Anderson
Statement of Basis and Ambient Air Quality Impact Report
(PSD Permit SAC 12-01)

Table of Contents

Acronyms & Abbreviations

AAQIR	Ambient Air Quality Impact Report
ACC	Air Cooled Condenser
Act	Clean Air Act [42 U.S.C. Section 7401 et seq.]
Agency	U.S. Environmental protection Agency
AQRV	Air Quality Related Value
BACT	Best Available Control Technology
BDT	Bone Dry Tons
BTU	British thermal units
CAA	Clean Air Act [42 U.S.C. Section 7401 et seq.]
CBI	Confidential Business Information
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
EPA	U.S. Environmental protection Agency
ESA	Endangered Species Act
FLM	Federal Land Manager
FWS	U.S. Fish and Wildlife Service
GAQM	40 CFR part 51, Appendix W- *Guideline on Air Quality Models*
GEP	Good engineering practice
hp	Horsepower
HRSG	Heat Recovery Steam Generator
kW	kilowatt
m	meter
MMBTU	Million British thermal units
MW	Megawatts of electrical power
NAAQS	National Ambient Air Quality Standards
NLCD92	USGS 1992 National Land Cover
NO	Nitrogen oxide or nitric oxide
NO_2	Nitrogen dioxide
NO_x	Oxides of Nitrogen (NO + NO_2)
NP	National park
NSPS	New Source performance Standards, 40 CFR part 60
NSR	New Source Review
PM	Total particulate Matter
$PM_{2.5}$	Particulate Matter less than 2.5 micrometers (μm) in diameter
PM_{10}	Particulate Matter less than 10 micrometers (μm) in diameter
ppb	parts per billion
ppm	parts per million
PSD	Prevention of Significant Deterioration
PTE	potential to emit
RBLC	U.S. EPA RACT/BACT/LAER Information Clearinghouse
SCAQMD	Shasta County Air Quality Management District

SCFM	Standard Cubic Feet per Minute
SIA	Significant Impact Area
SIL	Significant Impact Level
SO_2	Sulfur Dioxide
SO_x	Oxides of Sulfur
SPI	Sierra pacific Industries
tpy	tons per year
USGS	United States Geological Survey
WA	Wilderness Area

Proposed Prevention of Significant Deterioration (PSD) Permit Statement of Basis and Ambient Air Quality Impact Report

SPI- Anderson

Executive Summary

Sierra Pacific Industries (SPI) has applied for an approval to construct a new cogeneration unit capable of generating approximately 31 megawatts (MW) of electricity by combusting clean cellulosic biomass during normal operation and natural gas for startup and shutdown. The cogeneration unit will be constructed within the physical boundaries of the current SPI- Anderson Division facility location. The facility is located at 19758 Riverside Avenue in Anderson, California 96007 (Assessor's parcel No. 050-110-025). The proposed major Prevention of Significant Deterioration (PSD) permit modification is consistent with the requirements of the PSD program for the following reasons:

- The proposed permit requires the Best Available Control Technology (BACT) for Oxides of Nitrogen (NO_x), Carbon Monoxide (CO), Total Particulate Matter (PM), Particulate Matter under 10 micrometers (μm) in diameter (PM_{10}) and Particulate Matter under 2.5 μm in diameter ($PM_{2.5}$);

- The proposed emission limits will protect the National Ambient Air Quality Standards (NAAQS) for NO_2, CO, PM_{10} and $PM_{2.5}$. There is no NAAQS set for Total Particulate Matter (PM);

- The facility will not adversely impact soils and vegetation, or air quality, visibility, and deposition in Class I areas, which are parks or wilderness areas given special protection under the Clean Air Act (CAA);

- After informal consultation with the U.S. Fish and Wildlife Service under Section 7 of the Endangered Species Act, EPA has concluded that the proposed modification will have no likely adverse effect on any Federally-listed endangered or threatened species or designated critical habitat in the project's impact area.

1. Purpose of this Document

This document serves as the Statement of Basis and Ambient Air Quality Impact Report for the proposed PSD permit modification for the SPI– Anderson facility. This document describes the legal and factual basis for the proposed permit, including requirements under the PSD regulations at Title 40 of the Code of Federal Regulations (CFR) §52.21. This document also serves as the fact sheet to meet the requirements of 40 CFR Part 124.7 and 124.8.

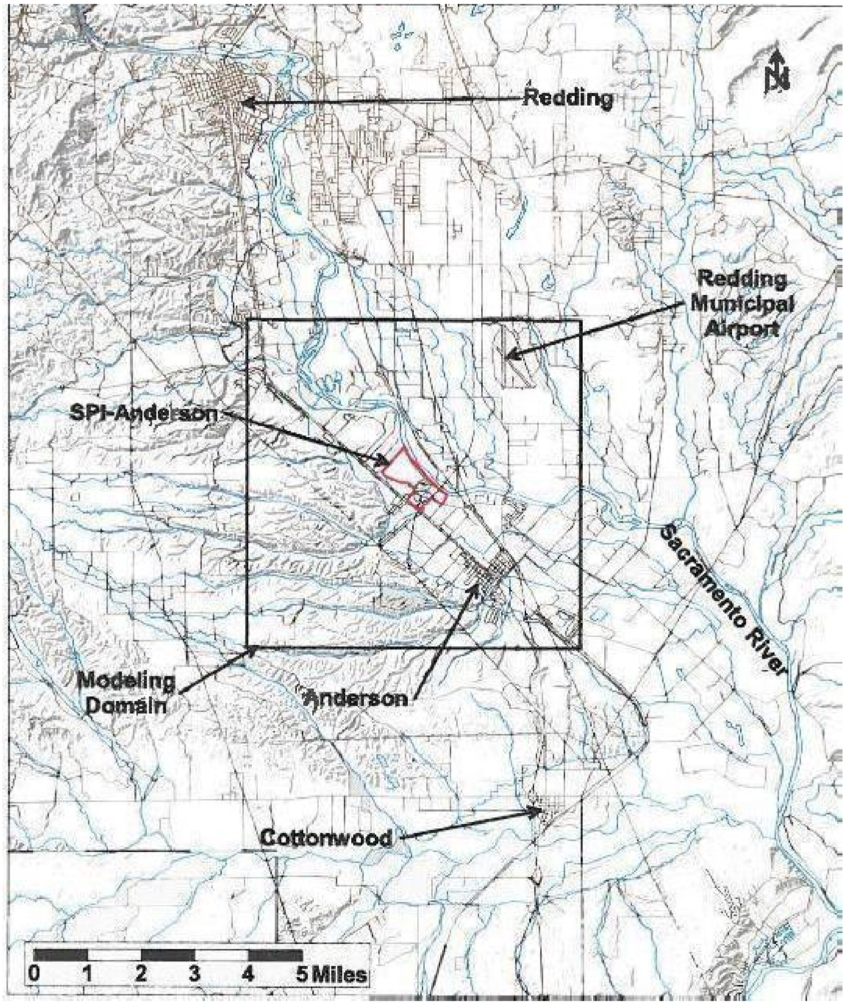
2. Applicant

Sierra Pacific Industries
P.O. Box 496028
Redding, CA 96049-6028

3. Project Location

The proposed location for the modification of the SPI- Anderson facility will be within the physical footprint of the current facility location. The facility is located at 19758 Riverside Avenue in Anderson, California 96007 (Assessor's parcel No. 050-110-025). The site is approximately 0.5 mile west of Interstate 5, and approximately 2 miles north of the city of Anderson. The facility is bordered on the northeast by the Sacramento River, on the northwest by a private parcel, on the southwest by Union Pacific Railroad tracks and State Route (SR) 273, and on the southeast by private parcels. The city of Anderson is located within the jurisdiction of the Shasta County Air Quality Management District (SCAQMD).

The map on the following page shows the approximate location of SPI- Anderson.



4. Project Description

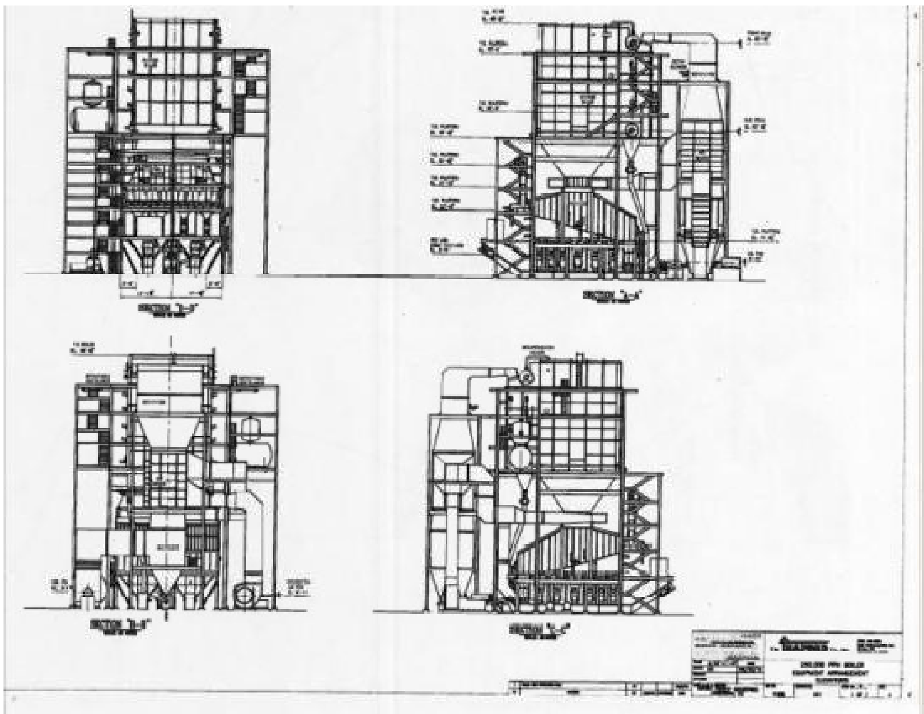
SPI has applied for an approval to construct and operate a new cogeneration unit capable of generating 31 MW of gross electrical output from the combustion of clean cellulosic biomass and natural gas.

The original PSD permit for this lumber manufacturing facility was issued in 1994 by the Shasta County Air Quality Management District (SCAQMD). The site currently contains a wood-fired boiler with associated air pollution control equipment and conveyance systems that produces steam to dry lumber in existing kilns. On March 3, 2003 USEPA revoked and rescinded SCAQMD's authority to issue and modify federal PSD permits for new and modified major sources of attainment pollutants in Shasta County. Therefore, EPA is modifying the PSD permit issued by SCAQMD to incorporate the proposed modifications.

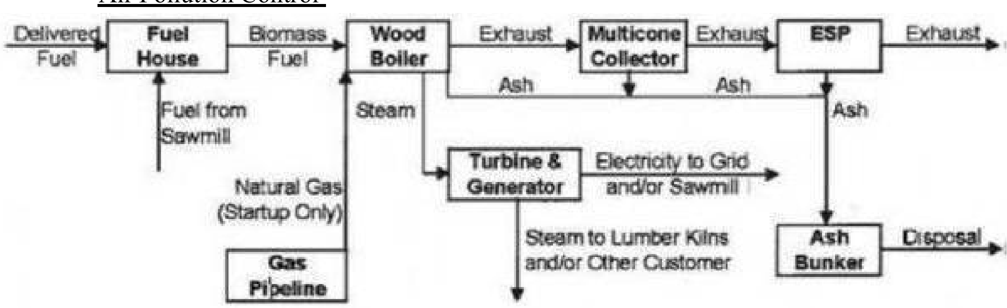
A new cogeneration unit equipped with a stoker boiler is being proposed in order to burn additional clean cellulosic biomass fuel. Fuel will be generated on site from the lumber operations and delivered from other fuel sources to produce roughly 250,000 pounds per hour of steam. This steam be used to dry lumber in existing kilns for the lumber operation, as well as feed a turbine that will drive a generator to produce electricity for use on site or for sale to the electrical grid. A closed-loop two-cell cooling tower will be used to dispose of waste heat from the steam turbine.

Currently, the Anderson lumber operation produces approximately 160,000 bone dry tons (BDT) of wood waste per year. Approximately 60,000 BDT are consumed by the existing cogeneration unit, 20,000 BDT are trucked to other biomass power plants, and the roughly 80,000 BDT balance is trucked to other markets (e.g. wood chips to pulp mills). The new proposed boiler will have the capacity to consume a maximum of 219,000 BDT per year. Roughly 80,000 BDT will be generated by the facility's existing lumber operations at its current output, additional wood fuel will be transported by truck to the facility from SPI's other lumber operations in California.

The following page contains a design draft and a simplified process flow diagram for the proposed boiler.



Air Pollution Control



SPI- Anderson will employ several air pollution control alternatives to reduce the emissions of some criteria pollutants from the proposed new boiler. Selective Non-catalytic Reduction (SNCR) will be used to reduce NO_x emissions. Ammonia will be introduced into the furnace at the appropriate temperature window in order to most effectively decrease NO_x emissions. To reduce particulate matter (PM) emissions, SPI will use an electrostatic precipitator (ESP) preceded by a multiclone.

Permitted Equipment

Table 4-1 lists the proposed new equipment that will be regulated by this PSD permit:

Table 4-1: Proposed New Equipment List

Stoker Boiler with Vibrating Grate	• Biomass-fired with natural gas burners for start-up and shutdown • Maximum annual average heat input of 468 MMBtu/hr and steam generation rate of 250,000 lbs/hr • Equipped with two natural gas burners, each with a maximum rated heat input of 62.5 MMBtu/hr • Equipped with SNCR system to reduce nitrogen oxides, and multiclone with ESP to control PM emissions
Emergency Engine	• 256 hp at 1,800 rpm • Used to run the emergency boiler recirculation pump • Natural-gas fired
Cooling Tower	• Composed of two-cells with an expected water load of 4.24 gallons per minute per square foot.

Table 4-2 lists the existing equipment that is not included in this PSD permit. The equipment listed below is permitted by SCAQMD, and Table 4-2 is provided for reference purposes only.

Table 4-2: Existing Equipment List

Wellons Stoker Boiler	• Biomass-fired with natural gas burners for start-up • Maximum annual average heat input of approximately 116.4 MMBtu/hr • Equipped with SNCR system to reduce nitrogen oxides, and multiclone with ESP to control PM emissions • Equipped with one 30,400 ft^3 fuel storage bin, 2 hog fuel bins, 2 wood chip fuel bins
Conveyance System	• 2 Cyclones with combined flow rate of 51.004 scfm • 1 7,118 ft^2 MAC pulse Jet Baghouse with 300hp Blower • 1 35" x 45" Rotary Airlock • 1 Buhler en-masse, 19", 22tph Conveyor • 2 Overhead Storage Bins with enclosed sides
Spray Unit	• Closed loop unit equipped with integrated, negative pressure, mist collection system and 65' exhaust stack
Wood Chip Loading Facility	• 1 platform truck dumper • 1 Wood chip conveying system with dust containment hood • 1 200 hp Rader blower
7 De-greasing Tanks	• Non-solvent based
Gasoline Storage Tank	• Above ground with 10,000 gallon capacity
Painting Operation	

5. Emissions from the Proposed Project

The PSD program is intended to protect air quality in "attainment areas", which are areas that meet the National Ambient Air Quality Standards (NAAQS). Table 5-1 describes which pollutants are covered by the PSD program within the SCAQMD. The U.S. EPA is responsible for issuing PSD permits for pollutants in attainment with the NAAQS in the SCAQMD. As illustrated in Table 5-1, SCAQMD is attainment/ unclassifiable for each NAAQS,

Table 5-1: NAAQS Attainment Status for SCAQMD

Pollutant	Attainment Status	Permit program
Lead (Pb)	Attainment	PSD
Nitrogen Dioxide (NO_2)	Attainment	PSD
Sulfur Dioxide (SO_2)	Attainment	PSD
Carbon Monoxide (CO)	Attainment	PSD
Sulfuric Acid Mist (H_2SO_4)	n/a[1]	PSD
Particulate Matter (PM)	n/a[1]	PSD
Particulate Matter under 2.5 micrometers diameter ($PM_{2.5}$)	Attainment	PSD
Particulate matter under 10 micrometers diameter (PM_{10})	Attainment	PSD
Ozone	Attainment	PSD
Greenhouse Gases (GHG)	n/a[1]	PSD

The PSD program (40 CFR 52.21) applies to "major" new sources of attainment pollutants or "major modifications" at existing major sources of attainment pollutants. SPI- Anderson is an existing PSD major source proposing to modify its existing PSD permit in order to construct the equipment detailed in Table 4-1.

6. Applicability of the Prevention of Significant Deterioration Regulations

The estimated emissions in Table 4 shows that the proposed construction will be a major modification for NO_x, CO, PM, PM_{10} and $PM_{2.5}$. The annual emission data in Table 6-1 are based on the applicant's maximum expected emissions, including emissions from startup and shutdown cycles. The applicant assumes that all emissions of PM are of diameter less than 2.5 microns ($PM_{2.5}$), which is a conservative estimate as some particulate emissions may be much larger than 2.5 micrometers in diameter.

Once a modification to an existing major stationary source is considered a major modification for a PSD pollutant, PSD also applies to any other regulated pollutant that is emitted in a significant amount. For our PSD applicability determination we are conservatively assuming that all sulfur oxide emissions are sulfur dioxide (SO_2). The data in Table 6-1 show that emissions of SO_2, volatile organic compounds (VOC), sulfuric acid (H_2SO_4) and lead (Pb) will be less than the significant emission rate. Therefore, PSD does not apply for SO_2, VOC, H_2SO_4 and Pb. Total estimated emissions of the PSD-regulated pollutants resulting from the emission units in this modification are listed in Table 6-1.

[1] There is no national ambient air quality standard (NAAQS) for PM, H_2SO_4 or GHG. However, in addition to other pollutants for which no NAAQS have been set, PM, H_2SO_4 and GHG are listed as regulated pollutants with a defined applicability threshold under the PSD regulations (40 CFR 52.21).

Table 6-1: Estimated Emissions and BACT Applicability[2]

Pollutant	Estimated Annual Emissions (tpy)	Significant Emission Rate (tpy)	Does BACT apply?
CO	472	100	Yes
NO_x	267	40	Yes
PM	42.1	25	Yes
PM_{10}	42.1	15	Yes
$PM_{2.5}$	42.1	10	Yes
VOC	34.9	40	No
SO_2	10.3	40	No
H_2SO_4	4.2	7	No
Lead	0.03	0.6	No
CO_2e	420,137 (Total) 38,379 (nondeferred)	CO2e: 75,000 (subject to regulation) Mass: 0 (significant)	No[3]

7. Best Available Control Technology

This chapter describes the Best Available Control Technology (BACT) for the control of CO, NO_x, PM, PM_{10} and $PM_{2.5}$ emissions from this facility. Section 169(3) of the CAA defines BACT as follows:

> "The term 'best available control technology' means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under the Clean Air Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (NSPS) or 112 (NESHAPS) of the Clean Air Act."

[2] Annual emissions estimates differ from the PSD Application submission by SPI and Environ. EPA calculated annual emissions estimates at worst case annual heat input of 468 MMBtu/hr, not 425 MMBtu/hr, and the CO BACT limit was revised to 0.23 lb/MMBtu. (See SPI Annual Emissions Memo to file)

[3] Although the proposed modification identifies an increase in GHG emissions that exceeds the "subject to regulation" threshold of 75,000 tpy CO_2e and GHG significance rate of 0 tpy, EPA's *Deferral for CO_2 emissions from Bioenergy and Other Biogenic Sources under the Prevention of Significant Deterioration and Title V programs* (76 FR 43490 July 20, 2011) applies to this project. Since the non-deferred GHG emissions for this project are 38,252 tpy CO_2e, the modification is not subject to BACT for GHG. See Appendix A for relevant emissions calculations and further discussion.

In accordance with 40 CFR 52.21(j), a new major stationary source is required to apply BACT for each regulated NSR pollutant for which its PTE exceeds significance thresholds. BACT is defined as "an emission limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under the Act ... which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable for such source." BACT must be at least as stringent as any applicable New Source Performance Standards (NSPS) under 40 CFR Part 60 or National Emission Standard for Hazardous Air Pollutants (NESHAP) under 40 CFR Part 61. EPA outlines the process it will use to do this case-by-case analysis (referred to as "top-down" BACT analysis) in a June 13, 1989 memorandum. The top-down BACT analysis is a well established procedure that the Environmental Appeals Board (EAB) has consistently followed in adjudicating PSD permit appeals. See, e.g., In re Knauf, 8 E.A.D. 121, 129-31 (EAB 1999); In re Maui Electric, 8 E.A.D. 1, 5-6 (EAB 1998).

In brief, the top-down process requires that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent technology. That technology is established as BACT unless it is demonstrated that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not achievable for the case at hand. If the most stringent technology is eliminated, then the next most stringent option is evaluated until BACT is determined. The top-down BACT analysis is a case-by-case exercise for the particular source under evaluation. In summary, the five steps involved in a top-down BACT evaluation are:

1. Identify all available control options with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;

2. Eliminate technically infeasible technology options;

3. Rank remaining control technologies by control effectiveness;

4. Evaluate the most effective control alternative and document results; if top option is not selected as BACT, evaluate next most effective control option; and

5. Select BACT, which will be the most stringent technology not rejected based on technical, energy, environmental, and economic considerations.

BACT is required for NO_x, CO, PM, PM_{10}, and $PM_{2.5}$ for the new proposed emission units. Table 7-1 lists the BACT determinations for NO_x, CO, PM, PM_{10}, and $PM_{2.5}$ from the proposed boiler and emergency engine, and PM, PM_{10}, and $PM_{2.5}$ from the cooling tower. For the purposes of this determination, all NO_x emissions will be treated as NO_2.

Table 7-1: Summary of BACT Limits[4]

Unit	NO_x	CO	PM	PM_{10}	$PM_{2.5}$
Boiler (468 MMBtu/hr)	0.15 lb/MMBtu (3-hour block average) 0.13 lb/MMBtu (12-month rolling average)	0.23lb/MMBtu (3-hour block average)	0.02 lb/MMBtu (3-hour block average)	0.02 lb/MMBtu (3-hour block average)	0.02 lb/MMBtu (3-hour block average)
Emergency Engine (256 hp)	0.8 lb/hr (hourly average)	6.11 lb/hr (hourly average)	0.03 lb/hr (hourly average)	0.03 lb/hr (hourly average)	0.03 lb/hr (hourly average)
Cooling tower	n/a	n/a	0.251 lb/hr, (hourly average)	0.251 lb/hr, (hourly average)	0.251 lb/hr (hourly average)

7.1. BACT for a New Boiler at a Lumber Facility

The SPI- Anderson facility will install and operate a new boiler to support lumber operations at the sawmill and to sell electricity to the grid. The new boiler will have a maximum heat input capacity of 468 MMBtu/hr. The boiler is subject to BACT for NO_x, CO, PM, PM_{10}, and $PM_{2.5}$. A top-down BACT analysis for each pollutant has been performed and is summarized below.

7.1.1. Oxides of Nitrogen

NO_x is formed at high temperatures during combustion when nitrogen in the combustion air or bound in the fuel combines with oxygen to form NO. Depending on conditions in the exhaust stream, some portion of the NO will react to form NO_2. For the purposes of this analysis and the permit, all NO_x is assumed to form NO_2.

Step 1 - Identify All Control Technologies

A number of existing boiler designs support the combustion of biomass for purpose of electricity generation of this megawatt capacity. Therefore, in identifying all possible control technologies, the BACT analysis will initially begin with the discussion of two boiler design alternatives.

A significant distinction in boiler design for this purpose can be characterized by the biomass combustion process that occurs within the boiler's combustion chamber. Biomass boilers can be classified as either being stoker or fluidized bed. *Stoker boiler* means a boiler unit consisting of a mechanically operated fuel-feeding mechanism which includes a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. *Fluidized bed boiler* means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler. *Fluidized bed combustion* means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.

Boiler design technologies include, but are not limited to, the following:

[4] SPI- Anderson must keep all records of all testing, fuel use, and fuel testing requirements for a period of five (5) years and must report excess emissions to EPA on a semiannual basis.

- Stoker- including vibrating, traveling grate, etc.
- Fluidized bed- including pressurized or atmospheric, such as bubbling bed, circulating, etc.

In addition to the boiler design, the available inherent NO_x control technology includes:

- Good combustion practices

In addition to the inherent available control technology, the add-on NO_x control technologies include:

- Dry Low-NO_x burner (DLN)
- Selective non-catalytic reduction (SNCR)
- Selective Catalytic Reduction (SCR)
- Regenerative SCR (RSCR)
- SCR Variants
- EMxTM system (formerly SCONOx)

Step 2 – Eliminate Technically Infeasible Options

Boiler Design Alternatives

For the proposed boiler to service SPI- Anderson's existing primary lumber business and consume the wood from SPI's other locations, the proposed boiler design must be able to reliably operate under various conditions. Furthermore, SPI has not entered a binding power purchasing agreement with consistent base load electricity demand. With daily variations in renewable energy demand and the sawmill's steam requirements, the new boiler at the Anderson facility may have to vary steam production between 20% and 100% of full load capacity. If electricity demand decreases or the turbine and/or generator malfunction, the boiler may need to significantly reduce the amount of steam it generates.

However, periods of reduced steam demand do not necessarily coincide with reduced sawmill requirements. If other pieces of the cogeneration unit are not operating, and the boiler cannot reduce steam output, then the boiler must be shut down, rendering some of the lumber-drying kilns inoperable. If the kilns are unable to operate, lumber cannot be dried and the existing lumber facility may be unable to function normally. Moreover, as the modification will not expand beyond the current physical footprint of the SPI-Anderson facility, the space for stockpiling wood may be exhausted while the kilns are inoperable, thus causing portions of the sawmill to be shut down. Therefore, any boiler chosen for the proposed modification must reliably function at low steam-load conditions in order to accommodate SPI- Anderson's existing lumber operation.

The proposed boiler at the SPI- Anderson facility must be guaranteed to reliably operate at steam loads ranging from 50,000 lbs/hr to 250,000 lbs/hr. This variability in projected steam output is also caused by uncertainty in biomass fuel moisture and the variety of wood products and trimmings produced by SPI's other nearby facilities. As Environ, SPI's project consultant, stated in its January 23, 2012 letter[5], "…several examples of

[5] Albright, Eric "Supplemental Control Technology Analysis Sierra Pacific Industries Biomass-Fired Cogeneration Project Anderson, California" Letter to Gerardo Rios. 23 Jan. 2012

biomass-fired fluidized-bed boilers [are] in operation. However, most, if not all, produce steam solely for power generation, and do not provide process steam. Steam used to heat industrial processes is often subject to varying demand, especially for batch processes (e.g., lumber dry kilns). The primary reason for fluidized bed boiler designs lack of representation among biomass-fired process steam generators is the inability to operate in a turndown mode." The process steam flexibility that SPI desires for its sawmill operations cannot reliably or effectively be accommodated by a fluidized bed boiler. Therefore, a fluidized bed boiler is technically infeasible for this project.

EMxTM

To date, EMxTM has been designed and used only on small to medium sized natural gas-fired stationary turbines for demonstration purposes. We are not aware of any biomass boiler applications currently operating with EMx, or any permit application for a biomass boiler that proposes to use the EMx to control NO_x emissions.

The EMxTM system is sensitive to sulfur in the exhaust, which can degrade the performance of the system. While wood fuels are not generally considered high-sulfur fuels, the AP-42 SO_2 emission factor for wood-fired boilers is 0.025 lb/MMBtu, which is equivalent to about 7.2 lb/hr of SO_2. Natural gas, the combustion fuel most commonly associated with EMxTM applications, has maximum sulfur limit of one grain per 100 standard cubic feet (gr/scf) of gas in California, where EMxTM has been applied. On a heat input basis, this is equivalent to an SO_2 emission rate of 0.43 lb/hr.

The lack EMx implementation for biomass boilers, combined with the sensitivity to sulfur suggest that EMxTM is technologically infeasible as a control technology for controlling NO_x emissions from a biomass-fired boiler. Therefore we do not consider this technology achievable for biomass-fired boilers at this time.

DLN Burner

With two or more DLN burners, the biomass combustion fuel would need to be pulverized and burned in suspension using wall-mounted burners. This presents a significant departure from SPI's proposed boiler design where combustion occurs on a moving grate. DLN burners are designed to limit the amount of fuel-bound nitrogen that is converted to NO_x during combustion, and are generally suited to boilers that burn wood waste containing a high percentage of resins, such as the waste from medium density fiberboard, plywood, or veneer operations. The emission rate with DLN burners is projected to be 0.35 lb/MMBtu.

Good combustion practices

A modern biomass-fired boiler furnace, operated with computerized controls to ensure good combustion practices would result in a NO_x emission limit between 0.20 lb/MMBtu and 0.26 lb/MMBtu. The boiler design proposed by SPI would emit 0.20 lb/MMBtu when utilizing only good combustion practices to reduce NO_x emissions. Good combustion practices are the result of proper boiler maintenance and design.

All of the listed add-on technologies described below are technically feasible for the proposed project.

SNCR (Selective Non-Catalytic Reduction)
With SNCR, ammonia is injected through ammonia-injection nozzles which are positioned in the furnace and used at relatively high temperatures to promote the reaction of NO_x with ammonia. SNCR systems are often incorporated into the overall boiler design, and can be located at the furnace exit because they do not rely on a catalyst. Catalysts may be problematic for biomass stokers because catalyst beds are susceptible to plugging from PM in the flue gases. SNCR is a commonly-employed add-on NO_x control technology for biomass-fired boilers. Over a long term basis the emission rate from a design utilizing an SNCR system is projected to be 0.13 lb/MMBtu of NO_x.

SCR (Selective Catalytic Reduction), RSCR (Regenerative Selective Catalytic Reduction) and other catalyst variants
An SCR system is similar to SNCR in that a reagent reacts with NO_x to form nitrogen and water; however a catalyst matrix is used to allow the reduction reaction to take place at lower temperatures. There are several SCR and SCR variant systems that have been permitted for use on biomass boilers in various configurations along the exhaust stream. Although many biomass boilers have begun to be permitted with SCR and SCR variant systems, the verifiable data and the demonstrated effectiveness of SCR systems at constructed biomass facilities remains limited. Moreover, the projected NO_x emissions from those facilities permitted with SCR vary considerably.

The RBLC contains references to permitted RSCR and SCR systems with emission limits as low as 0.03 lb/MMBtu of NO_x on a 12-month rolling basis as seen in Table 7.1-1. The lowest referenced NO_x emissions limit that EPA has discovered in its review from constructed biomass power plants is McNeil Generating Station with a verified 2010 quarterly calendar emission rate of 0.75 lb/MMBtu of NO_x. However, the short term emission limit for the main boiler at McNeil while burning wood shall not exceed 0.23 lb/MMBtu. The installation of that SCR system was permitted through a permit amendment. The facility "proposed to install and operate a selective catalytic reduction (SCR) system in order to reduce the facility's emissions of NO_x. The reduced NO_x emissions are required for the Facility to qualify for Class 1 renewable energy credits (RECs) in New England."[6] Aspen Power's Lufkin Generating Station in Texas has constructed, however, EPA has not been able to verify if this NO_x emissions limit has been demonstrated in practice over the shorter averaging period.

Step 3 – Rank Control Technologies
A summary of recent NO_x BACT determinations for biomass-fired boilers is provided in Table 7.1-1. The applicant has proposed a NO_x limit of 0.13 lb/MMBtu, based on a 12-month rolling average and 0.15 lb/MMBtu, based on a 3-hour block average.

6 McNeil Generating Station Title V Permit

Table 7.1-1: Summary of Recent NO_x BACT Determinations for Similar Units

Facility Name	State	Permit#	Permit Date	Control Method	Limit		Average	Status
Beaver Wood Energy Fair Haven	VT	AP-11-015	10-Feb-12	SCR	0.05	lb/MMBtu	12 month rolling	Not Constructed
Berlin Biopower	NH	TP-0054	26-Jul-10	SCR	0.06	lb/MMBtu	30 day rolling	Project Canceled
Montville Power	CT	[illegible]	[illegible]	RSCR	[illegible]	lb/MMBtu	[illegible]	Not Constructed
Clean Power Berlin	NH	TP-0033	25-Sep-09	SCR	0.065	lb/MMBtu	30 day rolling	Not Constructed
Concord Steam	NH	TP-0014	12-Aug-11	SCR	0.065	lb/MMBtu	30 day rolling	Not Constructed
McNeil Generating Station*	VT	AOP 07 023	2 Feb 09	RSCR	0.075	lb/MMBtu	Quarterly	Verified
Lufkin Generating Plant	TX	81706	26 Oct 09	SCR	0.075	lb/MMBtu	30 day rolling	Constructed
Warren County Biomass	GA	4911-301-0016-P-01-0	17-Dec-10	SNCR	0.1	lb/MMBtu	30 day rolling	Not Constructed
Darrington Energy Cogeneration	WA	PSD 03 04	11 Feb 05	SNCR	0.12	lb/MMBtu	24 hour block	Not Constructed
SPI-Anderson	**CA**	**SAC 12-01**	**Proposed**	**SNCR**	**0.13**	**lb/MMBtu**	**12 month rolling**	
SPI Skagit County Lumber Mill	WA	PSD 05 04	11 Jun 09	SNCR	0.13	lb/MMBtu	24 hr block	
Clewiston Sugar Mill	FL	PSD FL 333	18 Nov 03	SNCR	0.14	lb/MMBtu	30 day rolling	
SPI-Anderson	**CA**	**SAC 12-01**	**Proposed**	**SNCR**	**0.15**	**lb/MMBtu**	**3 hour block**	
SPI Aberdeen	WA	PSD-02-02	17-Oct-02	SNCR	0.15	lb/MMBtu	24 hour block	
Lindale Renewable Energy	TX	PSDTX1104	8-Jan-10	SNCR	0.15	lb/MMBtu	30 day rolling	
Fibrominn Biomass Power	MN	15100038-001	23-Oct-02	SNCR	0.16	lb/MMBtu	30 day rolling	
Koda Energy	MN	13900114	23-Aug-07	SNCR	0.25	lb/MMBtu	Not specified	

* McNeil Station is not the result of a BACT Determination as discussed in NO_x Step 4 below.

The remaining technologically feasible control technologies ranked in decreasing order of effectiveness are:

Table 7.1-2: Ranking of NO_x control technologies

NO_x control technology	Emission Rate (lb NO_x /MMBtu)
SCR, RSCR and variants	0.06
SNCR	0.13
Good combustion practices	0.20
DLN burner	0.35

Step 4 – Economic, Energy and Environmental Impacts

SPI has submitted cost-effectiveness estimates comparing SCR and SNCR with their projected NO_x emission rates and the cost of installation and operation of the respective control technologies. SPI assumed that the new boiler's emission rate with the use of SCR for the cost-effectiveness estimates would be lower than any emissions level that EPA has found to be demonstrated in practice. SPI presumes that the rate of NO_x emissions with SCR and SNCR are 0.06 lb/MMBtu and 0.13 lb/MMBtu respectively.

The average cost per ton controlled from SCR and SNCR technologies at the proposed emission levels are $4,596 and $1,417 respectively. However, the incremental cost-effectiveness separating the two technologies reveals that the cost of each additional ton of NO_x removed by the implementation of SCR at the projected cost and emission rate is $9,191. EPA reviewed the cost estimates provided in the PSD permit modification application and determined that it considered the appropriate operation and capital costs but calculated improper potential to emit emissions estimates. The additional expense of the SCR equipment is due to a higher capital cost in primary equipment along with higher operational, maintenance and lost revenue costs.

Although the McNeil Generating Station has demonstrated a lower NO_x emission limit on a calendar quarterly basis, it has a short term NO_x emission limit of 0.23 lb/MMBtu. Moreover, the possible economic incentives of the Class 1 Renewable Energy Credits in New England are difficult to quantify and not available to SPI- Anderson. This may allow SCR system to be more economically feasible for McNeil Generating Station and other proposed systems in the New England area than for SPI- Anderson in California.

EPA does not anticipate additional significant environmental or energy impacts from employing the SNCR or SCR technology. Both systems use ammonia as a reagent: anhydrous ammonia, aqueous ammonia, or urea mixed with water (which hydrolyzes in the hot exhaust to form ammonia). In the case of aqueous ammonia or urea mixed with water, additional fuel must be combusted to evaporate the water associated with the reagent. Moreover, energy is required to operate the injectors used by either technology to introduce the reagent into the exhaust. With either technology, the exhaust leaving the boiler stack will contain some small quantity of ammonia.

Step 5 – Select BACT

SPI has proposed the most stringent NO_x emissions limit for stoker boilers with SNCR demonstrated in practice. Although additional tons of possible NOx emissions may be controlled by the installation of an SCR system, the increased annual costs of an SCR system or other variants versus the SNCR system is cost prohibitive at this existing sawmill facility.

Based on a review of the available control technologies for NO_x emissions from biomass boilers selected for this operation, we have concluded that BACT for the stoker boiler to perform this purpose is 0.15 lb/MMBtu (3-hour block average) and 0.13 lb/MMBtu (12-month rolling average) employing SNCR. We are also requiring a lb/hr mass emission rate of 60.8 lb/hr (3-hour block average) during normal operations.

7.1.2. Carbon Monoxide

Carbon monoxide (CO) occurs due to incomplete combustion of fuel in the boiler's combustion chamber, and in the Low-NO_x burners when they are operated.

Step 1 - Identify All Control Technologies

A number of existing boiler design alternatives support the combustion of biomass at this megawatt capacity. Therefore, in identifying all possible control technologies, the BACT analysis should begin with a discussion of boiler design alternatives.

In addition to the boiler design, the available inherent CO control technology includes:

- Good combustion practices

In addition to the inherent available control technology, the add-on CO control technologies include:

- EMxTM
- Catalytic oxidation

Step 2 – Eliminate Technically Infeasible Options

Boiler Design Alternatives

As discussed in the BACT analysis for NO_x in Section 7.1.1 of this document, fluidized bed boiler designs were found to be infeasible for this project.

EMxTM

As discussed in the BACT analysis for NO_x in Section 7.1.1 of this document, EMx has been designed and used only on small to medium sized natural gas-fired stationary turbines for demonstration purposes. EMx has not been demonstrated in practice for biomass boilers and we do not consider this technology achievable for biomass boilers at this time.

Good combustion practices

A modern biomass-fired boiler furnace, operated with computerized controls to ensure good combustion practices would result in a CO emission limit of between 0.23 and 0.35 lb/MMBtu. The boiler design proposed by SPI would emit 0.23 lb/MMBtu of CO when utilizing only good combustion practices to reduce CO emissions. Good combustion practices are a technically feasible technology for controlling CO emissions from biomass-fired boilers.

The add-on technology described below is technically feasible for this project.

Catalytic Oxidation

Catalytic oxidation can be used to control CO when a matrix coated with noble metals facilitates the conversion of a pollutant, such as CO to CO_2. Catalytic oxidizers operate in a temperature range of approximately 650°F to 1,000°F. At lower temperature the CO conversion efficiency falls off rapidly. Although technically feasible, catalytic oxidation has not been reliably demonstrated for biomass boilers. SPI projects that with successful implementation of a catalytic oxidizer the facility may be able to emit 0.1 lb/MMBtu of CO. Other permitted facilities that have not constructed have been permitted at CO emission levels as low as 0.075 lb/MMBtu of CO.

Step 3 – Rank Control Technologies

A summary of recent BACT determinations for biomass-fired stoker boilers with CO emission limits is provided below. The applicant has proposed a CO limit of 0.23 lb/MMBtu (3 hour block average). SPI has proposed the most stringent emission limit of constructed biomass stoker boilers that EPA was able to find in its control technology review.

Table 7.1-3: Summary of Recent CO BACT Determinations for Similar Units

Facility Name	State	Permit #	Permit Date	Control Method	Limit	Averaging time	Status
Beaver Wood Energy	VT	AP-11-015	10-Feb-12	Oxidation Catalyst	0.075 lb/MMBtu	24 hour rolling	Not Constructed
Berlin Biopower	NH	TP-0054	26-Jul-10	Good combustion	0.075 lb/MMBtu	24 hour block	Project Canceled
Warren County Biomass	GA	4911-301-0016	17-Dec-10	Good combustion	0.08 lb/MMBtu	30 day rolling	Not Constructed
South Point	OH	07-00594	4-Apr-06	Oxidation Catalyst	0.1 lb/MMBtu	No Information	Not Constructed
Montville Power LLC	CT	107-0056	6-Apr-10	Oxidation Catalyst	0.1 lb/MMBtu	3 hour block	Not Constructed
International Biofuels	VA	52175	13-Dec-05	Good combustion	0.19 lb/MMBtu	No information	Not Constructed
SPI-Anderson	**CA**	**SAC 12-01**	**Proposed**	**Good combustion**	**0.23 lb/MMBtu**	**3 hour block**	
Fibrominn Biomass	MN	15100038-001	23-Oct-02	Good combustion	0.24 lb/MMBtu	24 hour	
Lindale Renewable Energy	TX	PSDTX1184	8-Jun-10	Good combustion	0.31 lb/MMBtu	30 day rolling	
Lufkin Generating	TX	81706	26-Oct-09	Good combustion	0.31 lb/MMBtu	30 day rolling	
SPI-Aberdeen	WA	PSD-02-02	17-Oct-02	Good combustion	0.35 lb/MMBtu	hourly average	
Beaver Wood Energy Fair Haven	VT	AP-11-015	10-Feb-12	Good combustion	0.35 lb/MMBtu	hourly average	
Darrington Energy	WA	PSD 03-01	11-Feb-05	Good combustion	0.35 lb/MMBtu	24-HR	
Simpson Tacoma Kraft Company	WA	PSD 06-02	22-May-07	Good combustion	0.35 lb/MMBtu	30 day rolling	
Clewiston Sugar Mill And Refinery	FL	PSD-FL-333	18-Nov-03	Good combustion	0.38 lb/MMBtu	12 month rolling	
Koda Energy	MN	13900114	23-Aug-07	Good combustion	0.43 lb/MMBtu	30 day rolling	

However, the new biomass boiler SPI- Anderson has not begun construction at this time. Based on this information, oxidation catalyst is being evaluated as the most stringent control. The remaining feasible control technologies ranked in decreasing order of effectiveness are:

Table 7.1-4: Ranking of CO control technologies

CO control technology	Emission Rate (lb CO /MMBtu)
Catalytic Oxidation	0.10
Good combustion practices	0.23

Step 4 – Economic, Energy and Environmental Impacts

SPI has submitted cost-effectiveness estimates comparing catalytic oxidation and good combustion practices with their projected CO emission rates and the cost of installation and operation of the respective control technologies. SPI assumed that the new boiler's emission rate with the use of an oxidation catalyst for the cost-effectiveness estimates would be lower than any emissions level that EPA has found to be demonstrated in practice. SPI has presumed that the rate of CO emissions with catalytic oxidation and good combustion practices are 0.1 lb/MMBtu and 0.23 lb/MMBtu respectively.

As good combustion practices are the result of proper boiler maintenance and the boiler design, SPI only assessed the incremental cost-effectiveness separating the two technologies. The cost of each additional ton of CO removed by the implementation of catalytic oxidation at the projected cost and emission rate is $8,930. EPA reviewed the cost estimates provided in the PSD permit modification application and determined that it considered the appropriate costs but calculated improper potential to emit emissions estimates. The additional expense of the catalytic oxidizer is due to a higher capital cost in primary equipment along with higher operational, maintenance and lost revenue costs.

Step 5 – Select BACT

SPI has proposed the most stringent CO emissions limit for stoker boilers demonstrated in practice. Although additional tons of possible CO emissions may be controlled by the installation of an oxidation catalyst, SPI has expressed significant doubts that the catalyst will be able to reliably and effectively control CO given its fuel type and operation. In addition, the increased annual costs of an oxidation catalyst present a significant financial burden at this existing sawmill facility.

Based on a review of the available control technologies for CO emissions from biomass boilers selected for this purpose, we have concluded that BACT for the stoker boiler to perform this operation is 0.23 lb/MMBtu (3-hour block average) employing good combustion practices. We are also requiring a lb/hr mass emission rate of 108 lb/hr (3-hour block average) during normal operations.

7.1.3. Particulate Matter- PM, PM_{10}, $PM_{2.5}$

Particulate emissions are the result of unburned solid carbon (soot), unburned vapors or gases that subsequently condense, and unburned portions of fuel (ash). Because the applicant has assumed that all particulate emissions from the boiler are $PM_{2.5}$, the BACT analyses for PM, PM_{10} and $PM_{2.5}$ have been combined. Additionally, the analysis evaluates total particulate emissions – condensable and filterable.

Step 1 – Identify All Control Technologies

The following inherent control options for PM, PM_{10} and $PM_{2.5}$ emissions include:

- Low sulfur fuels for normal operation, and/or pipeline natural gas for startup and shutdown
- Good combustion practices

The available add-on PM, PM_{10}, $PM_{2.5}$ control technologies include:

- Cyclones (including multiclones)
- Venturi scrubber
- Electrostatic precipitator (ESP)
- Baghouse/ Fabric filter.

Low sulfur fuels

The wood fuels to be used predominantly during normal operation along with the pipeline natural gas to be used during startup and shutdown are not generally considered high-sulfur fuels.

Good combustion practices

A modern biomass-fired boiler furnace, operated with computerized controls to ensure good combustion practices, would result in a PM, PM_{10} and $PM_{2.5}$ emission limit between 0.33 lb/MMBtu and 0.56 lb/MMBtu, based on U.S. EPA's AP-42 Compilation of Air Pollutant Emission Factors for wood residue combustion in boilers.

The add-on technologies described below are technically feasible for this project.

Cyclones or Multiclones

Cyclones or multiclones, a series of single cyclone particulate matter separators, operate in a similar manner. An inlet gas stream enters the cyclone or multiclone at an angle causing the gas stream to spin rapidly. The resulting centrifugal forces push the larger particulate into and down along the cyclone walls for collection.

Venturi Scrubbers

Venturi scrubbers reduce particulate by introducing liquid into a converging section of a gas stream. The particulate in the gas stream is removed when it mixes with the liquid and forms tiny droplets that are collected and removed. With gas-side pressure drops exceeding 15 inches of water, particulate collection efficiencies of 85% or greater have been reported for venturi scrubbers operating on wood-fired boilers.

Electrostatic precipitator (ESP)

Electrostatic precipitators use electrostatic forces to separate particulate from the gas stream. When applied to wood-fired boilers, ESPs are often used downstream of mechanical collector pre-cleaners which remove larger-sized particles. Collection efficiencies of 90-99% for particulate have been observed for ESPs operating on wood-fired boilers.

Baghouse/ Fabric filter

Baghouses or fabric filters have had limited applications to wood-fired boilers. The principal drawback to fabric filtration is a fire danger arising from the collection of combustible carbonaceous fly ash. Although some fabric filters have demonstrated lower collection efficiencies, most fabric filter particle collection efficiencies are 90-99%, equivalent to ESPs.

Step 2 – Eliminate Technically Infeasible Options

All of the available control options identified in Step 1 are technically feasible. Cyclones are often used in conjunction with the other control technologies listed above.

Step 3 – Rank Control Technologies

A summary of recent BACT determinations for biomass-fired stoker boilers with PM, PM_{10}, and $PM_{2.5}$ emission limits is provided below. The applicant has proposed a total PM, including filterable and condensable particulate, emission limit of 0.02 lb/MMBtu (3 hour block average)utilizing an ESP preceded by a multiclone. SPI has proposed the most stringent PM, PM_{10}, and $PM_{2.5}$ emission limit of biomass stoker boilers that have constructed.

Table 7.1-5: Recent PM, PM_{10}, $PM_{2.5}$ BACT Determinations for Similar Units

Facility Name	State	Permit #	Permit Date	Control Method	Limit		Status
Berlin Biopower*	NH	TP-0054	07/26/2010	Baghouse	0.01	lb/MMBtu	Project Canceled
Warren County Biomass	GA	4911-301-0016-P-01-0	12/17/2010	Baghouse	0.018	lb/MMBtu	Not Constructed
Beaver Wood Energy Fair Haven	VT	AP-11-015	02/10/2012	ESP	0.019	lb/MMBtu	Not Constructed
SPI-Anderson	**CA**	**SAC 12-01**	**Proposed**	**ESP**	**0.02**	**lb/MMBtu**	
SPI Skagit County Lumber Mill	WA	PSD 05-04	01/25/2006	ESP	0.02	lb/MMBtu	
Darrington Energy Cogeneration	WA	PSD 03-04	02/11/2005	DRY ESP	0.02	lb/MMBtu	
Fibrominn Biomass	MN	15100038-001	10/23/2002	Baghouse	0.02	lb/MMBtu	
Simpson Tacoma Kraft Company	WA	PSD 06-02	05/22/2007	ESP	0.02	lb/MMBtu	
Rome Linerboard Mill	GA	2631-115-0021-V-01-4	10/13/2004	ESP	0.025	lb/MMBtu	
Lufkin Generating Plant	TX	81706	25-Oct-09	ESP	0.025	lb/MMBtu	

*Filterable only

SPI has estimated that the use of a multiclone followed by an ESP or baghouse will be equally effective in the control of particulate matter from the proposed boiler. The feasible control technologies ranked in decreasing order of effectiveness are:

Table 7.1-6: Ranking of PM/ PM_{10}/ $PM_{2.5}$ control technologies

PM/ PM_{10}/ $PM_{2.5}$ control technology	Emission Rate (lb PM/ PM_{10}/ $PM_{2.5}$ per MMBtu)
ESP with multiclone	0.02
Baghouse with multiclone	0.02
Venturi Scrubber	0.30
Low sulfur fuels	0.33
Good Combustion practices	0.33-0.56

Step 4 – Economic, Energy and Environmental Impacts
In EPA's review, three biomass stoker facilities have proposed lower rates of total particulate emissions than SPI- Anderson. The 0.01 lb/MMBTu particulate emissions limit for Laidlaw Berlin Biopower was only for filterable particulate, not total particulate, and the project has been canceled. The succeeding total particulate emission levels in Table 7.1-5 for 0.18 lb/MMBtu and 0.19 lb/MMBtu of total particulate have been proposed but have not been demonstrated in practice. Moreover, the increased levels of control for total particulate in both of cases were proposed with different control technologies.

In our review, EPA found that the lowest achievable total particulate emissions demonstrated in practice from biomass stoker boilers have been achieved with fabric filters or ESPs. With equivalent levels of control, SPI considered the potential economic, energy and environmental impacts from each control system. Baghouses require additional energy to overcome increased pressure drops that occur during the control of particulate. ESP systems use electricity to create an electric field, but typically have lower overall energy requirements than baghouses. As stated earlier, fabric filters may also have an increased fire danger at biomass facilities due to the carbonaceous fly ash.

Step 5 – Select BACT
Based on a review of the available control technologies for PM, PM_{10} and $PM_{2.5}$ emissions from biomass boilers selected for this purpose, we have concluded that BACT

for the stoker boiler to perform this operation is 0.02 lb/MMBtu (3-hour block average) using a multiclone and ESP. We are also requiring a lb/hr mass emission rate of 9.4 lb/hr (3-hour block average) during normal operations.

7.1.3. Startup and Shutdown BACT Limits

The boiler startup process begins by igniting a pile of biomass fuel on the grate and firing two 62.5 MMBtu/hr natural gas burners located near the steam tubes. After approximately 12 hours, the boiler will be at about 50 % of full load and attain a sufficient steady state temperature supporting the activation of the SNCR system. Once the boiler has reached normal operating temperature, as specified by the boiler manufacturer, startup has concluded and the boiler will operate under normal conditions. Shutdown begins when the fuel feed is curtailed and the unit begins cooling. Shutdown ends when the recorded temperature at the superheater outlet reaches 150°F and remains so for at least one hour, or 24 hours has elapsed since the shutdown process began. Add-on particulate controls will be operating during all phases of startup and shutdown. The SNCR will be operating at all appropriate temperature ranges, as specificed by the SNCR manufacturer. During startup and shutdown, the generator shall be disconnected from the electrical grid.

Table 7.1-7 lists the startup and shutdown BACT emission and averaging times. Table 7.1-7 also lists the maximum amount of time for a startup and shutdown event.

Table 7.1-7: BACT for Startup and Shutdown

Pollution and Duration Limits	
NO_x (hourly average)	70.2 lb/hr
CO (hourly average)	108 lb/hr
PM, PM_{10}, $PM_{2.5}$ (24 hour average)	8.93 lb/hr
SO_2 (hourly average)	2.34 lb/hr
Maximum Duration	24 hours

7.2 BACT for Emergency Engine

The project includes a 256hp (190kW) natural gas-fired emergency engine to run the emergency boiler recirculation pump. The limited operation of this unit results in minimal annual emission rates. This equipment is subject to BACT for NO_x, CO, PM, PM_{10}, $PM_{2.5}$. A top-down BACT analysis has been performed and is summarized below.

7.2.1 NO_x, CO, PM, PM_{10}, $PM_{2.5}$ Emissions

Step 1 -- Identify all control technologies

The control options for NO_x emissions from engines include SCR, NO_x reducing catalyst, NO_x adsorber, catalyzed diesel particulate filter, catalytic converter, and oxidation catalyst. A catalytic converter and oxidation catalyst are also control options for CO emissions. A particulate filter/trap can be added for the control of PM, PM_{10}, and $PM_{2.5}$ emissions,

Unlike the main biomass boiler, the emergency engine will be limited in operation and is required to be certified in compliance with NSPS requirements, including emission limits, upon purchase. A review of other BACT determinations was not performed because it is very unlikely that a more detailed review would change the final determination due to the limited use and annual emission rates associated with the proposed limits. The potential to emit for all criteria pollutants subject to BACT review is less than 200 lbs/yr.

Different types of engines have different emission requirements based on the type of engine being purchased. Engine manufacturers may need to employ some of the control technologies identified above in order to comply with the NSPS emission limits, depending on the type of engine and the applicable limits. The applicant is proposing to install an emergency engine for infrequent recirculation pump needs. As a result, SPI must purchase engines that comply with the NSPS and meet the emission requirements for emergency engines. However, we note that the applicant could purchase engines that meet the NSPS standards for non-emergency engines, which have more stringent limits, and operate them as emergency engines. As a result, this review identifies the control technologies to be:

- NSPS-compliant emergency engine
- Engine that meets NSPS for non-emergency engines
- Limiting use (limits on the hours of operation)

Step 2 – Eliminate technically infeasible control options
All of the control technologies identified are assumed to be technically feasible.

Step 3 – Rank remaining control technologies
The available control technologies are ranked according to control effectiveness in Table 7.2-1.

Table 7.2-1: NSPS Limits for Engines

Engine Type (190kW)	NO_x +NMHC (g/kW-hr)	CO (g/kW-hr)	PM (g/kW-hr)
Non-emergency engine	0.59	3.5	0.02
Emergency engine	4.0	3.5	0.20

Step 4 – Economic, Energy and Environmental Impacts
Due to economic impacts and limited environmental benefit, the use of add-on controls for the emergency engine and purchasing an engine that meet NSPS standards for a non-emergency engine and operating it as an emergency engine would be impractical in this case. This is illustrated in Table 7.2-2 by the potential emissions from the emergency engine (based on 100 hours of operation per year and complying with the NSPS for emergency engines). Requiring the additional reductions in emissions that would be

gained by use of engines that meet NSPS standards for non-emergency engines would have very little environmental benefit and not justify the cost.

Table 7.2-2: Summary of PTE for 190 kW Emergency Engine

Pollutant	Emergency Engine (tpy)
NO_x	0.039
CO	0.306
PM, PM_{10}, $PM_{2.5}$	0.0011

Step 5 – Select BACT
Based on a review of the available control technologies, we have concluded that BACT is limiting the hours of operation and the emission limits listed in Table 7.2-3 based on a 3-hour average. It is assumed that newly purchased engines would be the most energy efficient available and that operating in compliance with NSPS requirements will ensure that each engine is properly maintained and as efficient as possible.

Table 7.2-3: Summary of BACT for 190 kW Emergency Engine

Engine Type	NO_x+NMHC (g/kW-hr)	CO (g/kW-hr)	PM (g/kW-hr)
Emergency engine	4.0	3.5	0.20

7.3. BACT for Cooling Towers

The proposed project also requires a cooling tower system to dissipate the heat load into the atmosphere. The cooling tower system is subject to BACT for PM, PM_{10}, and $PM_{2.5}$. A top-down BACT analysis has been performed and is summarized below. The applicant conservatively assumed PM, PM_{10} and $PM_{2.5}$ emissions from the cooling tower were equivalent.

Step 1 - Identify All Control Technologies
The following inherent control options for PM, PM_{10}, and $PM_{2.5}$ emissions include:
- Wet cooling
- Dry cooling
- Wet-Dry Hybrid cooling

<u>Wet cooling</u>
Cooling towers are heat exchangers that are used to dissipate large heat loads to the atmosphere. They are used as an important component in many industrial and commercial processes needing to dissipate heat. Wet cooling towers rely on the latent heat of water evaporation to exchange heat between the process and the air passing through the cooling tower.

A two-cell evaporative cooling tower for this project would require a water load 4.24 gallons per minute per square foot. The expected air velocity is 503 feet per minute. Fugitive particulate emissions would be generated from the cooling tower due to the total dissolved solids (TDS) in the water.

Dry cooling

Dry cooling uses an air cooled condenser (ACC) that cools the steam turbine generators' exhaust steam using a large array of fans that force air over finned tube heat exchangers. The exhaust from the steam turbine flows through a large diameter duct to the ACC where it is condensed inside the tubes through indirect contact with the ambient air. The heat is then released directly to the atmosphere.

Wet-Dry Hybrid cooling

Wet-Dry Hybrid cooling uses wet and dry cooling technologies in parallel, and uses all of the equipment involved in both wet and dry cooling. Hybrid cooling technology divides the cooling function between the wet and dry systems depending on the capabilities of each system under different environmental and operational conditions.

The available add-on PM, PM_{10}, and $PM_{2.5}$ control technologies include:

- Drift eliminators

Drift Eliminators

Drift eliminators are usually incorporated into the tower design to remove as many droplets as practical from the air stream before exiting the tower. The drift eliminators used in cooling towers rely on inertial separation caused by direction changes while passing through the eliminators. Types of drift eliminators include many different configurations and various materials. The materials may include other features, such as corrugations and water removal channels, to enhance the drift removal further.

Step 2 – Eliminate Technically Infeasible Options

All of the available control options identified in Step 1 are technically feasible.

Step 3 – Rank Control Technologies

The remaining feasible control technologies ranked in decreasing order of effectiveness are:

Table 7.3-1: Ranking of PM/ PM_{10}/ $PM_{2.5}$ control technologies

PM/ PM_{10}/ $PM_{2.5}$ control technology	**Emission Rate (tpy of PM, PM_{10}, $PM_{2.5}$)**
Dry cooling	0
Wet-Dry Hybrid cooling	0.55[7]
Wet cooling with 0.0005% Drift Eliminators	1.10

The applicant has proposed to use wet cooling with DRU-1.5 high-efficiency mist eliminators with a drift loss of less than 0.0005%. This is the equal to the lowest proposed amount of drift that EPA has found in its review of similar facilities.

[7] The applicant did not estimate potential emissions from a wet-dry hybrid system. We have approximated emissions from such a system to be one-half of those from a wet cooling system.

EPA did not find any sawmill facilities or biomass boilers that use dry cooling or wet-dry hybrid cooling as an alternative to wet cooling. As shown in Table 7.3-1 the potential impact from the various control options will have a limited effect on the total PM emissions from the project. The difference in potential to emit resulting from the cooling tower options is 1.10 tpy of total PM.

Step 4 – Economic, Energy and Environmental Impacts
The use of a dry or hybrid wet-dry system would reduce the overall efficiency of the facility, due to the additional energy requirements for the wet and hybrid systems. Moreover, dry and wet-dry cooling systems are typically more costly than a more conventional wet cooling tower system. On the other hand, the use of wet cooling has a potential environmental impact associated with additional consumption of water resources.

Step 5 – Select BACT
Based on a review of the available control technologies for PM, PM_{10}, $PM_{2.5}$emissions from cooling towers selected for this operation, and the limited amount of total particulate resulting from the cooling tower operation, we have concluded that the proposed boiler can utilize wet cooling.

Utilizing the wet cooling tower option, SPI has elected to use the most stringent control option available, by limiting drift to 0.0005%. Therefore, BACT for the cooling tower in the proposed modification will be the use of a wet cooling tower with a drift loss of less than 0.0005%.

8. Air Quality Impacts

CAA Section 165 and EPA's PSD regulations at 40 CFR § 52.21 require an examination of the impacts of the proposed SPI- Anderson project on ambient air quality. The applicant must demonstrate, using air quality models, that the facility's emissions of PSD-regulated air pollutants would not cause or contribute to a violation of (1) the applicable NAAQS, or (2) the applicable PSD increments (explained below in Sections 8.4 and 8.5). These sections of the AAQIR include a discussion of the relevant background data and air quality modeling, and EPA's conclusion that the project will not cause or contribute to an exceedance of the applicable NAAQS or applicable PSD increments and is otherwise consistent with PSD requirements governing air quality.

8.1 *Introduction*

8.1.1 Overview of PSD Air Impact Requirements

Under the PSD regulations, permit applications for major sources must include an air quality analysis demonstrating that the facility's emissions of the PSD-regulated air pollutants will not cause or contribute to a violation of the applicable NAAQS or applicable PSD increments. (A PSD increment for a pollutant applies only to areas that meet the corresponding NAAQS.) The applicant provides separate modeling analyses for each criteria pollutant emitted above the applicable significant emission rate. If a preliminary analysis shows that the ambient concentration impact of the project by itself is greater than the Significant Impact Level (SIL), then a full or cumulative impact analysis is required for that pollutant. The cumulative impact analysis includes nearby pollution sources in the modeling, and adds a monitored background concentration to account for sources not explicitly included in the model. The cumulative impact analysis must demonstrate that the modification will not cause or contribute to a NAAQS or increment violation. If a preliminary analysis shows that the ambient concentration impact of the project by itself is less than the SIL, then further analysis is generally not required. Required model inputs characterize the various emitting units, meteorology, and the land surface, and define a set of receptors (spatial locations at which to estimate concentrations, typically out to 50 km from the facility). Modeling should be performed in accordance with 40 CFR § 51, Appendix W- *Guideline on Air Quality Models* (GAQM). AERMOD with its default settings is the standard model choice, with CALPUFF available for complex wind situations.

A PSD permit application typically includes a Good Engineering Practice (GEP) stack height analysis, to ensure that downwash is properly considered in the modeling, and stack heights used as inputs to the modeling are no greater than GEP height, so as to disallow artificial dispersion from the use of overly tall stacks. The application may also include initial "load screening," in which a variety of source operating loads and ambient temperatures are modeled, to determine the worst-case scenario for use in the rest of the modeling.

The PSD regulations also require an analysis of the impact on nearby Class I areas, generally those within 100 km, though the relevant Federal Land Manager (FLM) may specify additional or fewer areas. This analysis includes the NAAQS, PSD increments, and Air Quality Related Values (AQRVs). AQRVs are defined by the FLM, and typically limit visibility degradation and the deposition of sulfur and nitrogen. Generally, CALPUFF is the standard model choice for Class I analyses because it can handle visibility chemistry as well as the typically large distances (over 50 km) to Class I areas.

Finally, the PSD regulations require an additional impact analysis, showing the project's effect on visibility, soils, vegetation, and growth. This visibility analysis is independent of the Class I visibility AQRV analysis. The additional impact analysis for the SPI-Anderson project is discussed in Section 9.

8.1.2 Identification of SPI- Anderson Modeling Documentation

The applicant, SPI, submitted numerous documents and materials which comprise the entire modeling analysis. *PSD and ATC permit Application* (May 2007) contains the results of the original modeling and most of the Class I analyses. The updated *PSD and ATC Application* and associated compact disc (March 2010) contain updated modeling results. *Response to Incompleteness Determination #1* (July 2010), containing a full impact analysis for compliance with the 1-hour NO_2 NAAQS and a partial Additional Impacts Analysis. *Response to Incompleteness Determination #2* (September 2010) revisits the 1-hour NO_2 NAAQS compliance analysis and provides monitoring and meteorology background information. *Startup/Shutdown Information* (December 2010) contains proposed limits on the number of annual startups and shutdowns. *Response to Additional Information Request* (June 2011) provides further information on proposed startup and shutdown emission limits. *Updated Air Dispersion Modeling Analysis* (May 2012) contains modeling files and an updated modeling analysis that reflects project changes since the March 2010 submittal. *Surface Characteristics* (June 2012) describes the surface characteristics between the meteorology site and the project site as well as modeling receptor network. *Background Concentration Information* (June 2012) supplies information regarding the monitoring background concentrations. *CALPUFF Modeling Files* (June 2012) contains archived CALPUFF modeling files developed for the original May 2007 PSD application and used in subsequent submittals.

8.2. Background Ambient Air Quality

The PSD regulations require the air quality analysis to contain air quality monitoring data as needed to assess ambient air quality in the area for the PSD-regulated pollutants for which there are NAAQS that may be affected by the source. In addition, for demonstrating compliance with the NAAQS, a background concentration is added to represent those sources not explicitly included in the modeling, so that the total accounts for all contributions to current air quality.

The applicant used ambient air concentrations of NO_2, which were recorded at Manzanita Avenue in Chico 55.5 miles (90 km) south of the facility's current location. This was the closest and most representative NO_2 monitor to the site. For $PM_{2.5}$ background concentrations, the applicant used data from a monitor at the Redding Department of Health which is approximately 6.5 miles (10.5 km) northeast from the facility. The applicant took PM_{10} background concentrations from Anderson, which is around 6.5 miles southeast from the facility site.

Table 8.2-1 describes the maximum background concentrations (from 2011) of the PSD-regulated pollutants for which there are NAAQS that may be affected by the project's emissions, and the corresponding NAAQS.

Table 8.2-1: Maximum Background Concentrations and NAAQS

Pollutant, Averaging Time	Background Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
NO_2, 1-hour	62.7 (33 ppb)	188 (100 ppb)
NO_2, annual	33.1 (17 ppb)	100 (53 ppb)
PM_{10}, 24-hour	42	150
$PM_{2.5}$, 24-hour	15.3	35
$PM_{2.5}$, annual	5.3	15
CO, 1-hour	2,976 (2.6 ppm)	40,000 (35 ppm)
CO, 8-hour	2,404 (2.1 ppm)	10,000 (9 ppm)
Ozone, 8-hour	71 ppb	75 ppb

Note: The $PM_{2.5}$ 24-hr value is 98^{th} percentile averaged over three years rather than maximum
The NO_2 1-hr value is 98^{th} percentile averaged over three years rather than maximum
The Ozone 8-hour value is the fourth highest 8-hour concentration averaged over three years

8.3 Modeling Methodology for Class II areas

The applicant modeled the impact of SPI- Anderson on the NAAQS and PSD Class II increments using AERMOD in accordance with GAQM. The modeling analyses included the maximum air quality impacts during normal operations and startups and shutdowns, as well as a variety of conditions to determine worst case, short-term air impacts.

8.3.1 Model selection

As discussed in the PSD Application (Updated PSD Application, March 2010, p.11pdf15), the model that the applicant selected for analyzing air quality impacts in Class II areas is AERMOD, along with AERMAP for terrain processing and AERMET for meteorological data processing. This is in accordance with the default recommendations in Section 4.2.2 on Refined Analytical Techniques in GAQM.

8.3.2 Meteorology model inputs

AERMOD requires representative meteorological data in order to accurately simulate air quality impacts. The applicant used surface meteorological data collected for a five consecutive-year period (2004-2008) at the Redding Municipal Airport meteorological station. This station is located approximately 2.8 (4.5 km) miles from the project site. The applicant processed these data using EPA's AERMET data processor. EPA concurs that the chosen 2004-2008 Redding data is the most representative for the SPI- Anderson analysis.

For upper air data, the applicant obtained data from the 2004-2008 Medford, Oregon upper air site located approximately 134 miles (215 km) northwest of the project site as being the most representative site available that had data complete enough to use. No other upper air meteorological monitoring stations are located closer to the project site. (Updated PSD Application,p.13pdf.17). EPA agrees that it is appropriate to use Medford, Oregon upper air data for the SPI- Anderson analysis.

8.3.3 Land characteristics model inputs

Land characteristics are used in the AERMOD modeling system in three ways: 1) via elevation within AERMOD to assess plume interaction with the ground; 2) via a choice of rural versus urban algorithm within AERMOD; and 3) via specific values of AERMET parameters that affect turbulence and dispersion, namely surface roughness length, Bowen ratio, and albedo. The surface roughness length is related to the height of obstacles to the wind flow and is an important factor in determining the magnitude of mechanical turbulence. The Bowen ratio is an indicator of surface moisture. The albedo is the fraction of total incident solar radiation reflected by the surface back to space without absorption.

Terrain elevations for receptors and emission sources were prepared using 1/3rd arc-second National Elevation Dataset data developed by the United States Geological Survey (USGS), and available on the internet from the USGS Seamless Data Server (http://seamless.usgs.gov/index.php). These data have a horizontal spatial resolution of approximately 10 meters. Terrain heights surrounding the facility indicate that some of the receptors used in the simulations were located in intermediate or complex terrain (above stack or plume height). For determining concentrations in elevated terrain, SPI chose the AERMAP terrain preprocessor receptor-output file option.

SPI determined surface parameters including the surface roughness length, albedo, and Bowen ratio for the area surrounding the Redding Municipal Airport meteorological tower using the AERMET preprocessor, AERSURFACE (Version 08009), and the USGS 1992 National Land Cover (NLCD92) land-use data set. The NLCD92 data set used in the analysis has 30 meter data point spacing and 21 land-use categories. Seasonal surface parameters were determined using AERSURFACE according to EPA's guidance.

EPA requested additional detail characterizing the surface parameters surrounding the SPI-Anderson site for comparison with the airport site. Based on this comparison, the applicant and EPA conclude that the use of Redding meteorological data is adequately representative of the project site.

8.3.4 Model receptors

Receptors in the model are geographic locations at which the model estimates concentrations. The applicant places the receptors such that they have good area coverage and are closely spaced enough so that the maximum model concentrations can be found. At larger distances, spacing between receptors may be greater than it is close to the source, since concentrations vary less with increasing distance. The spatial extent of the receptors is limited by the applicable range of the model (roughly 50 km for AERMOD), and possibly by knowledge of the distance at which impacts fall to negligible levels. Receptors need be placed only in ambient air, that is, locations to which the public has access, and that are not inside the project fence line.

The applicant used Cartesian coordinate receptor grids to provide adequate spatial coverage surrounding the project area and to identify the extent of significant impacts and the maximum impact location. For all analyses except 1-hour average NO_2, receptors were spaced 500 m apart covering the 10 km square simulation domain, with 200 m, 50 m, and 25 m spacing receptors grids covering 5 km, 2.5 km, and 1.25 km nested square areas centered on the facility, respectively. Receptors were also located at 25 m intervals along the facility property boundary. For the 1-hour average NO_2 analysis, the modeling domain was extended to 20 km, and the additional area was covered by receptors placed 500 m apart. (Surface Characteristics, p.1pdf1)

8.3.5 Stack parameter model inputs

The modeling conducted by the applicant used the corresponding stack parameters in Table 8.3-1 for normal operations and during startup and shutdown to provide conservative estimates of SPI- Anderson impacts.

Table 8.3-1: Load Screening and Stack Parameters for Cogeneration Unit

Operating Mode	Stack Height (ft)	Stack Diameter (ft)	Stack Velocity (ft/sec)	Stack Temperature (°F)
SU/SD	85	8.5	36.7	294
Normal	85	8.5	61.1	350

Operating Mode	NO_x (lb/hr)	PM_{10}/ $PM_{2.5}$ (lb/hr)	CO (lb/hr)
SU/SD	70.2	8.93	432
Normal	70.2	8.93	108

Source for both parts of table 8-3: Updated Air Dispersion Modeling Analysis (May 2012), p.3, Tables 1,2 and 5pdf.3, 7 and 10.

8.3.6 Good Engineering Practice (GEP) Analysis

The applicant performed a Good Engineering practice (GEP) stack height analysis to ensure that downwash is properly considered and that stack heights used as inputs to the modeling are no greater than GEP height. This disallows artificial dispersion from the use of overly tall stacks. As is typical, the GEP analysis was performed with EPA's *Building Profile Input Program* software, which uses building dimensions and stack heights as inputs. Based on the analysis, the applicant shows that the GEP stack height for the boiler stack would have to exceed the maximum creditable GEP height of 65 m in order to ensure protection against downwash. The applicant showed that the GEP stack height for the other equipment was similarly greater than the planned heights. So, for all emitting units, the applicant used the planned actual stack heights for inputs in AERMOD modeling, and included wind direction-specific Equivalent Building Dimensions to properly account for downwash. (PSD Application p.14pdf.18)

8.4 *National Ambient Air Quality Standards (NAAQS) and PSD Class II Increment Consumption Analysis*

8.4.1 Pollutants with significant emissions

40 CFR § 52.21 requires an air quality impact analysis for each PSD-regulated pollutant (for which there is a NAAQS) that a major source has the PTE in a significant amount, *i.e.*, an amount greater than the Significant Emission Rate (SER) for the pollutant. Applicable SPI- Anderson emissions and the SERs are shown in Table 8.4-1. As shown in Table 8.4-1, EPA does not expect SPI- Anderson to emit Pb, VOC and SO_2 in significant amounts. However, based on the estimates submitted by the applicant, EPA expects SPI- Anderson to emit CO, NO_x, PM_{10}, and $PM_{2.5}$ in significant amounts. Therefore, this project triggers the air impact analyses requirements for CO, NO_2, PM_{10} and $PM_{2.5}$.

Table 8.4-1: PSD Applicability to SPI- Anderson: SER

Pollutant	Emissions (tpy)	SER (tpy)	Does PSD Apply?
CO	472	100	Yes
NO_x	267	40	Yes
PM_{10}	42.1	15	Yes
$PM_{2.5}$	42.1	10	Yes
SO_2	10.3	40	No
Pb	0.03	0.6	No
VOC	34.8	40	No

8.4.2 Preliminary analysis: Project-only impacts (Normal Operations and Startup)

EPA has established Significant Impact Levels (SILs) to characterize air quality impacts. A SIL is the ambient concentration resulting from the facility's emissions, for a given pollutant and averaging period, below which the source is considered to have an insignificant impact. For maximum modeled concentrations below the SIL, further air quality analysis for the pollutant is generally not necessary. In some cases it may be appropriate to consider additional information in order to conclude that a source will not be responsible for creating a new NAAQS exceedance, however. For maximum concentrations that exceed the SIL, EPA requires a cumulative modeling analysis, which incorporates the combined impact of nearby sources of air pollution to determine compliance with the NAAQS and PSD increments.

Table 8.4-2 shows the results of the preliminary or project-only analysis based on maximum operations for SPI- Anderson. Startup emissions are used for determining the maximum 1-hour NO_2, 1-hour and 8-hour CO, and 24-hour PM_{10}, $PM_{2.5}$ impacts with maximum project impacts from normal operations included in parentheses. Startup CO emissions are expected to exceed those experienced during normal operating conditions. Startup and normal 1-hour NO_2 and 24-hour PM_{10}, $PM_{2.5}$ emissions are the same; only the flow rates are lower for the startup case. 1-hour NO_2 impacts are based on the assumption that 80% of the NO is converted to NO_2, while the annual average NO_2 concentrations are based on the assumption that 75% of the NO is converted to NO_2. Based on Table 8.4-2, SPI- Anderson's impacts are significant only for annual and 1-hour NO_2, and 24-hour $PM_{2.5}$, and we have determined that in this case cumulative impacts analyses are required only for these pollutants and averaging periods.

Table 8.4-2: SPI- Anderson Significant Impacts

NAAQS pollutant, Averaging Time	Project-only Modeled Impact (µg/m^3)	Significant Impact Level (µg/m^3)	Significant Impact?
NO_2, 1-hour	38.6 (26.3)	7.5 (4 ppb)	Yes
NO_2, annual	1.35	1	Yes
PM_{10}, 24-hour	3.36 (2.23)	5	No
$PM_{2.5}$, 24-hour	3.11 (1.84)	1.2	Yes
$PM_{2.5}$, annual	0.27	0.3	No
CO, 1-hour	307 (122)	2000	No
CO, 8-hour	212 (36)	500	No

Sources: Updated Modeling Analysis (May 2012), Tables 3 and 6pdf8,11

8.4.3 Cumulative impact analysis

A cumulative impact analysis considers impacts from nearby sources in addition to impacts from the project itself. For demonstrating compliance with the NAAQS the applicant also adds a background concentration to represent those sources not explicitly included in the modeling, so that the total accounts for all contributions to current air quality. In this case, the applicant submitted cumulative impact analyses demonstrating compliance with the 24-hour $PM_{2.5}$ NAAQS and the annual and 1-hour NO_2 NAAQS.

PSD increments are limits on cumulative air quality degradation. They are set to prevent air with pollutant concentrations lower than the NAAQS from being degraded to the level of the NAAQS. PSD increments apply in addition to the NAAQS. Increments have been established for some pollutants, such as for this project, specifically for NO_2, PM_{10} and $PM_{2.5}$. For demonstrating compliance with the PSD increment, only increment-consuming sources need to be included because the increment concerns only changes occurring since the applicable baseline date.

There is an annual NO_2 PSD increment, but there is no 1-hour NO_2 PSD increment; therefore, only 24-hour $PM_{2.5}$ and annual NO_2 require cumulative PSD increment analyses.

For evaluating NO_2 annual increment in this analysis, the applicant used all of the same sources that were in the NAAQS inventory, which is conservative.

With respect to the PSD increment analysis for $PM_{2.5}$, the applicable trigger date when the $PM_{2.5}$ increments become effective under the Federal PSD program is October 20, 2011. The SPI- Anderson PSD permit application was determined to be administratively complete by EPA on October 4, 2010. However, EPA is requiring each source that receives its PSD permit after the trigger date, regardless of when the application was submitted, to provide a demonstration that the proposed emissions increase, along with other increment consuming emissions will not cause or contribute to a violation of the $PM_{2.5}$ increments. Also the major source baseline, which precedes the trigger date is the date after which actual emissions increases associated with construction at any major stationary source consume PSD increment. That date is October 20, 2010. With this PSD permit, SPI-Anderson would begin construction after this date. In general, for $PM_{2.5}$, the minor source baseline date is the earliest date after the trigger date of a complete PSD permit application for a source with a proposed increase in emissions of $PM_{2.5}$ that is significant. No source has triggered the minor source baseline date in the area at issue. Other than SPI- Anderson's projected construction emissions, there have been no actual emissions changes of $PM_{2.5}$ from any new or modified major stationary source on which construction commenced after October 20, 2010. Therefore, the only source to consume $PM_{2.5}$ increment in the area is SPI- Anderson. The applicant considered only the allowable emissions increase from the SPI- Anderson project in the 24-hour $PM_{2.5}$ increment analysis.

8.4.3.1 Nearby source emission inventory

For both the PSD increment and NAAQS analyses, there may be a large number of sources that could potentially be included. Only sources with a significant concentration gradient in the vicinity of the source need to be included; the number of such sources is expected to be small, except in unusual situations. (GAQM 8.2.3)

Shasta and Tehama Counties provided a list of all stationary sources within their counties and within 55.4 km of the project site (approximate distance to the farthest significant impact plus 50 km) for NO_2 and 51.0 km for $PM_{2.5}$. A comprehensive procedure was used to determine which sources were included in the emissions inventory to be modeled. This included screening out a source by whether it had a significant impact where the project was predicted to have a significant impact.

We note that short-term maximum emission rates are used rather than annual emission rates to determine the distance over which a facility might have a significant impact for short-term standards (*e.g.*, hourly NO_2). Use of short-term rates results in the greatest impacts at the farthest distance. Thus, the peak rates that occur during startup determine the SPI- Anderson significant impact area (SIA) for hourly NO_2.

SPI identified nine facilities nearby for inclusion in the emission inventory for the 1-hour NO_2 cumulative analysis, based on data from Shasta and Tehama Counties. The following non-SPI- Anderson facilities and their NO_x and $PM_{2.5}$ emissions are included in the cumulative compliance demonstration: Kiara Co Gen project, Wheelabrator Shasta Co-Gen (NO_x only), Wheelabrator Lassen Gas Turbine (NO_x only), City of Redding power plant (NO_x only), Ag Products Asphalt (NO_x only), JF Shea Smith Road Asphalt, Lehigh Cement (NO_x only), North State Asphalt (NO_x only), and Tehama Processing (NO_x only). These facilities are large enough and close enough to the project site to have the potential to directly impact the project's SIA. (Updated Air Dispersion Modeling Analysis, Tables 13-14pdf.20-21).

Current EPA NO_2 guidance recommends that emphasis on determining which nearby sources to include in the nearby source inventory should focus on the area within about 10 km of the project location in most cases. This indicates that the SPI- Anderson inventory is adequate for performing these cumulative analyses (p.16 of "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour

NO_2 National Ambient Air Quality Standard", Memorandum from Tyler Fox, EPA Air Quality Modeling Group to EPA Regional Air Division Directors, March 1, 2011).

Considering a focus on sources within 10 km, EPA concludes that the combination of representative background monitored concentrations and the additional consideration of sources out to 50 km provide sufficient justification for the inventories used in the cumulative analysis.

8.4.3.2 Discussion of Certain $PM_{2.5}$-Specific Considerations

EPA has issued guidance on how to combine modeled results with monitored background concentrations which the applicant adequately followed. ("Modeling procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS", memorandum from Stephen D. Page, Director, EPA OAQPS, March 23, 2010.)

SPI provided a cumulative $PM_{2.5}$ 24-hour analysis. The applicant's analysis conservatively assumed that all PM_{10} emissions were comprised of $PM_{2.5}$ emissions, and therefore used PM_{10} emissions data as input to the modeling. Thus, actual $PM_{2.5}$ impacts are expected to be lower than those indicated in the model results.

$PM_{2.5}$ is either directly emitted from a source (primary emissions) or formed through chemical reactions with pollutants already in the atmosphere (secondary formation). EPA has not developed and recommended a near-field model that includes the necessary chemistry algorithms to estimate secondary impacts in an ambient air analysis.

The SPI- Anderson application does not specifically address secondarily formed $PM_{2.5}$ (as distinguished from directly emitted primary $PM_{2.5}$). Secondary $PM_{2.5}$ is formed through the emission of non-particulates (*i.e.*, gases) – such as SO_2 and NO_x – that turn into fine particulates in the atmosphere through chemical reactions or condensation. Using the results for $PM_{2.5}$ impacts given in Tables 8.4-2 and 8.4-3 and the projected emission rates of SO_2, NO_x and $PM_{2.5}$, EPA notes that the SPI- Anderson emissions of 10.3 tpy SO_2 are less than the SO_2 SER of 40 tpy, and would not be expected to result in significant secondary $PM_{2.5}$. The SPI- Anderson NO_x emissions of 267 tpy are above the NO_x SER of 40 tpy. However, secondary $PM_{2.5}$ formation occurs only as a result of chemical transformations that would affect only a portion of those emissions. Moreover, the formation occurs gradually over time as the plume travels and becomes increasingly diffuse and would be expected to be considerably smaller than the impacts from the 42.1 tpy of directly emitted primary $PM_{2.5}$. The maximum impact of source primary $PM_{2.5}$ was 3.11 $\mu g/m^3$ for 24-hour $PM_{2.5}$ and 0.27 $\mu g/m^3$ for annual $PM_{2.5}$. The 24-hour $PM_{2.5}$ cumulative impacts analysis which gives a maximum impact of 28.8 ug/m^3, with a background concentration of 15.3 ug/m^3, indicates that at least 6.2 $\mu g/m^3$ remains available for the 24-hour averaging time before the NAAQS is challenged (35 $\mu g/m^3$ – 28.8 $\mu g/m^3$). For the annual averaging time no cumulative impact analysis was required because the project's annual impacts were less than the SIL. However, the background concentration was 5.3 $\mu g/m^3$. Adding this result to the project's predicted impact of 0.27 $\mu g/m^3$ yields a concentration of 5.57 $\mu g/m^3$. This result is less than a third of the NAAQS and leaves about 9 $\mu g/m^3$ remaining before the NAAQS is challenged. The monitored background $PM_{2.5}$ concentrations would also conservatively include secondarily formed $PM_{2.5}$ from the surrounding/nearby sources. Because the secondary $PM_{2.5}$ formation from SPI- Anderson's NO_x emissions would be expected to be considerably smaller than the primary $PM_{2.5}$ impacts, they would also be smaller than the additional 6.2 $\mu g/m^3$ or 9 $\mu g/m^3$ needed to cause or contribute to a $PM_{2.5}$ NAAQS violation. In addition, most of these chemical transformations in the atmosphere occur slowly (over hours or even days, depending on atmospheric conditions and other variables), causing secondary $PM_{2.5}$ impacts to occur generally at some distance from the source of its gaseous emissions precursors, and are unlikely to overlap with nearby maximum primary $PM_{2.5}$ impacts.

8.4.3.3 Discussion of Certain 1-hour NO_2-Specific Considerations

While the new 1-hour NO_2 NAAQS is defined relative to ambient concentrations of NO_2, the majority of NO_x emissions from stationary sources are in the form of nitric oxide (NO) rather than NO_2. GAQM notes that the impact of an individual source on ambient NO_2 depends in part "on the chemical environment into which the source's plume is to be emitted" (see Section 5.1.j). Because of the role NO_x chemistry plays in determining ambient impact levels of NO_2 based on modeled NO_x emissions, Section 5.2.4 of GAQM recommends a three-tiered screening approach for NO_2 modeling. Later guidance documents issued by EPA expand on this approach. Tier 1 assumes full conversion of NO to NO_2. Tiers 2 and 3 are refinements of the amount of conversion of NO to NO_2. The applicant used the Tier 2 approach, in which the 1-hour NO_2 impacts are based on the assumption that 80% of the NO is converted to NO_2, while the annual average NO_2 concentrations are based on the assumption that 75% of the NO is converted to NO_2.

A. NO_2 monitor representativeness/conservativeness
The applicant chose the Manzanita Avenue monitor in Chico for background NO_2 concentrations. This monitor is approximately 90 km from the SPI- Anderson site and is the closest NO_2 monitor to the project site. No other NO_2 monitor is located within 90 km of the site. Despite its distance from the project site, the monitor from Chico is conservative based on its proximity to a more industrial area at the north end of the Sacramento Valley.

B. Combining modeled and monitored values
SPI used one of the approaches in an EPA March 2011 memo which recommends using the 98^{th} percentile of the annual distribution of daily maximum 1-hour values averaged across the most recent three years of monitored data as a uniform background contribution to the modeled results. This procedure is based on a conservative assumption.

EPA believes that the applicant's overall approach to the 1-hour NO_2 analysis for the SPI- Anderson project, including the emission inventory, background concentrations of NO_2 and the method for combining model results with monitored values, is adequately conservative.

8.4.3.4 Startup and Shutdown Analyses

As stated in Section 8.3.5, the applicant estimated boiler NO_x emissions during startup and shutdown to be the same as those during normal operations, but with lower flow rates, thus the applicant also modeled for startup and shutdown. The stack parameters input into the model such as exit temperature and exhaust velocity were consistent with a flow rate equal to approximately 60% of that associated with a full load, and a reduced exhaust temperature of 250 °F or 394 degrees K (Updated Air Dispersion Modeling Analysis, May 2012). The startup period may last up to 24 hours from a “cold” (ambient temperature) furnace with the initial fire employing natural gas-fired burners combusting pipeline natural gas. SPI- Anderson anticipates only two planned cold startup and shutdown events during the year for maintenance.

8.4.3.5 Results of the Cumulative Impacts Analysis

The results of the PSD cumulative impacts analysis for SPI- Anderson’s normal operations for $PM_{2.5}$ and startup emissions for 1-hour NO_2 are shown in Table 8.4-3. The analysis demonstrates that emissions from SPI- Anderson will not cause or contribute to exceedances of the NAAQS for annual and 1-hour NO_2 or 24-hour $PM_{2.5}$ or for the increments for annual NO_2 or 24-hour $PM_{2.5}$. The background concentrations were taken from Table 8.2-1.

EPA also considered additional information to ensure that the modification would not be responsible for causing a new NAAQS exceedance outside this modeling area. EPA considered sources in Shasta and Tehama Counties (no sources of interest were located outside of these counties) that were not included, but which had been evaluated for inclusion/exclusion in the cumulative impacts modeling. EPA concluded that these sources are either small enough or distant enough that the project’s expected emissions along with emissions from these sources would not create any new NAAQS exceedance in the modeling area outside of the SIA.

Table 8.4-3: SPI- Anderson Compliance with Class II PSD Increments and NAAQS

Pollutant. Averaging Time	All Sources Modeled Impact	Background Concentration	Cumulative Impact w/ Background	NAAQS ($\mu g/m^3$)	PSD Increment Consumption	PSD Increment
NO_2, 1-hour	94	62.7	157	188 (100 ppb)	NA	NA
NO_2, annual	1.75	33.1	34.8	100 (53)	1.75	25
$PM_{2.5}$, 24-hour	13.5	15.3	28.8	35	3.36	9

Notes: - There are no PSD increments defined for 1-hour NO_2.
Sources:
NO_2, $PM_{2.5}$ (NAAQS): Updated Air Dispersion Modeling Analysis (May 2012) Tables 15 and 16pdf22-23: $PM_{2.5}$ increment consumption less than all sources modeled impact due to non-increment consuming fugitive source at SPI- Anderson being included in NAAQS analysis.

8.4.3.6 Impact on Ozone Levels

There is a projected 267 tpy increase in NO_x emissions. Shasta County is an attainment area for O_3. There are four O_3 monitors located in the Redding area. The highest design value from these monitors is 71 ppb. The monitor with the highest value is located on the north side of Redding about 25 km from SPI-Anderson. The NAAQS is exceeded if the design value is 75 ppb. As explained further below, there is no evidence in any recent O_3 regional modeling that an increase in 267 tpy of NO_x would result in a 4 ppb O_3 increase and threaten the NAAQS.

The emissions of VOC and NO_x that react to form O_3 come from a variety of local and regional anthropogenic and natural source categories. Anthropogenic VOC emissions are associated with evaporation and combustion processes, especially industrial processes and transportation. Natural VOC emissions from vegetation are much larger than those from anthropogenic sources. Anthropogenic NO_x emissions are associated with combustion processes, especially mobile sources and electric power generation plants. Major natural sources of NO_x include lightning, soils, and wildfires. Given the large number of local and regional VOC and NO_x sources affecting O_3 concentrations in a given area, the impact of any single emission source is generally very small.

Furthermore, given the complex nature of O_3 chemistry, the response of the O_3 system can be rather stiff in certain areas, meaning that it generally takes a substantial change in precursor emissions to produce a discernible change in O_3 concentrations on a single day. For example, modeling performed for the San Joaquin Valley 2007 Ozone Plan for the Hanford site indicates changes in NO_x emissions over the entire air basin on the order of 20% may increase O_3 by approximately 6% to 7%. Another assessment tool used in the San Joaquin Valley scaled the San Joaquin Valley 2007 Ozone Plan's *Arvin 2023 Ozone Response Diagram* to estimate the change in ozone per change in NO_x emissions. Using this information and scaling the 267 tpy of NO_x emissions from the proposed modification would result in O_3 increases well below 1 ppb.

8.5 Class I Area Analysis

8.5.1 Air Quality Related Values

The four nearest Class I areas are all within 100km of the project site and are listed below:

- Yolla Bolly – Middle Eel Wilderness Area (57 km)
- Thousand Lakes Wilderness (62 km)
- Lassen National park (64 km)
- Caribou Wilderness Area (89 km)

There are five additional areas within 200 km: Marble Mountain Wilderness Area (116 km), Redwood National Park (147km), Lava Beds National Monument (148 km) and South Warner Wilderness Area (192km).

Based on the most recent Federal Land Managers' Air Quality Related Values (AQRV) Work Group (FLAG) (2010) published guidance, the following screening approach is used to determine whether a more refined Class I Air Quality Analysis is required. This approach only applies to projects located more than 50 km from a Class I area, and it requires adding all of the visibility-related emissions (SO_2, NO_x, PM_{10} and sulfuric acid mist) from a project (based on 24-hour maximum allowable emissions expressed in units of tpy), known as *Q*, and dividing *Q* by the distance *D* between the project and Yolla Bolly, the nearest Class I area. If the result (*Q*/*D*) is less than 10, the project is presumed to have negligible impacts to Class I AQRVs. Table 8.5-1 shows that the project's Q/D is 5.39, well below the FLAG screening criteria. Therefore, no further Class I AQRV analysis is required.

Table 8.5-1 Summary of Q/D Analysis

Project parameter	Value
NOx Emissions Increase (tpy)	254 (1)
SO2 Emissions Increase (tpy)	9.78 (2)
PM10 Emissions Increase (tpy)	39.1 (3)
H2SO4 Emissions Increase (tpy)	4.12 (4)
Q = project Emissions Increase (tpy) = (1) + (2) + (3)+ (4)	307
D= Distance to Closest Class I Area (km)	57
Q/D (tpy/km)	5.39
Q/D Threshold (tpy/km)	10

8.5.2 Class I Increment Consumption Analysis

EPA requires an analysis addressing Class I increment impacts for applicable pollutants, regardless of the results of the Class I AQRV analysis. The analysis for annual NO_2 and PM_{10} and for PM_{10} 24-hour was included in the original application submitted in 2007. Based on the results, EPA did not require updated modeling to be submitted with the 2010 PSD application because of the very low predicted impacts. The applicant provided a $PM_{2.5}$ Class I increment analysis in *Updated Air Dispersion Modeling Analysis* (May 2012) for Yolla Bolly, the closest Class I area, because this would provide the most conservative results. The applicant used the original CALPUFF results from the *Original PSD Application* (May 2007) and the CALPUFF post processing programs. To obtain $PM_{2.5}$ concentrations, coarse PM, sulfate, and nitrate fractions were removed from the post-processing originally used to develop PM_{10} concentrations. The results are presented in Table 8.5-2.

SPI's application was complete on October 4, 2010. There have been no changes in actual emissions of $PM_{2.5}$ from any major stationary source on which construction commenced after October 20, 2010, the major source baseline date for $PM_{2.5}$, for purposes of analyzing $PM_{2.5}$ increment consumption here. Also, no source has triggered the minor source baseline date in the area at issue. Therefore, for purposes of this Class I $PM_{2.5}$ increment analysis, we consider only SPI- Anderson's increment consumption. Because

SPI- Anderson's impacts are much less than the Class I SILs, and the Class I SILs are much lower than the increments, SPI- Anderson's maximum impacts are well below the $PM_{2.5}$ increments. Therefore, the applicant has demonstrated that the project will not cause or contribute to any Class I PSD increment violation for $PM_{2.5}$. Additionally, NO_2 and PM_{10} impacts are well below their respective significant impact levels; therefore, the applicant has demonstrated the project will not cause or contribute to any Class I violation for PM_{10} or NO_2.

Table 8.5-2: SPI- Anderson Class I Increment Impacts at Two Closest Class I Areas

Class I Area	Pollutant, Averaging Time	Project Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Class I PSD Increment, ($\mu g/m^3$)
Yolla Bolly-Middle Eel Wilderness	NO_2, annual	0.0006	0.1	2.5
	$PM_{2.5}$, 24-hour	0.012	0.07	2
	$PM_{2.5}$, annual	0.0006	0.06	1
	PM_{10}, 24-hour	0.06	0.3	8
	PM_{10}, annual	0.002	0.2	4
Thousand Lakes Wilderness	NO_2, annual	0.0009	0.1	2.5
	PM_{10}, 24-hour	0.018	0.3	8
	PM_{10}, annual	0.001	0.2	4

Source: For NO_2 and PM_{10} impacts: Original PSD Application, Table 5-3 pdf.48. For $PM_{2.5}$ impacts: Updated Air Dispersion Modeling Analysis, p.6pdf.6.

9. Additional Impact Analysis

In addition to assessing the ambient air quality impacts expected from a proposed new source, the PSD regulations require that EPA evaluate other potential impacts on 1) soils and vegetation; 2) growth; and 3) visibility impairment. 40 CFR § 52.21(o). The depth of the analysis generally depends on existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the source's impact area.

9.1 *Soils and Vegetation*

The additional impact analysis includes consideration of potential impacts to soils and vegetation associated with the SPI- Anderson emissions. 40 CFR § 52.21(o). This component generally includes:

- a screening analysis to determine if maximum modelled ground-level concentrations of project pollutants could have an impact on plants; and
- a discussion of soils and vegetation that may be affected by proposed project emissions and the potential impacts on such soils and vegetation associated with such emissions.

The proposed project will be within the physical footprint of disturbed land that is part of the existing facility operations of the SPI- Anderson sawmill parcel located in Shasta County, California. The applicant presented its discussion of potential impacts on soils and vegetation as part of its PSD application and supplemental application information (from 2007 through 2012 submittals) and its biological review information (from 2007 and 2010). This information is further discussed below regarding the modification's potential deposition on soils and the project's modeled impacts compared to EPA's screening concentrations and secondary NAAQS.

The potential impact on soils from air pollutants through deposition is presented in the 2007 application (Section 5.0) as part of the Class I AQRV analysis. Additionally, the applicant reviewed the U.S. Department of Agriculture Natural Resources Conservation Service's Web Soil Survey[8]; soils in the area had pH ratings of between 5.3 and 6.5. A current review of the same area indicates that the same soil types (primarily various types of loam with some cobbly alluvial areas) and pH (5.3 to 6.5) are present. Then, as now, the modeled deposition fluxes of nitrogen and sulfur attributable to the project are unlikely to alter or influence the pH of soils in the area.

With respect to the April 2010 updated biological review, the applicant included an expanded project study area beyond the original 2007 evaluation. Soil characteristics of the habitat of the federally listed plant species, the slender Orcutt grass, are described. Its general habitat includes vernal pools (and similar habitat), reservoir edges of stream floodplains, clay soils with seasonal inundation in valley grassland to coniferous forest or sagebrush scrub. Likewise, it is not expected that the project's emissions will adversely affect the habitat of this species.

The applicant's May 2012 application supplement presents an updated air dispersion modeling analysis from its 2010 application update. Project impacts are presented for normal project-only (refer to May 2012, Table 3) and startup and shutdown project-only (refer to May 2012, Table 6) modeling results.[9] The project's SO_2, NO_2 and CO concentrations were compared to EPA screening concentrations in EPA's "Screening procedure for the Impacts of Air pollution Sources on plants, Soils and Animals" (1980)[10]. The screening procedure is used as a tool to identify if the project could have an impact on plants, soils, and animals. The project's impacts do not exceed the screening concentrations for these pollutants. Table 9.1-1 summarizes this information.

[8] Web Soil Survey: http://websoilsurvey.nrcs.usda.gov

[9] Tables 4 and 6 of the May 2012 correspondence were not relied upon because these tables refer to the State and local permit process, which rely on the State ambient air standards; Tables 3 and 5 are relevant for the federal PSD permit process.

[10] "Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals," EPA 450/2-81-078, December 1980.

Table 9.1-1: Project Maximum Concentrations and EPA Guidance Levels for Screening Concentrations for Ambient Exposures

Criteria pollutant, Guidance Averaging Time	EPA Screening Concentration ($\mu g/m^3$)	Modeled Maximum Concentrations ($\mu g/m^3$)	Model Averaging Time
SO_2, 1-Hour	917	1.67	1 hour
SO_2, 3-Hours	786 (0.30 ppm)	1.55 (0.0006 ppm)	3 hour
SO_2, Annual	18	0.07	Annual
NO_2, 4-Hours	3,760	40.0	1 hour
NO_2, 8-Hours	3,760	40.0	1 hour
NO_2, 1-Month	564	40,0	1 hour
NO_2, Annual	94 (0.05 ppm)	1.35 (0.0007 ppm)	Annual
CO, Weekly	1,800,000	212	8 hour

The project's impacts were also compared to the secondary NAAQS. For most types of soils and vegetation, ambient concentrations of criteria pollutants below the secondary NAAQS will not result in harmful effects because the secondary NAAQS are set to protect public welfare, including animals, plants, soils, and materials. The modeled maximum concentrations of SO_2, NO_2, $PM_{2.5}$, and PM_{10} are also significantly below the secondary NAAQS that have been established by EPA:[11]

Table 9.1-2: Project Maximum Concentrations and Secondary NAAQS Standards

Pollutant, Averaging Time	Secondary NAAQS ($\mu g/m^3$)	Modeled Maximum Concentrations ($\mu g/m^3$)
SO_2, 3-hour	1,300 (0.5 ppm)	1.55 (0.0006 ppm)
NO_2, Annual	100 (0.053 ppm)	1.35 (0.0007 ppm)
PM_{10}, 24-hour	150	3.36
$PM_{2.5}$, 24-hour	35	3.11
$PM_{2.5}$, Annual	15	0.27

In sum, based on our consideration of the information and analysis provided by the applicant, and other relevant information, we do not believe that emissions associated with the project will generally result in adverse impacts to soils or vegetation.

[11] EPA has not promulgated a secondary NAAQS for CO.

9.2 *Visibility Impairment*

The additional impact analysis also evaluates the potential for visibility impairment (*e.g.*, plume blight) associated with SPI- Anderson. 40 CFR § 52.21(o). Using procedures from EPA's Workbook for Plume Visual Impact Screening and Analysis[12], the potential for visibility impairment is characterized for:

- Class I areas located within 50 km of the proposed SPI- Anderson modification; and
- Class II areas identified as potentially sensitive state or federal parks, forests, monuments, or recreation areas.

There are no Federal Class I areas located within 50 km of the project site; the nearest Class I area is Yolla Bolly-Middle Eel (57 km away). The next nearest Class I area is Thousand Lakes Wilderness Area (62 km away). For nearby Class II areas or recreation areas, the applicant evaluated visibility impairment for the following within 50 km of the project site:

- Sacramento River National Wildlife Refuge (NWR) 38.8 km at its closest point;
- Whiskeytown National Recreation Area (NRA) 18.3 km at its closest point.

EPA has not yet established a quantitative visibility impairment threshold for Class II areas (similar to what exists for Class I areas). We requested that the applicant conduct a Level 1 VISCREEN analysis, and, if necessary, a Level 2 screening analysis for these two areas.

For Whiskeytown NRA and Sacramento River NWR, the impact of the project on visibility impairment, also known as plume blight, was assessed. The EPA VISCREEN screening model was used to estimate visibility impairment to these two areas from the project's emissions. Effects of plume blight are assessed as changes in plume perceptibility (ΔE) and plume contrast (C_p) for sky and terrain backgrounds. A Level 1 analysis, using default meteorological data and no site-specific conditions, was conducted. Because the results of the Level 1 screening analyses indicated that some of the screening criteria were exceeded, a Level 2 analysis was conducted for both areas. A detailed discussion of the VISCREEN plume blight impact analysis is presented in the applicant's Class II Area Visibility analysis submitted by the applicant to EPA in July 2012.

The results of the Level 2 VISCREEN modelling runs are presented below in Tables 9.2-1, 9.2-2, 9.2-3 and 9.2-4. The VISCREEN results are presented for the two default worst case theta angles – theta equal to 10 degrees representing the sun being in front of an observer, and theta equal to 140 degrees representing the sun being behind the observer. A negative plume contrast means the plume has a darker contrast than the background sky.

[12] "Workbook for Plume Visual Impact Screening and Analysis (Revised)", EPA, EPA–454/R–92–023, 1992.

Table 9.2-1: Whiskeytown NRA Class II VISCREEN Modelling Results of Changes in Plume Perceptibility (ΔE)

Background	Distance (km)	Plume Perceptibility (ΔE)		
		Theta 10	Theta 140	Criteria
Sky	37.1	0.408	0.24	2.00
Terrain	37.1	0.911	0.187	2.00

Table 9.2-2: Whiskeytown NRA Class II VISCREEN Modeling Results of Changes in Plume Contrast (C_p)

Background	Distance (km)	Plume Contrast (C_p)		
		Theta 10	Theta 140	Criteria
Sky	37.1	0.005	-0.003	0.05
Terrain	37.1	0.007	0.001	0.05

Table 9.2-3: Sacramento River NWR Class II VISCREEN Modelling Results of Changes in Plume Perceptibility (ΔE)

Background	Distance (km)	Plume Perceptibility (ΔE)		
		Theta 10	Theta 140	Criteria
Sky	50.0	0.724	0.47	2.00
Terrain	38.9	1.209	0.104	2.00

Table 9.2-4: Sacramento River NWR Class II VISCREEN Modelling Results of Changes in Plume Contrast (C_p)

Background	Distance (km)	Plume Contrast (C_p)		
		Theta 10	Theta 140	Criteria
Sky	50.0	0.01	-0.006	0.05
Terrain	38.9	0.008	0.001	0.05

The results from the VISCREEN model show that changes in plume perceptibility and plume contrast for sky and terrain backgrounds inside these two areas are below the criteria thresholds. Therefore, the plume would not be perceptible against a sky or terrain background.

Consequently, EPA guidance indicates that these results may be used to determine that the project will not contribute to visibility impairment, and no further analysis is required.

9.3 *Growth*

The growth component of the additional impact analysis involves a discussion of general commercial, residential, industrial, and other growth associated with SPI- Anderson. 40 CFR § 52.21(o). This analysis considers emissions generated by growth that will occur in the area due to the modification. In conducting this review, we focus on residential, commercial and industrial growth that is likely to occur to support the source under review including employment expected during construction and operations and potential growth impacts associated with this employment, this as impacts to local population and housing needs

EPA does not expect this project to result in any significant growth. Construction of the proposed cogeneration unit would span between 14 and 18 months. Laydown and temporary worker parking areas will be located within the existing facility property boundary. During construction approximately 40 temporary workers would be added, however this demand would be mitigated by the use of existing employees.

Once the cogeneration unit is operational, the facility expects to employ approximately eight additional workers. The project will utilize existing roads and infrastructure, and no additional roads or transportation infrastructures are proposed for construction. We do not expect the new cogeneration unit to cause significant growth in the area.

10. Endangered Species

Pursuant to Section 7 of the Endangered Species Act (ESA), 16 U.S.C. 1536, and its implementing regulations at 50 CFR Part 402, EPA is required to ensure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat. EPA has determined that this PSD permitting action is subject to ESA Section 7 requirements.

The construction activities resulting from the proposed modification will occur on SPI-Anderson's existing facility footprint. All storm water runoff will be contained on the site. Power lines to be constructed between the new transformer and the existing switch yard will be strung overhead. It is anticipated that there will be three sets of suspended wooden poles to span the distance between the existing switch yard and the transformer to be located near the turbine building.

SPI has confirmed that construction activities will not occur within 100 feet of the elderberry shrubs that are in the Pacific Gas and Electric power line Right of Way. The nearest construction activity to the existing elderberry plants will be the erection of the electrical power poles at the existing electrical sub-station which are 137 feet away from the nearest elderberry shrub. The main construction area, where the boiler, turbine building, fuel shed, electrical substation cooling tower, and ESP will be built, is approximately 1,000 feet from the nearest elderberry shrub.

EPA concludes that the project will have no likely adverse effect on any endangered or threatened species or designated critical habitat. Discussions with the United States Fish and Wildlife Service support EPA's conclusion.

11. Environmental Justice Screening Analysis

Executive Order 12898, entitled "Federal Actions To Address Environmental Justice in

Minority populations and Low-Income populations," states in relevant part that "each Federal agency shall 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." Section 1-101 of Exec. Order 12898, 59 Fed. Reg. 7629 (Feb. 16, 1994).

This AAQIR concludes that the proposed modification will not cause or contribute to air quality levels in excess of health standards for the pollutants regulated under EPA's proposed PSD permit for the proposed modification, and that the project will not result in disproportionately high and adverse human health or environmental effects with respect to these air pollutants on populations residing near the SPI- Anderson site, or on the community as a whole.

12. Clean Air Act Title V (Operating Permit)

The SPI Anderson facility already must comply with a Title V Operating Permit, SCAQMD Permit #94VP18c. After the proposed cogeneration unit is constructed, SCAQMD Permit #94VP18c will need to be revised to appropriately reflect the facility's current operations. The SCAQMD has jurisdiction to issue the Title V Operating Permit for SPI- Anderson.

13. Comment Period, Procedures for Public Hearing Requests, Final Decision, and EPA Contact

The comment period for EPA's proposed PSD permit for the project begins on September 12, 2012. Pursuant to 40 CFR 124.12, EPA has discretion to hold a Public Hearing if we determine there is a significant amount of public interest in the proposed permit. Requests for a Public Hearing must state the nature of the issues proposed to be raised in the hearing. If a Public Hearing is to be held, a public notice stating the date, time and place of the hearing will be made at least 30 days prior to the hearing. Reasonable attempts will be made to notify directly any person who has commented on this proposal of any pending Public Hearing, provided contact information has been given to the EPA contact person listed below.

Any interested person may submit written comments or request a Public Hearing regarding EPA's proposed PSD permit for this modification. All written comments and requests on EPA's proposed action must be received by EPA via e-mail by October 17, 2012, or postmarked by October 17, 2012. Comments or requests must be sent or delivered in writing to Omer Shalev at one of the following addresses:

E-mail: R9airpermits@epa.gov

U.S. Mail: Omer Shalev (AIR-3)
U.S. EPA Region 9

75 Hawthorne Street
San Francisco, CA 94105-3901
Phone: (415) 972-3538

Comments should address the proposed permit modification and facility, including such matters as:

1. The Best Available Control Technology (BACT) determinations;
2. The effects, if any, on Class I areas;
3. The effect of the proposed facility on ambient air quality; and
4. The attainment and maintenance of the NAAQS.

All information submitted by the applicant is available as part of the administrative record. The proposed air permit, fact sheet/ambient air quality impact report, permit application and other supporting information are available on the EPA Region 9 website at http://www.epa.gov/region09/air/permit/r9-permits-issued.html#pubcomment. The administrative record may also be viewed in person, Monday through Friday (excluding federal holidays) from 9:00 AM to 4:00 PM, at the EPA Region 9 address above. Due to building security procedures, please call Omer Shalev at (415) 972-3538 at least 24 hours in advance to arrange a visit. Hard copies of the administrative record can be mailed to individuals upon request in accordance with Freedom of Information Act requirements as described on the EPA Region 9 website at http://www.epa.gov/region9/foia/.

EPA's proposed PSD permit for the proposed modification and the accompanying fact sheet/ambient air quality impact report are also available for review at the Shasta County Air Quality Management District at 1855 Placer St., Suite 101 in Redding, CA 96001, and the Redding Public Library at 1100 Parkview Ave. in Redding, CA 96001.

All comments that are received will be included in the public docket without change and will be available to the public, including any personal information provided, unless the comment includes Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Information that you consider CBI or otherwise protected should be clearly identified as such and should not be submitted through e-mail. If you send e-mail directly to the EPA, your e-mail address will be automatically captured and included as part of the public comment. Please note that an e-mail or postal address must be provided with your comments if you wish to receive direct notification of EPA's final decision regarding the permit.

EPA will consider all written and oral comments submitted during the public comment period before taking final action on the PSD permit modification and will send notice of the final decision to each person who submitted comments and contact information during the public comment period or requested notice of the final permit decision. EPA will respond to all substantive comments in a document accompanying EPA's final permit decision.

EPA's final permit decision will become effective 30 days after the service of notice of the decision unless:

1. A later effective date is specified in the decision; or
2. The decision is appealed to EPA's Environmental Appeals Board pursuant to 40 CFR Part 124.19; or
3. There are no comments requesting a change to the proposed permit decision, in which case the final decision shall become effective immediately upon issuance.

If EPA issues a final decision granting the PSD permit for this modification, and there is no appeal, construction of the modification may commence, subject to the conditions of the PSD permit and other applicable permit and legal requirements.

If you have questions, please contact Omer Shalev at (415) 972-3538 or e-mail at R9airpermits@epa.gov. If you would like to be added to our mailing list to receive future information about this proposed permit decision or other PSD permit decisions issued by EPA Region 9, please contact Omer Shalev at (415) 972-3538 or send an e-mail to R9airpermits@epa.gov, or visit EPA Region 9's website at http://www.epa.gov/region09/air/permit/psd-public-guidelines.html.

14. Conclusion and Proposed Action

EPA is proposing to modify the PSD permit for SPI-Anderson facility owned and operated by SPI. We believe that the proposed project will comply with PSD requirements including the installation and operation of BACT, and will not cause or contribute to a violation of the NAAQS, or of any PSD increment. We have made this determination based on the information supplied by the applicant and our review of the analyses contained in the permit application. EPA will provide the proposed permit and this AAQIR to the public for review, and make a final decision after considering any public comments on our proposal.

Appendix A- Greenhouse Gas Emissions Estimates

Boiler- Biomass And Natural Gas Emission Rates

Pollutant	Biomass Emission Factor (Heat Input)i		Natural Gas Emission Factor (Heat Input)i		Heat Input for Unit (MMBtu/hr)	Biomass Emission Rate	Natural Gas Emission
	(kg/MMBtu)	(lb/MMBtu)	(kg/MMBtu)	(lb/MMBtu)		(lb/hr)	(lb/hr)
CO_2	93.8	207	66.83	147.3	468	96,876	68,952
CH_4	0.032	0.0705	0.001	0.002205	468	33	1
N_2O	0.0042	0.00926	0.0001	0.000220	468	4	0

Discussion: EPA's *Deferral for CO_2 emissions from Bioenergy and Other Biogenic Sources under the Prevention of Significant Deterioration and Title V programs* (76 FR 43490 July 20, 2011) applies to this modification. Therefore, the determination of PSD applicability for GHG will exclude CO_2 emissions from the burning of biomass fuel for this proposed modification. The boiler is allowed to burn natural gas during startup and shutdown, but the proposed PSD permit limits the annual heat input from natural gas to not exceed 10% of total heat input on an annual basis. Assuming 8,760 hours of operation per year, the total maximum non-deferred emissions of GHG from this boiler are:

Boiler Worst-Case Annual Emission Rate

Pollutant	Biomass Emission Rate (lb/hr)	Natural Gas Emission Rate (lb/hr)	Biomass Operation (hours)	Natural Gas Operation (hours)	Biomass Emissions (tpy)	Natural Gas Emissions (tpy)	Global Warming potential	CO_2e
CO2	96,876	68,952	7,884	876	381,885	30,200.99	1	412,086
CH4	33	1	7,884	876	130	0.45	21	2,741
N2O	4	0	7,884	876	17	0.05	310	5,310
Total	-	-	-	-	-	-	-	**420,137**

Emergency Engine Emission Rate

Pollutant	Natural Gas Emission Rate (lb/hr)	Natural Gas Operation (hours)ii	Natural Gas Emissions (tpy)	Global Warming potential	CO_2e
CO2	507	500	126.71	1	127
CH4	0.008	500	0.00	21	0
N2O	0.001	500	0.00	310	0
Total	-	-	-	-	**127**

Total Boiler CO_2e without CO_2 from biomass

= 2,741 (from CH_4) + 5,310 (from N_2O) + 30,201 (from Natural Gas CO_2)

= 38,252 CO_2e

Total Emergency Engine CO_2e from Natural Gas
= 127 CO_2e

Total Project CO_2e
= **Boiler CO2e + Emergency Engine CO2e**
= **38,252 CO_2e +127 CO_2e**
= 38,379 CO_2e

As calculated above, total annual CO_2e emissions excluding CO_2 are 38,379 tpy of CO_2e, which is below the GHG "subject to regulation" threshold of 75,000 tpy. As a result, the modification is not subject to BACT requirements for GHG.

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[i] The kg/MMBtu emission factors for combustion of wood and wood residual solid biomass fuel, as well as natural gas, are from 40 CFR Part 98, Tables C-1 and C-2; 1kg= 2.2046 lb
[ii] The emergency engine is limited to 100 hours of nonemergency use per year. The table conservatively assumes 500 hours of use per year.

Excerpt 3

SPI Anderson Final Response to Comments, dated February 19, 2013 ("RTC"), AR VI.03

U.S. Environmental Protection Agency
February 2013

Responses to Public Comments on the Proposed PSD Permit Major Modification for Sierra Pacific Industries- Anderson Division

Contents

I. Introduction

The U.S. Environmental Protection Agency, Region 9 (EPA) proposed to issue a major modification of the Prevention of Significant Deterioration (PSD) permit to Sierra Pacific Industries (SPI) for the SPI-Anderson Division facility (Facility) on September 14, 2012. The public comment period for the proposal (Proposed Permit)[1] began on September 13, 2012 and closed on October 17, 2012. During the public comment period EPA took comments on the proposed permit modification.

The purpose of this document is to respond to every significant issue raised in the public comments received during the public comment period and explain what changes have been made in the final permit (Final Permit) as a result of those comments.

EPA announced the public comment period through a public notice published in the *Record Searchlight* (in English only) on September 14, 2012 and on Region 9's website (in English) on September 13, 2012. EPA also distributed the public notice to the necessary parties in accordance with 40 CFR Part 124, including notices sent by mail on September 12, 2012 and email on September 13, 2012. Parties notified by EPA included agencies, organizations, and public members for whom contact information was obtained through a number of different methods, including requests made directly to EPA through Region 9's website (or through other means) from parties seeking notification regarding permit actions in California, within the Shasta County Air Quality Management District (District), within Shasta County; and other parties known to EPA that may have an interest in this action. EPA provided notice to numerous government agencies in accordance with 40 CFR Part 124, including, but not limited to, the California Energy Commission (CEC), the District, and other local neighboring air districts.

The Administrative Record for the Proposed Permit modification was made available at EPA Region 9's office. EPA also made the Proposed Permit, the Fact Sheets and Ambient Air Quality Impact Report (AAQIR) and other supporting documents available on Region 9's website.

During the public comment period, EPA received 15 comment letters and three requests for a public hearing. Responses to the public comments received are available in the following sections of this document.

EPA did not receive comments regarding the sufficiency of modeling for pollutants projected to have impacts below significant impact levels (SILs) for $PM_{2.5}$. However, because of recent actions by EPA and a recent decision from the United States Court of Appeals for the District of Columbia Circuit, *Sierra Club v. EPA*, No. 10-1413, 2013 WL 216018 (Jan. 22, 2013), we are supplementing our analysis of the Project's impacts on the annual $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS) and PSD increments for $PM_{2.5}$.

SILs are numeric values that may be used to evaluate whether a proposed major source or modification will cause or contribute to a violation of NAAQS or PSD increment. *See* 72 Fed.

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[1] We note that EPA's permitting regulations at 40 CFR Part 124 refer to proposed permits as "draft permits." *See* 40 CFR 124.6.

Reg. 54112, 54138 (Sept. 21, 2007). The EPA has observed that if the source's modeled impacts are below the level of the SIL for the relevant pollutant, this showing is often sufficient to demonstrate that the source will not cause or contribute to a violation of the NAAQS. 72 FR at 54139. However, in the preamble of the final rule establishing SILs for $PM_{2.5}$, EPA cautioned that there can be circumstances where a showing that the air quality impact of a proposed source is less than the $PM_{2.5}$ SILs is not sufficient by itself to demonstrate that a source will not cause or contribute to a violation of the NAAQS or increment. 75 FR 64864, 64892-94 (October 20, 2010); *see also Sierra Club*, 2013 WL 216018, at 5 (granting EPA request to vacate and remand regulatory text at 40 CFR 52.21(k)(2) because it does not allow permitting authorities the discretion to require a cumulative impact analysis, notwithstanding that the source's impact is below the SIL, where there is information that shows the proposed source would lead to a violation of the NAAQS or increments).

The AAQIR and further analysis included here show that the Project does not present the type of situation in which existing air quality in the affected area is already close to the NAAQS or PSD increment, such that a source with an impact below the $PM_{2.5}$ SILs could nevertheless cause or contribute to a violation of the $PM_{2.5}$ NAAQS or increment. As explained below, EPA's conclusions that the Project will not cause or contribute to a violation of the NAAQS are supported by the background concentrations of $PM_{2.5}$ in the area, modeling, and other factors. A cumulative impact analysis was not considered to be necessary to this conclusion.

Table 8.4-2 of the AAQIR shows that emissions from the Project are predicted to be below the SIL for $PM_{2.5}$ (annual). *See* online docket #III.02, *SPI-Anderson Ambient Air Quality Impact Report_12SEP12* at 33. Table 8.2-1 of the AAQIR provides the maximum background concentrations of $PM_{2.5}$ that may be affected by the Project's emissions. *See* AAQIR at 28. For $PM_{2.5}$ (annual), where the Project's modeled impact was below the SIL, the maximum background concentrations measured in the area are well below the NAAQS. The difference between the $PM_{2.5}$ (annual) background concentration in the area and the NAAQS is 9.7 $\mu g/m^3$ which is significantly greater than the $PM_{2.5}$ annual SIL of 0.30 $\mu g/m^3$. As noted in Section 8.4.3.2 of the AAQIR, adding the Project's predicted impact of 0.27 $\mu g/m^3$ to the existing background concentration yields a total concentration of 5.57 $\mu g/m^3$ which is still less than one third of the NAAQS and leaves roughly 9.4 $\mu g/m^3$ remaining before the $PM_{2.5}$ (annual) NAAQS is threatened. *See* AAQIR at 35.

In addition, other than SPI-Anderson's projected emissions increases, there have been no actual emissions changes of $PM_{2.5}$ from any new or modified major stationary source on which construction commenced after October 20, 2010, the major source baseline date for $PM_{2.5}$ according to 40 CFR 52.21 (b)(14)(i)(c). *See* online docket #III.02, *SPI-Anderson Ambient Air Quality Impact Report_12SEP12* at 34. Since the only source to consume $PM_{2.5}$ increment in the area is SPI-Anderson, the applicant appropriately considered only the allowable emissions increase from the SPI-Anderson project in the annual $PM_{2.5}$ increment analysis. Moreover, the predicted impact of the source for the $PM_{2.5}$ (annual) NAAQS is well below the increment in the area.

The applicant's analysis also conservatively assumed that all PM emissions were comprised of $PM_{2.5}$ emissions, and used PM emissions data as input to the modeling. As shown in Table 1.6-1 of EPA's *AP-42 Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources*, $PM_{2.5}$ emissions from wood fired boilers equipped with electrostatic precipitators are expected to be roughly 65% of all filterable particulate emissions. Thus, actual $PM_{2.5}$ impacts from the Project are expected to be considerably lower than those indicated in the modeled results and would not, therefore, be expected to cause or contribute to a violation of the $PM_{2.5}$ (annual) ambient air quality standard or increment.

II. EPA's Responses to the Public's Comments

This section summarizes all significant public comments received by EPA and provides our responses to the comments. The full text of all public comments and many other documents relevant to the permit can be accessed online through EPA's website at http://www.epa.gov/region09/air/permit/r9-permits-issued.html.

Comments Submitted by Mr. Russell Wade

1. **Comment:** Our planet is heating as we put more and more carbon into the air trapping the infra-red rays of the sun and dehydrating our forests in the northen calif. 2011 set record temperatures in 15,000 areas in the U.S. we have had over a hundred square miles of forests burn, (this year) putting up even more carbon- just as Sierra Pacific clear cuts raise termperatures- a co-generation plant is a good idea for creating local energy- putting 300,000 tons of CO_2 in the air per year is stupid- this plant could be designed so the carbon output can be sequested. There is a big denial about the facts surrounding global warming we need to be reversing our carbon output-as presently designed the plant is only going to boost our carbon output.

   Response: The commenter has suggested that the new cogeneration unit should be required to sequester the carbon dioxide (CO_2) emissions resulting from the combustion of various fuels. As noted in the Ambient Air Quality Impact Report (AAQIR), the modification was not subject to best available control technology (BACT) for the pollutant greenhouse gases (GHG) which is comprised of six gases, including CO_2. Although the proposed modification identifies an increase in GHG emissions that exceeds the "subject to regulation" threshold of 75,000 tpy CO_2e and GHG significance rate of 0 tpy, EPA's *Deferral for CO_2 emissions from Bioenergy and Other Biogenic Sources under the Prevention of Significant Deterioration and Title V programs* (76 FR 43490 July 20, 2011) applies to this project.

Comments Submitted by Mr. C.T. Carden

2. **Comment:** I have lived in N. Calif since 1964- in the forested areas. Our woods are crambed full of vegetation waiting for a forest fire. There is a great need to deforest (clean up) many of the chocked areas. S.P.I (Sierra Pac.) can help save (manage) these areas by burning ("hog fuel") at their Anderson Co-Gen plant- Everybody wins with this plant for gen. electricity. We need electricity and cleaning up the forest at the same time. Please allow the And. Calif (Riverside Ave.) plant to build the co-gen. plant for the benefit of everybody. We need the jobs too. Thank you.

   Response: The modification allows for the construction of a cogeneration unit at the existing SPI-Anderson facility. Fuels to be combusted in the new unit will be restricted to biomass and natural gas as detailed in the final permit.

Comments Submitted by Ms. Joy L. Newcom

3. Comment: Please Please Please DO NOT PERMIT Sierra Pacific I. Please Please Please outlaw and shut them down. Their ATROCIUS Air Quality in this sink-bowl surrounded by 10,000+ foot mountain ranges, absolutely, cannot, handle any more particulate or chemical pollution!!! We've become way too populated with retired, disabled, infants, children and sensitive populations. S.P.I. need to build its plant in Nevada, or Sand, CA (by desalination plant.)

Response: EPA's permit action is for granting SPI the authority to construct new emission units at the existing SPI-Anderson location. Shasta County is in attainment or unclassifiable for all pollutants regulated under the PSD program. Moreover, The Clean Air Act identifies two types of NAAQS. Primary standards provide public health protection, including protecting the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. In the AAQIR for this action, EPA demonstrated air pollution emissions from the new cogeneration unit will not cause or contribute to violations of any NAAQS or any applicable PSD increments for the pollutants regulated under the PSD program.

Comments Submitted by Mr. Marshall Knauss

4. Comment: I live across the highway from S. P. in Anderson and the last week or so I've noticed alot of brown smoke coming out of the generating facility they already have. My question is have they only started running it in the day time recently. I don't ever remember seeing the smoke. I figured they only ran at night .I would have to be against it if we will be increasing the amount of brown smoke--- SMOG-- IF YOU WILL INTO THE AIR.

Response: EPA's permit action is for granting SPI the authority to construct new emission units at the SPI- Anderson location. As stated in response to comment#3, this modification is not expected to cause or contribute to any NAAQS violation. EPA is not aware of increased air emissions at the SPI-Anderson facility at this time. However, after discussions with the District regarding this issue, EPA received the following information from the District on October 1, 2012:

> [T]here is a small 6 [megawatt] cogeneration plant located adjacent to SPI, near the northwest corner. This facility has undergone some retrofitting and is currently undergoing start-up testing. An Authority to Construct for Anderson Plant, LLC (Kiara Solar) was issued by the District on 10/1/10. This plant was included in the emission modeling during SPI's application and EIR process.
>
> The reason for this notification is to prevent any confusion… that could potentially arise from a passer by who might think that this is the SPI plant. This source is very visible from HWY 273 and people do confuse it with the SPI Anderson plant from time to time.

Comments Submitted by Mr. Ken Archuleta

5. Comment: I am in favor of granting the permit modification to allow construction of a 31 megawatt power plant.

Response: EPA's permit action is for granting SPI the authority to construct a new 31 MW emission unit at the SPI- Anderson location, an existing PSD major stationary source of air emissions.

Comments Submitted by Mr. Ed W. Coleman

6. Comment: Received your latest info on the "sierra Pacific Ind." Anderson Calif. Division modification permit! They have been nothing short of a major polluter in the past, and have shown gross lack of compliance! We proved this with our own "Citizens for Cleaner Air" contract with a private testing company! If the USEPA uses the proper pollution scale, we feel that environmental justice is served!

Response: It is unclear from the commenter's statement what pollution scale should be considered in relation to this facility with regard to the PSD program. EPA requested public comment on its proposed action relating to the major modification of the PSD permit for SPI- Anderson. EPA's proposed PSD permit would grant conditional approval, in accordance with the PSD regulations (40 CFR 52.21), to SPI to construct and operate a new cogeneration unit at its existing Anderson facility. The AAQIR that serves as the basis for this action which demonstrates that the facility as modified would not cause or contribute to a violation of the NAAQS. As discussed in response to comment# 3, the NAAQS were set to provide public health protection, including protecting the health of "sensitive" populations such as asthmatics, children, and the elderly.

Comments Submitted by Ms. Mary Olswang

7. Comment: I am writing with concerns about the SPI proposed cogeneration plant in Anderson, CA, Shasta County. I oppose the project.

It is estimated this plant will emit 330,000 tons of greenhouse gases annually. It is counter productive for the EPA to approve such projects while also supporting clean air policies. In this age, we cannot afford to dump more toxic waste into our atmosphere.

Are there not alternative to disposing of their waste, like composting? Enriched soils can be used for growing new trees.

Response: As stated in the AAQIR, the proposed modification identifies an increase in GHG emissions that exceeds the "subject to regulation" threshold of 75,000 tpy CO_2e and GHG significance rate of 0 tpy. However, EPA's *Deferral for CO_2 emissions from Bioenergy and Other Biogenic Sources under the Prevention of Significant Deterioration and Title V programs* (76 FR 43490 July 20, 2011) applies to this project. Since the non-deferred GHG emissions for this project are 38,252 tpy CO_2e, the modification is not subject to BACT for GHG and a resulting control technology review for GHG was not conducted. The deferral for CO_2 emissions from bioenergy and biogenic sources under the PSD program was applied to those CO_2 emissions that result from the combustion of biomass.

Comments Submitted by Ms. Joan Coleman

8. **Comment:** I wish to express my opposition to the permit before you to build a 31 megawatt wood burning power plant north of Anderson. As you know this will be in addition to the 6 wood burning power plants in Shasta County. The plant will emit about 330,000 tons of greenhouse gases annually. All 6 plants would then be generating about 2.16million tons of greenhouse gases annually. The State says Shasta County already receives 26.5 TON of carbon monoxide released into the air DAILY. It is unreasonable to allow this plant to increase our air pollution The EPA should deny the permit.

   Response: Please see response to comment #7 in regard to GHG emissions.

   The PSD program is intended to protect air quality in "attainment areas", which are areas that meet the NAAQS. The District is currently in attainment of the NAAQS for CO. As stated in the AAQIR, air pollution emissions from the new cogeneration unit will not cause or contribute to violations of any NAAQS or any applicable PSD increments for the pollutants regulated under the PSD permit, including CO.

Comments Submitted by Ms. Heidi Strand of Citizens for Clean Air

9. **Comment:** The commenter states that the cogeneration unit must be issued a "new PSD permit." EPA is clearly violating the intent of Executive Order #12898 with regard to Environmental Justice by circumventing the entire PSD permitting process. The commenter also requested a public hearing on a number of issues, ranging from how BACT is applied to information with regard to environmental violations at the facility and air pollution credits available in Shasta County. The commenter states that EPA disenfranchises members of the public from the public process by not holding a public a hearing.

   Response: SPI- Anderson is undergoing a physical change and or change in the method of operation that results in a significant emissions increase of several regulated NSR pollutants at the existing major stationary source. This corresponds to the definition of major modification as defined in 40 CFR 52.21(b)(2)(i). The new equipment at the site is being issued a PSD permit. *See* online docket #III.01, *SPI-Anderson Proposed PSD Permit Modification_12SEP12*. EPA is requiring the source to satisfy the requirements under 40 CFR 52.21 as documented in the AAQIR, it is unclear why the commenter believes that EPA is circumventing the PSD permitting process.

   Executive Order 12898, entitled "Federal Actions To Address Environmental Justice in Minority populations and Low-Income populations," states in relevant part that "each Federal agency shall 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." Section 1-101 of Exec. Order 12898, 59 Fed.

Reg. 7629 (Feb. 16, 1994). The AAQIR concluded that the proposed modification will not cause or contribute to air quality levels in excess of health standards for the pollutants regulated under EPA's proposed PSD permit for the proposed modification, and that the project will not result in disproportionately high and adverse human health or environmental effects with respect to these air pollutants on populations residing near the SPI- Anderson site, or on the community as a whole.

EPA reviewed demographic data for the community surrounding the immediate project area prior to proposing the permit and issuing public notification materials in accordance with 40 CFR Part 124. In particular, EPA considered socioeconomic, linguistic isolation, education and other relevant factors to help inform our public outreach activities. Prior to noticing the proposed permit decision, EPA conducted a review of U.S. Census Data to determine whether outreach materials should be provided in a language other than English. EPA's review found that the cities of Anderson and Redding, along with Shasta County had less than 2.5%, 1.5% and 1.5% of all households listed respectively as linguistically isolated. Moreover EPA contacted the local air district to learn whether the district had received complaints, concerns, or requests regarding the publication of public notices in a language other than English for any prior permitting actions. District personnel stated that they had not received such complaints, concerns, or requests. Based on EPA's review and conversations with the local air district, EPA determined that outreach materials would not be translated into another language. EPA's public engagement activities included the mailing of roughly 800 public notices in the area surrounding the SPI- Anderson and in the state of California, emailing roughly 650 recipients and publishing a notification of the Project in the *Record Searchlight* on September 14, 2012. The *Record Searchlight* also published a separate article about the Project modification on September 22, 2012..

Pursuant to 40 CFR 124.12, EPA must hold a public hearing if it, on the basis of requests, determines there is a significant degree of public interest in a draft permit. After distributing the public notice to the necessary parties in accordance with 40 CFR Part 124 and additional members of the public, EPA received comments from 15 members of the public, including the applicant, and three requests for a public hearing. None of the requests for a public hearing demonstrated that there was significant public interest in the Project; therefore EPA did not hold a public hearing. EPA reviewed and responded to all written comments from the public received during the public comment period.

With respect to the comments regarding air pollution credits, the PSD program is intended to protect air quality in "attainment areas", which are areas that meet the NAAQS. The District is currently in attainment or unclassifiable for all of the NAAQS. The PSD permitting program does not require emission offsets, commonly referred to as air pollution credits, to be surrendered prior to construction of an applicable source.

Comments Submitted by Mr. Rob Simpson of Helping Hand Tools

10. Comment: On September 26, Mr. Simpson requested an extension of the public comment period because this is the first time he would provide comments on this type of facility and that the record contained numerous materials that could not be adequately reviewed within the allotted time.

Response: Our September 28, 2012 response is copied below:

Dear Mr. Simpson,

We received your questions regarding the proposed PSD permit modification for SPI-Anderson. Let me first address your request for a public comment period extension. In order for EPA to extend the public comment period beyond the currently scheduled end date of October 17, 2012, a commenter must adequately justify why additional time is required in order to comment on the proposed action. While your request states that there are many documents to review, the number of documents for this project is no different than any other project, and you have not demonstrated why there would be a significantly greater burden to review the documents for this project. Thus, we do not plan to extend the public comment period at this time.

Finally, regarding the application materials, they can be found in the online Docket no. EPA-R09-OAR-2012-0634. The majority of the application information can be found in I.01, but additional important materials are also included in I.03, I.05, I.07, I.08, I.25, I.31, I.33, I.34. Document I.08 contains a Greenhouse Gas emissions estimate and discussion. The other items listed above contain additional emissions estimates, modeling information and other relevant material.

Thank you for your interest in EPA's proposed action. I hope you find this information useful.

11. **Comment:** On October 17, 2012, the commenter requested a public hearing and an extension of the public comment period. The commenter stated that the record is too extensive to review in the allotted time period.

    Response: As we stated in our earlier reply to the commenter's first request for an extension to the public comment period, the size of the record for this project is similar to that for other projects, and the commenter did not demonstrate a significantly greater burden to review the documents for this project. With regard to the commenter's request for a public hearing, please see our response to comment #9 above. We note that none of the three requests for a public hearing demonstrated that there was significant public interest to warrant a public hearing.

12. **Comment:** The commenter stated that EPA only provided an English version of the public notice and that a public notice in Spanish should also have been provided. The commenter claims EPA failed to demonstrate that it notified participants in the State action(s) and the appropriate elected officials. Moreover, the commenter states that the public notice fails to disclose any effect on air quality and the Project's effects in relationship to the NAAQS or at least in gross pollutant weights.

    Response: EPA distributed the public notice to the necessary parties in accordance with 40 CFR Part 124, including notices sent by mail on September 12, 2012 and email on

September 13, 2012 and publication in the *Record Searchlight* on September 14, 2012. Parties notified by EPA included agencies, organizations, and public members for whom contact information was obtained through a number of different methods, including requests made directly to EPA through Region 9's website (or through other means) from parties seeking notification regarding permit actions in California, within the District, within Shasta County; and other parties known to EPA that may have an interest in this action. EPA provided notice to numerous government agencies in accordance with 40 CFR Part 124, including, but not limited to, the CEC, the District, and other local neighboring air districts.

40 CFR Part 124 states that public notice of activities shall be given by mailing a copy of the notice to "the chief executives of the city and county where the major stationary source or major modification would be located" and EPA mailed the public notice to the city manager of Anderson, CA and the Chairman and Clerk of the Shasta County Board of Supervisors. It is unclear what the commenter means by "appropriate elected officials" as EPA mailed officials at the county and city level.

The translation of public notices is not required by 40 CFR Part 124, and EPA determined, after discussing the public notification practices of the District that Spanish translation was not required. Prior to noticing the proposed permit decision, a review of U.S. Census Data in the area found that the cities of Anderson and Redding, along with Shasta County had less than 2.5%, 1.5% and 1.5% of all households listed respectively as linguistically isolated. Moreover, the District stated that it had not received complaints, concerns or requests regarding the publication of public notices in a language other than English for any prior permitting actions.

EPA's public notice included appropriate information as required by the public notice content requirements in 40 CFR 124.10(d). We note that the public notice did state that "[a]ir pollution emissions from the new cogeneration unit will not cause or contribute to violations of any National Ambient Air Quality Standards (NAAQS) or any applicable PSD increments for the pollutants regulated under the PSD permit."

13. **Comment:** The commenter states that the facility apparently requires 7 of the 23 megawatts electricity that it can generate. No state authority has, or is, required to make a determination if the electricity in this location is beneficial to the system. The project will interfere with the development of superior solar and wind alternatives. The commenter also states that a solar component should be considered in the BACT analysis.

Response: EPA, the permit issuer for this project, does not have an obligation to independently investigate all possible power generation alternatives, including a no-build alternative. Further, the Environmental Appeals Board has observed the importance of this limitation on the permit issuer's obligation, particularly where the evaluation of need for additional electrical generation capacity would require a rigorous and robust analysis and would be time-consuming and burdensome for the permit issuer. In such circumstances, the permit issuer is granted considerable latitude in exercising its discretion to determine how best to apply scarce administrative resources.

EPA has noted previously that in general, in California, in order to conduct a reasoned analysis to determine the need for new power plants in general, or a specific power plant in particular, either within the State as a whole, or in a particular geographic location within the State, EPA would need to consider a myriad of extremely complex factors and detailed information that EPA has neither the resources nor the expertise to analyze. This reasoning also applies in this case. The Region has the discretion, but is not required, to conduct an independent analysis of the need for all possible power generated by SPI in the context of this PSD permit proceeding. In this case, EPA does not believe that it is appropriate to conduct the type of rigorous and robust analysis that would be required to definitively determine the need for the Project. Even if EPA did have the expertise and resources to conduct such an analysis, the commenter has not provided any information on which to conduct such an analysis.

A solar component for this Project presents a significant departure from the existing facility's operations and the Project's purpose. In this instance, the existing lumber facility will add equipment within its existing physical footprint and utilize the excess biomass at this and other SPI sawmill or lumber operations.

14. Comment: The fuel mix should be considered in the BACT analysis for the project and the analysis fails to consider a different fuel mix. Increased gas use can raise the temperature and reduce emissions through more complete [combustion].

Response: The Project calls for a new cogeneration unit to be located at an existing lumber manufacturing facility. The cogeneration unit will consist of a biomass-fired boiler, a steam turbine, and a generator. According to SPI's 2010 Application, SPI intends to use biomass from existing SPI facilities, as well as in-forest materials and various sources of agricultural and urban wood waste. Therefore, an inherent aspect of the project is that its fuel use be primarily biomass. The new boiler will also be capable of burning natural gas. The permit limits the amount of natural gas to be combusted to 10% of all heat input into the boiler. EPA believes that this limit is appropriate as the combustion within the boiler may need to be stabilized while burning biomass and to assist with the startup and shutdown of the boiler. While EPA recognizes that fuel mixtures affect the emissions of pollutants, it is unclear what mix the commenter is ultimately recommending and where this should be incorporated into the analysis. If the source changed its fuel mixture then numerous other considerations would need to be made, such as whether a boiler is an appropriate alternative and resulting control technologies. Moreover, alternative fuel mixes would change the profile of pollutants emitted in a myriad of ways where some pollutants would increase and others would decrease depending on the exact mixture.

The commenter references different discussions related to the BACT analysis of GHG emissions where biomass could be considered, but the Project was not subject to the PSD program for GHGs because of the restriction to burn predominantly biomass and only up to 10% of natural gas on a 12-month rolling basis. *See* AAQIR at 9.

15. **Comment:** The commenter states that the BACT analysis fails to adequately consider energy efficiency options. There should be no need for cooling towers and their associated emissions to dissipate heat. The heat should be used in the existing kiln or in a new kiln. The commenter also states that the permit should consider the existing kiln as permitted equipment and that the existing kiln should undergo a BACT analysis.

Response: The BACT analysis in the AAQIR for the Project considers energy efficiency options where appropriate. As outlined in *Section 4- Project Description* of the AAQIR, the fuel combusted in the new cogeneration unit will produce steam that will be used in the existing lumber operations and for feeding a turbine that will drive a generator to produce electricity for use on site or for sale to the electrical grid. Utilization of the existing kilns at the facility does not negate the need for heat dissipation that may result from the combustion of additional biomass for electrical generation.

The AAQIR analyzed contemporaneous emissions changes resulting from the Project. As stated in the application, "the installation of the boiler will not increase emissions from any existing emission units at the Anderson mill. There have been no contemporaneous modifications at the Anderson mill." *See* online docket #I.01: *SPI-Anderson PSD Permit Modification Application_25MAR10* at 3. As a result, the existing kilns are not expected to undergo a change in the method of operation that would result in an increase in emissions of NSR regulated pollutants. Therefore, the existing kilns were not subject to a BACT analysis.

16. **Comment:** The commenter states that the permit should identify the existing equipment and require its retirement, and that the administrative record demonstrates that the permit should require that existing units should not operate concurrently with the new units.

Response: Table 4-2 of the AAQIR identifies existing equipment. *See* AAQIR at 7. As noted by the AAQIR, we did not include this existing equipment in EPA's PSD permit because it is already permitted by SCAQMD. Both permits (SCAQMD's permit and EPA's permit) will be in effect and enforceable.

With regard to the commenter's assertion that existing equipment should be retired, we note that many of the existing emissions units support the existing sawmill operations, and that retirement of these units could essentially result in a shutdown of the mill. Requiring retirement of existing units would be inconsistent with the application submitted to us. We note that SPI's application analyzed emissions from the Project assuming that the existing boiler would continue to operate; in other words, SPI's application did not claim any emission reduction credits from shut down of the existing boiler. Generally, if a company chooses to shut down existing equipment, EPA's PSD regulations will allow the permitting authority to consider emission reductions from the shutdown equipment in projecting emissions increases from the new equipment. If the project's net emissions remain below EPA's PSD major modification thresholds, the project would not be subject to federal PSD requirements for BACT, ambient air quality impacts, etc. SPI's application, however, did not present such a netting analysis, and we have processed it as an application for a major modification requiring a PSD permit. We also note that the commenter did not provide any legal or factual reasons to explain why he believes that EPA should require the retirement of existing units at the facility, and we are not aware of any in SPI's application or elsewhere in the record.

With regard to the commenter's assertion that the permit should require that existing units not operate concurrently with the new units, we understand the commenter to be referring to concurrent operation of the existing boiler and the new boiler. We note that SPI's 2010 application states that "the existing and proposed boiler would not operate concurrently other than some overlap during startup and shutdown." *See* online docket #I.01: *SPI-Anderson PSD Permit Modification Application_25MAR10* at 9. Therefore, the application can be understood as stating that SPI will, at times, operate the boilers concurrently. The commenter did not provide legal or factual reasons that would support a permit condition prohibiting concurrent operation, and we are not aware of any in SPI's application or elsewhere in the record.

17. Comment: The commenter states that EPA has no authority to modify the underlying State permit.

Response: As explained in our public notice, this permit modification is a modification to an existing PSD permit issued by Shasta County AQMD to SPI in 1994. The original PSD permit was issued by Shasta County APCD, pursuant to a delegation of EPA's PSD permitting authority under 40 C.F.R. Part 52 to Shasta County AQMD. In 2003, EPA rescinded the PSD delegations for several California air districts, including Shasta County. 68 FR 19371 (April 21, 2003). We have not re-delegated PSD permitting authority to Shasta County; therefore, EPA is the PSD permitting authority for this action.

18. Comment: The commenter states that the analysis fails to consider the emissions associated with the collection, transport and handling of biomass. Also, the commenter states that a permit condition should require that all associated equipment operates on methane gas or biomass power.

Response: Fuel handling equipment, as stated in the AAQIR, is currently permitted under the existing PSD permit issued by the District. Moreover, mobile tailpipe emissions from the facility are not regulated under the PSD program. The commenter provided no legal or factual basis for his assertion that the permit should include a permit condition requiring that all associated equipment operates on methane gas or biomass power. Such a condition would be technically infeasible. Although the permit limits natural gas heat input on an annual basis, natural gas may be needed during startup, shutdown and for combustion stabilization at multiple times during the facility's operation. Requiring associated equipment to only operate on biomass power or inappropriately limiting the use of natural gas could be detrimental to the equipment used for the facility's normal operation.

19. Comment: The commenter states that the analysis fails to consider increased kiln emissions and other operational emission increases. The commenter also states that the project should be based upon a comparison to the actual baseline instead of prior permit levels.

Response: Table 6-1 of AAQIR summarizes estimated emissions from the Project. Contrary to the commenter's assertion, we did not evaluate the Project using a baseline of prior permit levels. SPI stated that the Project will not increase emissions from any existing units. *See* online docket # I.01: *SPI-Anderson PSD Permit Modification Application_25MAR10* at 4. Moreover, the applicant also stated that emissions increases from fuel handling operations were not projected to increase. *See* online docket #I.05: *SPI-Anderson_response_to_2nd_EPA_incomplete_letter-final_07SEP10*. Therefore, projected actual emissions from existing units at the SPI- Anderson facility were assumed to be equal to baseline actual emissions.

The Project consists of three new emission units and, consistent with EPA's regulations at 40 CFR §52.21(a)(2)(iv)(c), (d) and (f), we evaluated the Project using an actual emissions baseline of zero for the new emission units. *See* online docket # I.01: *SPI-Anderson PSD Permit Modification Application_25MAR10*, at Tables 2-1 and 2-2; #I.41: *SPI-Anderson Annual Emissions MEMO_05SEP12*. Tables 2-1 and 2-2 of SPI's 2010 Application and Table 6-1 of EPA's AAQIR summarize the estimated emissions increases from the Project and our conclusions that the Project would exceed the significance levels for CO, NO_x, PM, PM_{10}, and $PM_{2.5}$. We note that use of the baseline suggested by the commenter would not necessarily lead to additional procedural or substantive requirements for this Project because EPA and SPI analyzed the Project with a baseline of zero – as such, all emissions increases from new equipment were considered in our analysis.

20. Comment: The air quality monitoring station 50 miles away.

Response: As was stated in Section 8.4.3.3 of the AAQIR: "Despite its distance from the project site, the monitor from Chico is conservative based on its proximity to a more industrial area at the north end of the Sacramento Valley." In addition, EPA has looked at the traffic counts near SPI- Anderson and near the Chico monitor and observed that they both have similar traffic counts and major highways nearby, I-5 and Highway 99 respectively. Thus, the Chico monitor is not only representative of the background concentrations in the Project area, but also more conservative given its proximity to a more industrialized area and the similar number of traffic counts.

21. Comment: The commenter states that EPA failed to identify the environmental justice community in the vicinity of the proposed project. It is inadequate for the EPA to skip this and simply claim no harm to any potential community without notification.

Response: Please see the response to comment #9.

22. Comment: The commenter states that the analysis is misleading because it does not disclose that the project intends to burn urban wood or post consumer wood which would be more appropriately burned with a DLN burner.

Response: EPA does not agree that our analysis is misleading. The new boiler will generate electricity from the combustion of biomass and not be permitted to burn waste that is not considered a traditional fuel. See response to the comment #86 for more detail. In particular, *Condition X.G.1.* in the PSD permit restricts fuel to natural gas and the following:

a. Untreated wood pallets, crates, dunnage, untreated manufacturing and construction wood debris from urban areas;
b. All agricultural crops or residues;
c. Wood and wood wastes identified to follow all of the following practices;
   i. Harvested pursuant to an approved timber management plan prepared in accordance with the Z'berg-Nejedly Forest practice Act of 1973 or other locally or nationally approved plan; and
   ii. Harvested for the purpose of forest fire fuel reduction or forest stand improvement.

To the extent the commenter is stating that the new boiler should be equipped with a DLN burner, we note that, as stated in the AAQIR, estimated emissions from a boiler with DLN boilers are higher than the limits we have proposed for SPI's new stoker boiler. *See* AAQIR at 13.

23. **Comment:** The commenter states the permit fails to require appropriate ash bunker waste disposal.

Response: We disagree. This PSD permit is intended to protect public health and welfare from actual or potential adverse effects that may reasonably be anticipated to occur from air pollution or from exposures to pollutants in other media that originate as emissions to the ambient air. The commenter did not specify any appropriate additional waste disposal requirements that he believes should be included in the PSD permit. We note, however, that the proposed and final permits include conditions for the wood waste and ash waste storage and transportation. In particular the following conditions in *Section X.F.* contain storage bin and ash transport requirements:

5. Wood waste collection and storage bin leaks shall be minimized at all times. All indentified wood waste collection and storage bin leaks, spills and upsets of any kind shall be corrected or cleaned immediately, within 4 hours, as practicable, to correct the leak, spill or upset.
6. Wood waste collection and storage bins shall be emptied on a schedule that ensures that the cyclone-separator system does not become plugged.
7. Wood waste collection and storage bins, not including the fuel shed, shall remain enclosed to mitigate the fugitive emissions from the unloading process.
8. All ash shall be transported in a wet condition in covered containers or stored in closed containers at all times.

24. **Comment:** The commenter states, "EMx, SCR and Urea should be required."

Response: The BACT analysis in AAQIR for the Project details why EPA is not requiring installation of an EMx or SCR. The commenter did not provide further legal or factual bases for his comment; therefore, it is unclear why the commenter believes this alternative control technologies should be required.

25. Comment: The commenter states that consideration of the McNeil facility is entirely speculative and that additional analysis is required to distinguish the SPI project from the McNeil facility.

Response: We disagree. Our BACT analysis considered the State of Vermont's permit for the McNeil Generating Station (McNeil), which has a stoker boiler controlled by regenerative selective catalytic reduction (RSCR) technology. The permit for the McNeil facility imposes several NO_x limits, including Condition 11(g), which limits NO_x emissions to 0.075 lb/MMBtu, averaged over a calendar quarter. *See* online docket #I.38: *McNeil Generating Station Title V Permit,* at 15. Condition F(c) of the permit, however, states that Condition 11(g) is enforceable only by state authorities and is not federally enforceable, whereas all other limits in the permit are federally enforceable. *See* online docket #I.38: *McNeil Generating Station Title V Permit,* at 8-9. As stated in our AAQIR for the Project, we do not believe that this limit is the result of a BACT analysis or that it constitutes a BACT determination. *See* AAQIR at 15-16. We also note that, as shown in Table 7.1-1 of our AAQIR, the McNeil NO_x emissions limit of 0.075 lb/MMBtu, is averaged over a calendar quarter, whereas the limit we have proposed for the Project is 0.15 lb/MMBtu, averaged over 3 hours, a much shorter, and therefore more stringent time period. We note further that Condition 11(a) in the McNeil permit imposes a limit of 0.23 lb/MMBtu (no averaging period specified) for NO_x, which is higher than our short-term BACT determination for SPI of 0.15 lb/MMBtu (3-hour average). Thus, our BACT determination for NO_x for SPI is as stringent, if not more stringent, than the McNeil emissions limit for NO_x issued by the State of Vermont. The commenter has not made any demonstration as to why any further analysis needs to be performed or to what end.

26. Comment: The commenter states that the PSD increment trigger date for $PM_{2.5}$ should have been when the original permit was issued

Response: EPA disagrees. As noted in Section 8.4.3. of the AAQIR, the applicable trigger date for $PM_{2.5}$ is October 20, 2011. 40 CFR 52.21(b)(14)(ii)(c). EPA correctly applied the appropriate trigger date and it is unclear why the commenter believes that a different PSD increment trigger date should have been used.

27. Comment: The commenter states that the analysis must demonstrate the nitrogen deposition on the adjacent elderberry plants.

Response: As stated in the AAQIR for the Project, EPA is required to ensure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat. EPA concludes that the project will have no likely adverse effect on any endangered or threatened species or designated critical habitat. Discussions with the United States Fish and Wildlife Service (USFWS) support EPA's conclusion.

The commenter did not provide a legal or factual basis for his assertion that EPA must demonstrate the nitrogen deposition on the elderberry plants. In particular, page 3 of the

July 9, 1999 *Conservation Guidelines for the Valley Elderberry Longhorn Beetle* from the USFWS states that "complete avoidance (i.e., no adverse effects) may be assumed when a 100-foot (or wider) buffer is established and maintained around elderberry plants containing stems measuring 1.0 inch or greater in diameter at ground level." *See* online docket #II.03: *USFWS Conservation Guidelines of Elderberry Longhorn Beetle*. As stated in our AAQIR, SPI has confirmed that construction activities will not occur within 100 feet of the elderberry shrubs that are in the Pacific Gas and Electric power line right of way and that the nearest construction activity to the existing elderberry plants will be the erection of the electrical power poles at the existing electrical sub-station which are 137 feet away from the nearest elderberry shrub. *See* AAQIR at 45.

Comments Submitted by Ms. Gretel Smith of Helping Hand Tools

28. Comment: The commenter requests an extension of the public comment period for the reasons stated in comment #11.

Response: Please see response to comment #11.

29. Comment: The commenter states that the AAQIR fails to show any analysis to support its conclusion that no Environmental Justice issues exist. The AAQIR should contain a complete Environmental Justice evaluation to support the conclusion stated.

Response: Please see response to comment #9.

30. Comment: The commenter states that measurements of background ambient air quality from an air quality monitoring station 55.5 miles from the proposed site should not be used because measurements at or near the actual site must be used to obtain accurate data that represents the actual air quality at the proposed site.

Response: Please see response to comment #20.

31. Comment: The commenter states that the permit fails to calculate the cumulative effect of secondary emissions. The cogeneration plant will receive its fuel from onsite and from offsite facilities via truck. The AQIA fails to analyze the cumulative impact on GHG and other emissions the trucks contribute to the overall emissions of the plant. The secondary environmental impact from transportation of the bio fuel and the removal of waste from the facility should be analyzed. Further, the AQIA does not analyze the cumulative impact of the secondary emissions from the kilns. The AQIA should analyze secondary emissions, BACT on the secondary emissions should be imposed, and the permit should include an emissions limit on the secondary emissions.

Response: The permit modification required BACT on all applicable emission units in the Project. In particular, truck emissions were not considered in a discussion of secondary emissions because secondary emissions do not include any emissions which come directly from a mobile source, such as emissions from the tailpipe of a motor vehicle, from a train, or from a vessel. 40 CFR 52.21(b)(18). As discussed in the response to comment #19, emissions from the kilns were not projected to increase and were not subject to a BACT analysis.

32. **Comment:** The comment claims that the permit should require the technology that achieves the lowest possible emissions rate, including EMx or DLN burners.

Response: Our BACT analysis included evaluations of both EMx and DLN burner systems. AAQIR at 13. EPA concluded that the EMx was technologically infeasible for a biomass boiler. DLN burners, while technologically feasible, would not result in lower emissions of NO_x than what was proposed. The commenter provides no legal basis for its statement that the permit should require the technology that achieves the "lowest possible emissions rate." As stated in section 169(3) of the Clean Air Act, BACT means an emission limitation based on the maximum reduction of each pollutant subject to regulation under the Clean Air Act while taking into account energy, environmental, and economic impacts. 42 U.S.C. §7479(3).

33. **Comment:** The BACT analysis fails to establish the type of ammonia the SNCR or SCR will use. This is important because the transportation and storage of certain types of ammonia poses a public health risk. Additionally, ammonia slips vary from the types of ammonia utilized by the plant.

Response: Ammonia is not a pollutant subject to regulation under the PSD program. *See* 40 CFR 52.21(b)(50). Therefore, our BACT analysis did not include a detailed review of possible ammonia emission reductions. As part of Step 4 of our NO_x BACT analysis, however, our AAQIR identified various types of ammonia that could be used as a reagent in the SNCR system, and explained that compared to anhydrous ammonia, aqueous ammonia and urea require more fuel to evaporate the additional water in those types of reagents. AAQIR at 16. Our analysis also noted that all types of ammonia reagents require energy to inject the reagent into the exhaust and that the exhaust will contain some small quantity of ammonia regardless of what type of reagent is used. Thus, our review of environmental and economic impacts in our BACT analysis for NO_x did not result in a clear indication that one type of reagent should be specified. EPA notes that in addition to the NO_x emissions limitation required by the PSD permit, the source is subject to District Rule 3-26 which limits ammonia emissions to 20 ppm.

SPI's 2010 Application states that SPI intends to use anhydrous ammonia. *See* online docket #I.01: *SPI-Anderson PSD Permit Modification Application_25MAR10* at 3. Although EPA did not evaluate the relative effectiveness of various ammonia reagents in our BACT analysis, SPI observed in discussions with EPA that anhydrous ammonia is more effective at its other biomass and sawmill facilities at reducing NO_x emissions and maintaining compliance with ammonia slip requirements compared to other types of reagent ammonia, such as urea and aqueous ammonia. The applicant also noted that it does not store more than 10,000 lbs of anhydrous ammonia on any of its other sites at one time. *See* online docket #V.03: *Ammonia Discussion with SPI_13NOV12*.

In response to the commenter's concern for public safety related to the storage of certain types of ammonia, we note that the Shasta County Department of Resource Management considered risks associated with the storage of ammonia and ultimately recommended the approval of Use Permit 07-021 for the Project. *See* online docket #V.04: *Report to Shasta County Planning Commission_14JUN12* at 1. The County's report states that SPI would be required to update its existing Hazardous Materials Business Plan/Spill Prevention Control and Countermeasure Plan and an Emergency Response Plan. "These plans shall provide for specific Best Management Practices to be employed during construction and operation … policies and procedures to be implemented in the storage and handling of hazards and hazardous materials and emergencies, and dissemination of information included in the plans to contractors and employees. Implementation of the plans would reduce potential impacts related to hazards and hazardous material and in the event of an emergency to a less-than-significant level." *See* online docket #V.04: *Report to Shasta County Planning Commission_14JUN12* at 5.

The transportation of anhydrous ammonia is regulated under the Federal Motor Carrier Safety Administration (FMCSA) of the U.S. Department of Transportation (DOT). However, in response to the commenter's concern regarding the transportation of anhydrous ammonia, EPA has also considered the risk of an accident resulting from the truck shipments resulting from the Project. The Project is estimated to require 183,960 pounds per year of ammonia. *See* online docket #I.01: *SPI-Anderson PSD Permit Modification Application_25MAR10* at TableA-1 of Appendix A at 41. As noted above, the applicant stated that it does not store more than 10,000 lbs of ammonia, the threshold quantity of ammonia according to 40 CFR 68.130, on site at any one time. Assuming one truck can replenish 10,000 lbs of ammonia, the Project will require approximately 19 shipments of ammonia per year. With several suppliers of anhydrous ammonia within 200 miles of the SPI- Anderson location, EPA estimates that this would result in 8,000 miles of truck miles travelled, including roundtrips. However, tank shipments carrying ammonia would be in only one direction, therefore 4,000 miles of ammonia transport for the Project would result each year. In a report sponsored by the FMCSA, the average hazardous material accident rate was 0.32 estimated per million miles travelled. *See* online docket #V.05: *FMCSA Risks of Hazardous Material Truck Shipment_March 2001* at ES-4. Therefore, 4,000 miles of ammonia transport per year would result in an estimated single truck accident for the Project in 800 years. However, only 28% of all accidents in the FMCSA study were characterized as spill accidents. *See* online docket #V.05: *FMCSA Risks of Hazardous Material Truck Shipment_March 2001* at 10-2 This further reduces the estimated accident frequency related to the ammonia transport from the Project to 1 spill in 3,000 years from a truck carrying 10,000 lbs or less of ammonia to the Project site.

A report prepared by EC/R for another EPA action, states that a national database operated by the National Toxic Substance Incidents Program of the U.S. Agency for Toxic Substances and Disease Registry reports that between 2005 – 2010, there were 45 incidents involving anhydrous ammonia; that all incidents were associated with agricultural use of the chemical; and that the vast majority of those incidents were associated with loading operations or soil applications, rather than transport on highways or public areas. There were no incidents involving anhydrous ammonia use at a power plant or transportation to a power plant between 2005 and 2010. *See* online docket #V.06: *ECR Mobile Source Risk Estimate Report_30JUL12* at 12.

34. Comment: Step 4 of the BACT analysis comparing SCR and SNCR fails to analyze comparative costs of facilities. The analysis should include a comparative cost to other facilities.

Response: The commenter provided no legal or technical basis for consideration of comparative costs to other facilities. We received a similar comment from another commenter that suggested that we should analyze comparative costs. Our response to that comment is at #44, below.

35. Comment: The temporary deferment of requiring BACT on Greenhouse gas emissions (GHG) for biofuels does not apply to plants that use natural gas. (76 FR No. 139, July 20, 2011; 40 CFR 52.21 (b)(49)(ii)(a); 40 CFR 41.166(b)(48)(ii)(a). The EPA does not state what percentage of natural gas will contribute to the GHG emissions of the plant.

Response: The deferral for CO_2 emissions from bioenergy and biogenic sources under the PSD program was applied to those CO_2 emissions that result from the combustion of biomass. *Condition X.G.2.* of the final permit limits natural gas usage to 10% of the annual heat input to U1. We included CO_2 emissions from natural gas in our analysis of whether the Project was subject to BACT for GHG. *See* AAQIR at 49-50. However, the GHG emissions from natural gas, as measured in CO_2e, were below the subject to regulation threshold and the Project was not subject to BACT for GHG. *See* AAQIR at 9.

36. Comment: EPA should consider the kilns in the analysis of emissions and operations process of this plant. There should be an analysis of the effects of not using a cooling tower.

Response: Please see the response to comment #15.

37. Comment: The BACT analysis does not analyze the use of a solar component to offset some or all of the emissions resulting from the use of natural gas.

Response: Please see the response to comment #13.

38. Comment: The commenter states that the AAQIR does not fully analyze the nitrogen deposition impact of the surrounding area. The commenter states that the AAQIR should analyze the nitrogen deposition impacts and the effect the emissions impacts may have on the surrounding flora and fauna including the elderberry shrubs in the immediate vicinity of the plant.

Response: Please see the response to comment #27.

Comments Submitted by Mr. Kevin Bundy of the Center for Biological Diversity (CBD)

Technical Feasibility of Fluidized-bed Boiler Designs

39. **Comment:** The commenter disagrees with EPA's statement in the AAQIR that SPI has not entered a binding power purchase agreement (PPA) with consistent base load electricity demand. The commenter states that although final state regulatory approval is still pending, SPI has entered into a power purchase agreement with Pacific Gas & Electric Company (PG&E).

Response: The commenter's submittal includes an "Attachment A," which is an "Advice Letter," dated September 7, 2012, and submitted by PG&E to the California Public Utilities Commission (CPUC). PG&E's Advice Letter describes a purchase power agreement (PPA) between PG&E and SPI and identifies a PPA as Appendix F. (The commenter did not submit Appendix F to the Advice Letter, apparently because the PPA itself is confidential). Based on the Advice Letter, EPA acknowledges that a PPA between PG&E and SPI does in fact appear to exist. We appreciate the commenter's bringing this information to our attention. We note that the public comment period for this permit began on September 12, 2012, just three business days after the date of the Advice Letter. We also note that the Advice Letter indicates that the PPA is not yet final because it appears to be currently pending before the California Public Utilities Commission (CPUC) and PG&E has requested the CPUC's approval of the PPA by March 2013. Finally, we note that the Advice Letter is signed by PG&E, not SPI; therefore, it is problematic to ascribe significance to it without qualification.

40. **Comment:** The commenter states that to the extent there is a feasibility problem, it results from contractual terms that SPI negotiated, as opposed to technical limitations. The commenter argues that the Advice Letter states that PG&E's obligation to purchase power from SPI is limited to the amounts specified under current contracts, which will expire in 2016 and 2017. The commenter continues that SPI intends to commence operation of the new boiler in 2014 and ramp up to full power production in 2017. The commenter concludes that the operational flexibility SPI seeks will be necessary for only three years and only because of contractual terms that SPI negotiated. The commenter states that even if SPI has negotiated a PPA that restricts it from selling the facility's full output for the first three years of operation, that business decision does not make fluidized-bed boiler alternatives technologically infeasible under Step 2 of the BACT analysis and that this business decision should not be the basis of a permit that would allow SPI to install and operate equipment that will emit higher rates of pollutants for decades after 2017.

Response: SPI submitted to EPA a letter dated January 23, 2012 explaining its need for a stoker boiler, as opposed to a fluidized bed boiler. In short, SPI's letter states that the new boiler will be used for two purposes: (i) to produce steam to operate lumber-drying kilns for SPI's saw mill operation; and (ii) to produce steam to power a turbine and electrical generator that will produce electricity for sale to the power grid. SPI's letter states that the new boiler must be able to operate at loads between 20 percent and 100 percent because the boiler must continue to provide steam for its saw mill operation even if demand for grid power was not present and the steam turbine and generator are taken offline. SPI's letter explains that it anticipates that there may be low demand for grid power in the near term, which will require it to operate the new boiler at low loads because PG&E, the purchaser of the power to be generated by the new boiler / turbine / generator, has projected that "between 2014 and 2017, and perhaps beyond," it will have more renewable energy available to it than it will need to meet California renewable energy standard requirements.

SPI's January 2012 letter also refers to operations at its facility in Lincoln, California, which includes a stoker boiler, lumber-drying kilns, and a steam turbine and generator. SPI's letter explains that the Lincoln facility's stoker boiler has been capable of operating at low load and maintaining operation of the lumber drying kilns when the steam turbine and generator were offline for unscheduled repairs. SPI's letter thus describes another scenario in which a boiler capable of operating at low load is able to accomplish its business purposes.

In addition, SPI's January 2012 letter states that a boiler that cannot operate at lower loads would have to be shut down, which would result in shutdown of the saw mill's lumber-drying kilns and possibly a complete shutdown of the mill. According to SPI's letter, which included a supporting reference to a fluidized bed boiler manufacturer, fluidized bed boilers are unable to operate at lower load rates (i.e., a turndown mode). SPI stated that a fluidized bed boiler was therefore incompatible with its planned use of the new boiler to produce process steam as well as steam to generate electricity for sale to the power grid.

Based on SPI's January 2012 letter, as well as SPI's other submittals, SPI's business purpose in constructing the new boiler is two-fold: to process steam for its mill operations and to provide a renewable energy source of grid power. To meet these dual purposes, SPI requires a boiler type that can operate under varying loads: at low load when steam is required only for mill operations; and at high load when steam is required for both mill operations and grid power. SPI has provided technical support for a determination that a fluidized bed boiler is not capable of meeting both purposes, and the commenter did not provide technical evidence to the contrary. Moreover, it is of little relevance that SPI may have negotiated a contract for the sale of electricity that does not require full steam production at all times – BACT does not require that the permit applicant enter into business contracts that will maximize the use of permitted emissions units. SPI's business purpose for selection of a stoker boiler is that is fulfills two purposes and SPI has provided a technical justification that a fluidized bed boiler cannot adequately fulfill both purposes.

41. **Comment:** The commenter states that it is not clear that the operational flexibility SPI seeks is necessary at all. According to the commenter, deliveries in excess of PG&E's renewable energy obligations will be bankable; therefore, it appears unlikely that PG&E would require SPI simply not to generate excess power that PG&E could easily bank in order to meet an acknowledged future compliance deficit.

Response: The comment questions SPI's justification for operating in a turndown mode, and thus SPI's need for a stoker boiler. We note that although the Advice Letter states that excess power would be bankable and available for future compliance periods, it does not "acknowledge" a future compliance deficit. Advice Letter at 17-18. In addition, the motivations of PG&E, which is not the permit applicant, are outside the scope of our authority to consider when reviewing a PSD permit application. Furthermore, the comment does not address SPI's stated need for a boiler that can operate in turndown mode as a result of maintenance or repair on the steam turbine and generator.

42. Comment: The commenter states that EPA must consider alternatives to the facility as proposed. For example, EPA could deny the permit outright and allow the applicant to renew the application once the need for the facility arises. Another alternative would be to prohibit operation of the new boiler and allow SPI to continue to operate the existing boiler for power and process steam until 2017 or whenever the PPA requires full base load power deliveries. These alternatives are consistent with the PPA, SPI's submittals, and EPA's statement of basis and demonstrate that fluidized-bed boiler designs should not have been rejected as technically infeasible.

Response: EPA, the permit issuer for the Project, does not have an obligation to independently investigate all possible alternatives. The Environmental Appeals Board has observed the importance of this limitation on the permit issuer's obligation, particularly where the evaluation of need for additional electrical generation capacity would require a rigorous and robust analysis and would be time-consuming and burdensome for the permit issuer. In such circumstances, the permit issuer is granted considerable latitude in exercising its discretion to determine how best to apply scarce administrative resources. EPA has evaluated the Project for all of the of the appropriate applicable PSD requirements. Moreover, we note that the comment does not address SPI's stated need for a boiler that can operate in turndown mode in the event of maintenance or repair on the steam turbine and generator.

EPA's Rejection of Catalytic Control Technologies as BACT for NOx

43. Comment: The commenter stated that EPA's BACT analysis is inconsistent because it concludes that SCR is technically feasible but rejects SCR on the lack of demonstrated effectiveness. SCR should have been ranked as the top control option at Step 3.

Response: Step 3 of our BACT analysis ranked SCR as the top control option. *See* AAQIR at 15, Table 7.1-2. The fact that there is little operational data for SCR on stoker boilers is a factor that we considered in Step 4, as part of our analysis of economic impacts. Please see our response to comment #44 below. After a thorough review, EPA determined that BACT for NO_x for the Project is 0.13 lb/MMBtu on a 12-month rolling basis and 0.15 lb/MMBtu on a 3-hour block average.

44. Comment: Citing the Draft NSR Manual at B.31-B.32, the commenter states that the BACT analysis fails to consider the cost effectiveness of the proposed control relative to other similar sources that have employed that control. The commenter states that neither the Statement of Basis nor SPI's application contains comparative information about average and incremental costs of SCR at other biomass facilities that have employed SCR or RSCR as BACT. Evaluation of economic impact on the proposed facility alone is insufficient to support rejection of a proposed control measure as BACT.

Response: The portion of the Draft NSR Manual cited by the commenter recommends that an applicant document significant cost differences between control technologies "where a control technology has been *successfully applied to similar sources in a source category*. . ." Draft NSR Manual at B.31 (emphasis added). We were unable to find significant support for a finding that either SCR or RSCR has been successfully applied to biomass stoker boilers, nor did the commenter provide any such examples. As shown in our AAQIR at Table 7.1-1, our BACT analysis included information regarding a number of recent BACT determinations for stoker boilers. Table 7.1-1 shows that, although seven facilities have received permits that would require use of SCR or RSCR, five of those facilities have not been constructed; thus, those five BACT determinations do not represent an "achieved in practice" standard. Our review found only one source, Lufkin Generating Plant (Lufkin), constructed with SCR. Since completing construction in late 2011, Lufkin has operated sporadically; as a result, the facility has not generated a significant quantity of emissions data, making it difficult to verify that the NO_x emission rate of 0.075 lb/MMBtu on a 30-day rolling basis has been achieved in practice. In addition, our review found only one source constructed with RSCR, McNeil Generating Station (McNeil). The limit identified in Table 7.1-1 for this source, 0.075 lb/MMBtu, is averaged over 150 days and has been verified; however, the short-term limit for the McNeil boiler is 0.23 lb/MMBtu (no averaging period specified), which is higher than our short-term BACT determination for SPI of 0.15 lb/MMBtu (3-hour average).

In making our BACT determination for SPI, we considered the lack of operational data for SCR for similar sources as well as the $9,000 per ton of NO_x removed incremental cost for SCR (compared to SNCR) at SPI. Our determination is consistent with the Draft NSR Manual, which recommends documentation of significant cost differences between control technologies when the permitting authority is eliminating a control technology that has been successfully applied to similar sources. In this case, we were unable to find that SCR has been successfully applied to similar sources, and in the limited instance of RSCR at McNeil, we found that our BACT determination for SPI was at least as stringent, if not more stringent, than the limit for McNeil.

45. **Comment**: The commenter states that EPA did not clearly explain why it selected SPI's proposed NO_x emission limits as BACT. Other facilities with SNCR have been permitted at lower emission rates and "demonstrated in practice" should not be the controlling factor. The commenter also argued that if EPA is adopting an emission limit with a margin of safety, then EPA must explain its choice and support it in the record.

Response: Our AAQIR did not reference "compliance margin" as a basis for our BACT determination; the commenter is apparently assuming that we were relying on this concept as a basis for our NO_x BACT determination. Our AAQIR, however, explained that the basis for our determination is that the limit is the most stringent NO_x emissions limit for stoker boilers with SNCR demonstrated in practice and that the incremental costs of SCR above the costs of SNCR made SCR cost prohibitive. *See* AAQIR at 15-16.

Our NO_x BACT determination was based in part on the information provided in Table 7.1-1 of the AAQIR, which lists recent NO_x BACT determinations for biomass stoker boilers.

Two determinations include the use of SNCR and lower NO_x emissions limits than the limit proposed for SPI; however, neither facility has been constructed, and, therefore, those limits have not been demonstrated in practice. In addition, we note that Table 7.1-1 of the AAQIR shows that the lower NO_x limits using SNCR are subject to longer averaging periods (0.1 lb/MMBtu (30-day rolling average) and 0.12 lb/MMBtu (24-hour block)) than the short term limit we have proposed for SPI (0.15 lb/MMBtu (3-hour block)).

In addition, SPI presented information that although another of its facilities received a NO_x limit of 0.1 lb/MMBtu, SPI was unable to achieve this lower limit without using excessive amounts of ammonia. Specifically, SPI's 2010 application states that SPI received a permit in 2006 for a 450 MMBtu/hr boiler at its facility near Burlington, Washington with NO_x limits of 0.13 lb/MMBtu (24-hour average) and 0.1 lb/MMBtu (12-month rolling average). SPI stated that the 0.1 lb/MMBtu (12 month rolling average) limit was removed from the permit because excessive ammonia use in the SNCR system resulted in a secondary plume. *See* online Docket #1.01: *SPI-Anderson PSD Permit Modification Application 25 MAR10*, App. B at 7, n.3. We also note that SPI's Anderson facility is subject to District Rule 3-26, which limits ammonia slip emissions which can result from excessive ammonia use.

EPA's BACT determination for CO

46. Comment: The commenter states that the BACT analysis for CO contains the same flaws as the BACT analysis for NO_x. According to the commenter, these flaws are the rejection of fluidized-bed boiler design alternatives as technically infeasible and the failure to compare average and incremental cost of catalytic CO controls with equivalent costs at other comparable facilities.

Response: Because the commenter is not raising new concerns with respect to our BACT analysis for CO separate and apart from the issues the commenter raised regarding our BACT analysis for NO_x, our response to this comment is largely by reference to the responses regarding the NO_x BACT comments. In addition, we have a few other points to make that are specific to our CO BACT analysis.

With regard to the BACT determination for CO and the corresponding installation of add-on control technology alternatives to the stoker boiler, EPA believes its BACT determination was appropriate. Of those facilities identified in the BACT analysis with lower permitted CO emissions limitations, three other permitted sources in Table 7.1-3 have lower CO emissions limitations through the implementation of an oxidation catalyst and three employ good combustion. None of the six facilities identified has constructed. The AAQIR for the Project describes an oxidation catalyst as a technically feasible control alternative and provides context that verifiable data with biomass stoker boilers implementing an oxidation catalyst remains limited. In its review of add-on control alternatives, EPA not only considered the cost of an oxidation catalyst, but also what has been achieved in practice with stoker biomass boilers. EPA also reviewed a number of facilities and permit determinations that were not provided by the applicant in its BACT analysis materials.

Some proposed facilities have lower permitted emission limits for CO through the implementation of good combustion and others have higher permitted emission limits. However, as noted in SPI's application, "emissions resulting from incomplete combustion (CO and VOC) are balanced with emissions related to high furnace temperatures (NO_x) to achieve optimally low emissions of all pollutants. However, in order to achieve the proposed NO_x emission limit (0.13 lb/MMBtu) while not exceeding 20 parts per million (ppm) ammonia slip, as required by Shasta County (Shasta County AQMD Rule 3:26.c.4), boiler operation will favor reduced NO_x creation over reduced CO creation." *See* online docket I.01: *SPI-Anderson PSD Permit Modification Application 25MAR10*, App.B at 16. As a result of all these considerations, EPA determined that BACT for CO for the Project is 0.23 lb/MMBtu (3 hour block average) and 108 lb/hour (3-hour block average).

EPA's BACT determination for PM, PM_{10} and $PM_{2.5}$

47. Comment: The commenter states that the BACT analysis improperly concludes the emission limitations for particulate matter. Lower emission limits have been permitted at other facilities, both with the ESP and multiclone technology proposed by SPI and with the baghouse technology which was not selected. EPA does not explain why it chose only a "demonstrated in practice" emissions limit rather than the most effective technically feasible control.

Response: As detailed in the BACT analysis for PM in the AAQIR, EPA identified three biomass stoker boilers with lower permitted emissions limits for PM, none of which has constructed. *See* AAQIR at 19-22, and Table 7.1-5. One of those projects appears to have been canceled, and as noted in our AAQIR, was permitted for filterable particulate only, whereas the SPI limit is for total PM. Beaver Wood Power Biomass Technical Support Document, February 10, 2012, p. 22. The other two proposed facilities listed in Table 7.1-5 have slightly lower emission rates of PM, utilizing different add-on control technologies: Warren County Biomass is permitted with an emission limit of 0.018 lb/MMBtu employing a baghouse, and Beaver Wood Energy is permitted with an emission limit 0.019 lb/MMBtu employing an ESP. Our BACT determination for SPI- Anderson is 0.02 lb/MMBtu.

Our AAQIR for the Project describes both a baghouse and ESP as technically feasible control alternatives. At Steps 1 and 4, we noted that baghouses may present a fire concern and generally require more energy than ESPs. Moreover, our AAQIR explains that SPI estimated the same level of control from both add-on control alternatives at 0.02 lb/MMBtu for PM. *See* AAQIR at 21 and online docket #I.01: *SPI-Anderson PSD Permit Modification Application 25 MAR10*, App. B at 21. We also reviewed a number of facilities and permit determinations that were not provided by the applicant in its BACT analysis materials and what has been achieved in practice. In our review of add-on control alternatives, we considered not only energy and environmental impacts associated with the add-on control alternatives, but also what controls have been achieved in practice with biomass stoker boilers. As a result, EPA has determined that BACT for total particulate matter for the Project is 0.02 lb/MMBtu.

EPA's BACT determination for Emergency Engine Emissions

48. **Comment**: EPA improperly rejected the most stringent emissions control option of NSPS-compliant non-emergency engine for use as an emergency engine without identifying average or incremental cost of controls, providing comparative cost information from other facilities, or reviewing other BACT determinations. EPA's statement that "economic impacts and limited environmental benefit" would not justify use of a more stringent control technology is inadequate.

Response: We received comments from SPI during the public comment period clarifying its intention to install a spark ignition natural gas fired engine rather than a compression ignition engine as stated in the AAQIR. This revision does not affect the lb/hour emissions limits of 0.78 lb/hr NO_x, 6.11 lb/hr of CO, and 0.0216 lb/hr of PM/PM_{10}. In addition, the emergency engine will also be required to comply with the NSPS emergency engine emissions limits provided in 40 CFR 60 Subpart JJJJ, which applies to spark-ignition engines. As stated in the AAQIR, operation of the emergency engine will be restricted to no more than 100 hours per year

We have revised the Emergency Engine BACT Analysis for a spark ignition emergency engine rather than a compression ignition emergency engine. As for the original BACT analysis for the compression ignition engine, we note that the proposed emissions and operational limits will result in extremely low mass emissions on an annual basis. Moreover, we also note that the commenter did not supply additional information that more stringent limits could be consistently achieved in practice for the 191kW engine.

We have concluded that an NSPS-compliant spark ignition emergency engine that is subject to the proposed hourly emission limits and an operational restriction of 100 hours per year represents an adequate balance of the impacts associated with the Project's emergency recirculating pump requirements. In the final permit the spark ignition emergency engine will result in low emissions of approximately 226 lbs/year of CO, 78 lbs/year of NO_x and 3 lbs/year of PM. As such, the spark ignition natural gas emergency engine for the Project is appropriate and meets BACT. For further information, please see our revised Emergency Engine BACT Analysis in the Appendix to this document.

EPA's BACT determination for Cooling Tower Emissions

49. **Comment:** The commenter stated that the BACT analysis does not properly evaluate particulate control for cooling towers. According to the commenter, EPA relies solely on a conclusory and internally contradictory statement to make its final determination and the AAQIR does not identify anything that provides authority for what amounts to an ad hoc *de minimis* exemption from rigorous application of BACT requirements.

Response: We disagree with the commenter that our analysis of cooling tower controls was conclusory or de minimis. As set forth in the AAQIR, we conducted a top-down BACT analysis that considered three types of cooling towers technologies: dry cooling, wet-dry hybrid, and wet cooling with 0.0005% drift eliminators. EPA did not find any saw mill facilities or biomass boilers that use dry cooling or wet-dry hybrid cooling as an alternative to wet cooling. We note that the commenter did not provide any examples of dry or wet-dry cooling tower applications for saw mills or biomass boilers (or any examples at all). Of wet cooling tower options, the applicant's proposal to use DRU-1.5 high-efficiency mist eliminators represents the lowest proposed amount of drift that EPA found in its review of similar facilities. As we noted in the AAQIR, the difference between the various cooling tower control options is approximately 1.10 tons of total PM per year.

In response to the commenter's reference to an internal contradiction in our statement that a reduction in overall efficiency would result from the use of a dry or hybrid wet-dry systems, we acknowledge that we inadvertently included a mis-statement. We should have stated that this efficiency reduction would result from the additional energy requirements for *dry* (not *wet*, as stated in the AAQIR) and hybrid systems. Although we believe that our intent could be discerned from the overall context of our analysis, we appreciate the commenter bringing this mis-statement to our attention.

Without any supporting information available to us, either from our own review or from the commenter, it is difficult to consider an additional sufficient basis on which to establish BACT limits that could be consistently achieved in practice by the Project for the cooling tower. We find that the applicant's proposed control of wet cooling with high efficiency mist eliminators adequately balances the collateral impacts associated with the Project's cooling requirements and has resulted in low potential emissions from the cooling system – 1.1 tons per year of $PM/PM_{10}/PM_{2.5}$. As such, the proposed cooling system for the Project is appropriate, consistent with other PSD permits for similar sources as stated in SPI's 2010 application. *See* online docket #1.01, *SPI-Anderson PSD Permit Modification Application 25 MAR10*, App. B at 29 and meets BACT.

EPA's Air Quality Analysis

50. Comment: The commenter argues that EPA's air quality analysis was deficient because it did not adequately explain why it assumes startup/shutdown NO_x emission rates (when the SNCR system will not be working) are the same as normal operational emission rates. The analysis should explain why NO_x emissions with and without SNCR would be the same. The commenter also stated that there is a discrepancy between the descriptions of the startup process in the AAQIR and a letter submitted by SPI to EPA dated May 30, 2012.

Response: EPA requested that SPI provide a modeling analysis that reflects worst-case conditions during startup. *See* online docket #I.33: *SPI- Anderson to EPA email re SUSD emissions clarification 27JUN12*and # I.11: *SPI-Anderson_updated_modeling_and_SUSD_analysis-final_30MAY12* at Table 5. To the extent that the commenter is questioning why "NO_x emissions with and without the SNCR system would be exactly the same," we emphasize the distinction between, on the one hand, a worst case assumption that NO_x emissions during startup are equivalent to NO_x emissions during normal operations and, on the other hand, a conclusion that such emissions are equivalent. Equivalency between the two scenarios, startup and normal operations, is an assumption being made for modeling purposes in order to capture worst case conditions. To the extent the commenter is questioning the validity of this assumption, we believe the assumption is valid because startup includes firing natural gas, which results in lower NO_x emissions than biomass. In addition, startup involves lower flow rates and reduced exhaust temperatures. Therefore, as a general matter, it is reasonable to assume that emissions during the firing of natural gas will be less than emissions during firing of biomass.

In addition, the applicant supplied comments during the public comment period regarding emissions during periods of startup and shutdown. In its comments, the applicant reiterated that the appropriate mass emission limits were included in the AAQIR and permit; however, the applicant requested that the averaging period for emissions limits for NO_x and CO during startup and shutdown be increased from an hourly average to an 8-hour average. See response to comment #70 in this document. EPA has granted this request and revised the permitted averaging times for NO_x and CO emissions during periods of startup and shutdown.

We also note that the modeling that used this assumption showed that emissions for annual and 1-hour NO_2 and 24-hour $PM_{2.5}$ would exceed SILs; therefore a cumulative impacts analysis was required and conducted. In other words, because SPI had to do the cumulative impacts modeling anyway, the assumption that NO_x during startup was equivalent to NO_x during normal operations did not result in less analysis.

51. **Comment**: The air quality analysis does not quantify secondary $PM_{2.5}$ formation despite high emissions of NO_x, a $PM_{2.5}$ precursor, and does not support its assertion that emissions of secondary $PM_{2.5}$ will be less than direct, primary emissions.

Response: We maintain that our discussion of secondary impacts in Section 8.4.3.2 of the AAQIR is sufficient for characterizing the potential impacts on secondary $PM_{2.5}$ resulting from 270 tpy of NO_x. In addition, most of these chemical transformations in the atmosphere occur slowly (over hours or even days, depending on atmospheric conditions and other variables), causing secondary $PM_{2.5}$ impacts to occur generally at some distance from the source of its gaseous emissions precursors, and are unlikely to overlap with nearby maximum primary $PM_{2.5}$ impacts in space or time.

EPA's Additional Impacts Analysis

52. **Comment:** EPA's additional impact analysis is inadequate because EPA cannot rely on the fact that air modeling shows no violation of the secondary NAAQS as a proxy for analysis of depositional effects on soil and vegetation.

Response: While the commenter noted concerns about characterizing depositional effects based on a comparison to the secondary NAAQS, our determination that the Project would not generally result in adverse impacts to soils or vegetation was based on several considerations as noted in the AAQIR, including air quality related values (AQRVs), soils survey, biological review, and screening procedures guidance. In addition, the AAQIR also outlines our approach for comparing the Project's modeled impacts to EPA's screening concentrations. *See* AAQIR at 41-42. Based on our consideration of the various sources of information, we determined that emissions associated with the project will not result in adverse impacts to soils or vegetation. The following further clarifies our consideration of the AQRVs, soils survey information, and biological review.

SPI's 2007 PSD application included a summary of the results associated with the AQRVs; this summary used CALPUFF to evaluate impacts to AQRVs in Class I areas. Class I Area deposition fluxes for nitrogen and sulfur deposition were calculated from CALPUFF results. Although there are no specific standards for incremental impacts to soils and vegetation, the National Park Service (NPS) has set deposition analysis thresholds (DATs) of 0.005 kg/ha/yr for nitrogen deposition and for sulfur deposition. *See* online docket #V.01: *Guidance on Nitrogen and Sulfur Deposition Analysis Thresholds* at 4. A DAT is the additional amount of nitrogen or sulfur deposition within a Class I area below which estimated impacts from a project are considered insignificant. Nine Class I areas were evaluated, ranging from distances of 57 km to 192 km; the maximum nitrogen and sulfur deposition flux results were 0.0007 and 0.0002, respectively, and therefore not greater than the DATs of 0.005. As a result, the predicted nitrogen and sulfur deposition fluxes containing primary and secondary aerosols attributable to the Project are not expected to significantly impact soils and vegetation within Class I areas.

The DATs, also referenced as concern thresholds, are intended to serve as a quantitative, conservative screening criteria for Federal Land Managers (FLMs) to identify whether there are potential deposition fluxes requiring further consideration on a case-by-case basis. Since the year 2000, the FLMs have provided guidance regarding the AQRVs, which includes discussions regarding deposition. As stated in the most recent FLMs' guidance on nitrogen and sulfur deposition analyses, the information and procedures are generally applicable to both Class I and Class II areas for evaluating the effect of nitrogen or sulfur increases. *See* online docket #V02: *FLM Interagency Guidance for Nitrogen and Sulfur Deposition Analyses_November 2011* at 2.

In subsequent updates and clarifications to SPI's 2010 PSD application, the applicant provided further characterization for soil and vegetation impacts, including soils survey information and a biological review. *See* online docket #I.03: *SPI-Anderson_response_to_EPA_incomplete_letter-final_01JUL10*, #II.01: *SPI-Anderson to EPA re Biological Assessment 01APR10* and #II.02: *Biol Rpt for EPA review_Complete pkg-R 15APR10.* As part of its biological review, SPI did not identify any refuges or preserves containing sensitive soils or vegetation that could potentially be impacted by the proposed project. Section 9.2 of the AAQIR evaluates potential visibility impacts on two Class II areas, the Sacramento River National Wildlife Refuge (38.8 km) and Whiskeytown National Recreation Area (18.3 km). *See* AAQIR at 43-44. SPI's DAT analysis concluded that the Project would result in relatively low deposition fluxes on nearby Class I areas, which we considered as an indicator that adverse impacts on nearby soils or vegetation in these two Class II areas would be unlikely.

With regards to the nearby soils, we considered the soils survey review SPI conducted using the Web Soil Survey (WSS). *See* AAQIR at 41.The WSS is a web-based tool that provides soil maps, data and information produced by the National Cooperative Soil Survey operated by the USDA Natural Resources Conservation Services (NRCS) Based on the applicant's review, we considered the Project's potential nitrogen and sulfur deposition unlikely to further influence the pH of soils (5.3 to 6.5) in the area. Based on discussions with and/or review of information from the USFWS, BLM, and NRCS, we considered this information in determining that the Project's impact would not result in adverse impacts to soils or vegetation.

Finally, we note that the commenter did not suggest any specific additional analysis that we could have or should have conducted. Moreover, we note that, as presented in Table 9.1-2 of the AAQIR, the maximum modeled concentrations of NO_x and SO_x are several orders of magnitude below EPA's secondary NAAQS standards. For all the reasons stated above, we believe our determination that the Project will not generally result in adverse impacts to soils or vegetation was appropriate.

Other Applicable Legal Requirements

53. Comment: The Clean Air Act and EPA's implementing regulations clearly require that SPI demonstrate compliance with other applicable standards, including SIP provisions, NSPS and NESHAP, in conjunction with its PSD application. *See* 42 U.S.C. §7475(c)(3); 40 C.F.R. §52.21(j)(1), but SPI's application and EPA's statement of basis do not discuss compliance with these provisions.

Response: EPA has determined that the emissions limits in the proposed permit are more stringent than, and therefore will assure compliance with, applicable SIP and NSPS requirements. We note that Shasta County has maintained its designations as attainment for all criteria pollutants for many years; therefore, consistent with the Act, Shasta County's SIP does not contain the more stringent emission standards that are typically found in SIPs applicable to nonattainment areas. We have also determined that the Project is subject to the standards of performance of NSPS Subpart Db, and that the proposed permit will assure compliance with those obligations. NSPS Subpart Db states that an affected facility that commences construction after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 250 MMBtu/hr shall not cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 0.030 lb/MMBtu heat input. 40 CFR Part 60.43b(h)(1). The PM emissions limit for the boiler in the Project is 0.02 MMBtu/hr. These requirements were discussed in SPI's 2007 and 2010 applications.

On December 20, 2012, the EPA Administrator signed the final National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT) which will be effective 60 days from the date of publication in the Federal Register. The emission limits for CO and PM in the Boiler MACT for a new biomass stoker boiler are 390 ppm (~0.345 lb/MMBtu) with CEMS and 0.030 lb/MMBtu respectively. The BACT limits for the Project at 0.23 lb/MMBtu for CO and 0.02 lb/MMBtu for PM are more stringent than those in the Boiler MACT. The Project will also be subject to other requirements from the Boiler MACT, such as other non criteria pollutant emission limits, monitoring, recordkeeping and reporting requirements.

54. **Comment:** EPA has not adequately explained why or how it is processing this permit as a major modification. The statement of basis contains no discussion of any contemporaneous emissions changes resulting from the modification or baselines used to evaluate emission increases. The draft permit and statement of basis focus only on the new boiler as if it were the only emissions source at the facility, which makes it impossible to determine how EPA arrived at significance determinations.

    Response: SPI's 2007 and 2010 applications state that the Project will not increase emissions from any existing units. *See* online docket #I.13: *SPI-Anderson PSD 2007 Permit Modification Application* at 7, #I.01: *SPI-Anderson PSD Permit Modification Application_25MAR10*, at 4. SPI also stated that emissions increases from fuel handling operations are not projected to increase. *See* online docket #I.05*: SPI-Anderson_response_to 2nd_EPA_incomplete_letter-final_07SEP10*. In addition, SPI and EPA evaluated the Project using an actual emissions baseline of zero for all new equipment. *See* online docket # I.01: *SPI-Anderson PSD Permit Modification Application_25MAR10* at Tables 2-1 and 2-2, #I.41: *SPI-Anderson Annual Emissions MEMO_05SEP12*. Tables 2-1 and 2-2 of SPI's 2010 Application and Table 6-1 of EPA's AAQIR summarize the estimated emissions increases from the Project and our conclusions that the Project would exceed the significance levels for CO, NO_x, PM, PM_{10}, and $PM_{2.5}$.

    In addition, we disagree with the commenter's suggestion that the draft permit and statement of basis place an inappropriate emphasis on the new boiler. The "Project Description" section of both the draft permit and the AAQIR contain the following statement: "The site currently contains a wood-fired boiler cogeneration unit with associated air pollution control equipment and conveyance systems that produce steam to dry lumber in existing kilns." Draft Permit, at 1; AAQIR at 3. The AAQIR also includes separate tables for new and existing equipment: Table 4-1, Proposed New Equipment List, and Table 4-2, Existing Equipment List. EPA clearly described the Project as a modification of the Facility's existing configuration.

EPA's Deferral of PSD for Biogenic CO_2 and Grandfathering PM

55. **Comment**: The commenter states that EPA's deferral of PSD requirements for biogenic CO_2 emissions is unlawful and that EPA's treatment of biogenic CO_2 emissions in the draft permit would violate the Clean Air Act if EPA's deferral is vacated. The commenter also states that 42 U.S.C. §7465(a)(2) imposes an independent obligation to consider less-polluting alternatives; therefore, EPA must evaluate alternatives that reduce dangerous carbon pollution. The commenter cites several scientific studies to support its argument that combustion of biomass fuels, including green wood and forest thinnings as well as harvest residuals and other wastes, can increase greenhouse pollution for many years.

    Response: As noted by the commenter, there is pending litigation in the D.C. Circuit Court of Appeals regarding our rule, *Deferral for CO_2 Emissions from Bioenergy and Other Biogenic Sources under the Prevention of Significant Deterioration and Title V Programs*, 76 Fed. Reg. 43490 (July 20, 2011). EPA's position is that the Deferral is a proper exercise of our authority under the Clean Air Act in light of the need for further scientific review of CO_2 emissions from biogenic sources. Consistent with our rule and the Agency's position, our PSD analysis for the Project does not include an evaluation for CO_2 emissions.

With regard to alternatives to the Project, we do not agree that our obligations under section 165(a)(2) are as broad as the commenter suggests. EPA does not have an obligation to independently investigate all possible power generation alternatives. Further, the Environmental Appeals Board has observed the importance of this limitation on the permit issuer's obligation, particularly where the evaluation of need for additional electrical generation capacity would require a rigorous and robust analysis and would be time-consuming and burdensome for the permit issuer. In such circumstances, the permit issuer is granted considerable latitude in exercising its discretion to determine how best to apply scarce administrative resources. *In re Prairie State Generating Company*, 13 E.A.D. 1, 32 (EAB 2006) at 33.

In this case, EPA does not believe that it is appropriate to conduct the type of analysis that would be required to "fully evaluate possible permit conditions that would reduce of avoid greenhouse gas pollution" from the Project. Even if EPA did have the expertise and resources to conduct such an analysis, the commenter has not provided any criteria on which such an analysis could be measured against so as to meet the commenter's demand for a "full" evaluation.

56. Comment: The commenter states that the grandfathering provisions in EPA's proposed rule revising the PM NAAQS are unlawful.

Response: As stated in the public notice for the Project, EPA has requested public comment on its proposed action relating to the Project. The commenter states that the Center for Biological Diversity has submitted comments to EPA with regard to the specific issue of grandfathering PSD actions in the context of our recently proposed PM NAAQS. EPA will address those comments as part of our rulemaking action on the PM NAAQS.

Comments Submitted by Mrs. Scott and Ashley Wayman

57. Comment: The commenter states that the biological resources, parks and neighborhoods, including Verde Vale Elementary school, surrounding the proposed plant would be greatly affected in adverse ways. The commenter would like a larger area started within the forthcoming Environmental Impact Report.

Response: The AAQIR supporting the proposed action describes the legal and factual basis for the proposed permit, including requirements under the PSD regulations at 40 CFR §52.21. The AAQIR examines the potential impacts to air quality and biological resources as required under the PSD program. It is unclear from the comment above what larger area needs to be considered under this action.

58. Comment: The commenter has inquired as to how the new cogeneration unit will not continually violate air standards. What will the facility do about odor?

Response: The PSD permit with this action requires the facility to comply with applicable requirements under the PSD program. The permit requires BACT for NO_x, CO, PM, PM_{10} and $PM_{2.5}$. The emission limits in the permit will protect the NAAQS for NO_2, CO, PM_{10} and $PM_{2.5}$. Moreover, the permit contains monitoring, recordkeeping and reporting requirements to ensure that the facility complies with emission limits contained in the permit.

The PSD permit does not contain requirements directly regarding odor because odor is not a regulated NSR pollutant. Separately, odor is listed as an air contaminant in Shasta County District Rule 1:2. Moreover, District Rule 3:16 states that the Air Pollution Control Officer may place reasonable conditions upon any source that will mitigate the emissions of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or to the public, or which cause, or have the natural tendency to cause, injury or damage to business or property.

59. Comment: We ask that considerations be made to the cultural and historical sites within the proposed project site.

Response: The location for the modification at SPI- Anderson will be within the physical footprint of the current facility location. The facility is located at 19758 Riverside Avenue in Anderson, California 96007 (Assessor's parcel No. 050-110-025). The site is approximately 0.5 mile west of Interstate 5, and approximately 2 miles north of the city of Anderson. It is unclear what cultural or historical sites within the boundary of the current facility location need to be considered given that the Project will be located on SPI- Anderson's existing site.

Comments Submitted by Ms. Patricia Lawrence

60. Comment: Cumulative impacts of total air pollution in California's upper central valley have not been completely evaluated to include pollution from wildfires, increased vehicle and stationary sources of pollution, and air traffic pollution including chemtrails from jets in the federal weather modification program.

Response: The AAQIR, which describes the legal and factual basis for the permit, including requirements under the PSD regulations at 40 CFR §52.21, analyzed air quality impacts from the Project. The air quality impacts portion of the AAQIR assessed the impacts of the Project on ambient air quality. EPA concluded that the emission limits will protect the NAAQS. It is unclear from the commenter's statement why the background ambient air quality monitoring data does not include these incidents or how they will affect Project's ability to protect the NAAQS.

61. Comment: There is only so much clean air in the upper central valley where inversion layers are prevalent. Who gets the clean air and for what purpose? Why should a biomass plant be first over a solar panel manufacturer?

Response: As stated in the response to comment #60, the AAQIR assessed the impacts of the Project on ambient air quality and EPA concluded that the emission limits will protect the NAAQS.

Regarding the solar panel comment, please see the response to comment #13.

62. Comment: There may or may not be a steady or long lasting supply of biomass from the forests and wildlands. The applicant states that wood and 'other' biomass is proposed to be burned that will include household and industrial waste such as car tires. Even best available technology will not scrub all the dioxins from waste and tire burning.

Response: The new boiler will only be allowed to burn biomass, traditional non-waste fuel and not be permitted to burn waste that is not considered a traditional fuel. See response to comment #86. In particular, *Condition X.G.1.* in the PSD permit restricts fuel to natural gas and the following:

a. Untreated wood pallets, crates, dunnage, untreated manufacturing and construction wood debris from urban areas;
b. All agricultural crops or residues;
c. Wood and wood wastes identified to follow all of the following practices;
  i. Harvested pursuant to an approved timber management plan prepared in accordance with the Z'berg-Nejedly Forest practice Act of 1973 or other locally or nationally approved plan; and
  ii. Harvested for the purpose of forest fire fuel reduction or forest stand improvement.

The fuel restrictions in the PSD permit do not allow for the combustion of industrial waste or of car tires, and therefore the combustion characteristics from the burning industrial waste or of tires was not analyzed in the AAQIR for the Project.

63. Comment: Loss of California's natural forests due to clearcutting and conversion to tree farms and previous wildfires is releasing a huge carbon sink in these forests that needs to be protected to help reduce carbon in the atmosphere. What to do with accumulated biomass is a big problem in this state. Burning is not the only option. Chipping it and putting it back on the forest floor is another.

Response: The treatment of accumulated biomass within the state of California is beyond the scope of this PSD permitting action. To the extent that the Project should be subject to a BACT analysis for GHGs, EPA concluded that the PSD program did not apply to the Project for GHGs. The AAQIR identified an increase in GHG emissions that exceeds the "subject to regulation" threshold of 75,000 tpy CO_2e and the GHG significance rate of 0 tpy, however EPA's *Deferral for CO_2 emissions from Bioenergy and Other Biogenic Sources under the Prevention of Significant Deterioration and Title V programs* (76 FR 43490 July 20, 2011) applies to the Project. Since the non-deferred GHG emissions for this project are 38,252 tpy CO_2e, as calculated in Appendix A of the AAQIR, the modification is not subject to BACT for GHG.

64. **Comment:** The commenter requests a public hearing in order to address the issues raised in Comments #60-63 and all issues that this proposal evokes.

Response: Pursuant to 40 CFR 124.12, EPA must hold a public hearing if it, on the basis of requests, determines there is a significant degree of public interest in a draft permit. After distributing the public notice to the necessary parties in accordance with 40 CFR Part 124 and additional members of the public, EPA received comments from 15 members of the public, including the applicant, and three requests for a public hearing. None of the requests for a public hearing demonstrated that there was significant public interest in the Project; therefore EPA did not hold a public hearing. EPA reviewed and responded to all written comments from the public received during the public comment period.

Comments Submitted by Mr. Dave Brown, Environmental Affairs and Compliance Manager of Sierra Pacific Industries- Anderson Division

Sierra Pacific Industries (SPI) appreciates the opportunity to comment on the proposed PSD permit and supporting Ambient Air Quality Impact Report (AAQIR) for the SPI Anderson facility. While not specifically addressed in the PSD or AAQIR documents, it is noted that the overall facility permitting process for this project has included an Environmental Impact Report (EIR) to fulfill the requirements of the California Environmental Quality Act (CEQA) and approval of a Special Use Permit as required by Shasta County. That EIR similarly addressed Air Quality (including reference to the PSD permit and process), Climate Change, Soils, Traffic, Noise, Water Resources and other considerations. A public hearing was held for the initial scoping meeting, a second hearing at the Planning Commission for the EIR certification and Use Permit approval, and a third public hearing on appeal to the County Board of Supervisors (BOS), which upheld approval of the EIR and Use Permit. The Notice of Determination was filed following the BOS approval, which was not contested by any party within the 30-clay statute of limitations period following its issuance.

The comments below are first shown relative to the AAQIR document, followed by comments specific to the proposed PSD permit (and indicated in earlier comments of the AAQIR as applicable). It is understood that the AAQIR is the technical analysis that the actual PSD relies upon. While these comments are intended to correct minor inaccuracies and inconsistencies in the draft documents, the changes we have proposed do not affect the substantive analysis and would not require significant revisions to the AAQIR or the proposed PSD permit.

AAQIR

65. **Comment**: Boiler Design -Section 7.1.1 of the AAQIR indicates two general boiler technology designs, including stoker and fluidized bed. The stoker example (top of page 12, further defines Stoker to include "vibrating, traveling grate, etc." For purposes of clarity and relevance to the proposed boiler, the term 'step-grate' should be added to this description as the proposed boiler utilizes a mechanical step-grate for fuel distribution and neither a vibrating nor traditional traveling grate system. Similarly, the boiler should only be defined as "Stoker" without the additional definition for the grate type in other portions of the permit, including but not limited to the following:

Page 6- Table 4-1: Proposed New Equipment- need to strikeout the term "with vibrating grate" next to Stoker Boiler.

Response: EPA acknowledges the comments. Although we do not produce a revised AAQIR as part of our final permit decision, we reviewed these comments and determined that they do not require a change in our final permit decision or additional analysis of the basis for our determinations.

66. Comment: The NO_x mass emission limit shown "Step 5 -Select BACT" on page 16 is 60.8lb/hr (3-hour block average). This value is based on the 0.13lb/MMBtu (12- month rolling average) BACT limit. It would be more appropriate to base the mass emission limit based on the 0.15 lb/MMBtu (3-hour block average) BACT limit, in which case, the value would be 70.2 lb/hr (3-hour block average).

Response: EPA agrees that the 60.8 lb/hr mass emission limit should correspond to the 12-month rolling average and that 70.2 lb/hr mass emissions should correspond to the 3-hour block average as the applicant has appropriately noted. As the boiler for the project will have a rating of 468 MMBtu/hr, it can be readily verified that the product of 468 MMBtu/hr multiplied by 0.13 lb/MMBtu is 60.8 lb/hr, and that the product of 468 MMBtu/hr multiplied by 0.15 lb/MMBtu is 70.2 lb/hr. Therefore the mass emission limit on a 3-hour block average corresponding to the 0.15 lb/MMBtu BACT determination for NO_x should, in fact, be 70.2 lb/hr. Our proposed permit limit of 60.8 lb/hr (3-hour block average) was therefore erroneous. The final permit contains the correct limit of 70.2 lb/hr (3-hour block average).

The permit has been revised to incorporate the correct NO_x lb/hr mass emission limit for U1.

67. Comment: Misreference- The first sentence of the first paragraph in Section 6 (Applicability of the Prevention of Significant Deterioration Regulations) references Table 4. We believe the reference is actually to Table 6-1 and should be corrected accordingly.

Response: EPA acknowledges the comment. Although we do not produce a revised AAQIR as part of our final permit decision, we reviewed the comment and determined that it does not require a change in our final permit decision or additional analysis of the basis for our determinations.

68. Comment: PSD non-applicability- Table 6.1 of Section 6 (Applicability of the Prevention of Significant Deterioration Regulations) indicates that SO_2, VOCs, H_2SO_4, and Pb are each less than the significant emission rate, and, therefore, PSD does not apply. This is reiterated in Section 8.4, which says "As shown in Table 8.4-1, EPA does not expect SPI-Anderson to emit Pb, VOC, and SO_2 in significant amounts." In each of these determinations, the facility and its permit are not subject to BACT, Air Impact Analysis requirements, or conditions for each of these pollutants.

As explained above and in the EIR for this project, SO_2 emissions are not expected to exceed the PSD significant emission rate threshold, and, therefore, this pollutant is not subject to PSD regulations. As such, the SO_2 limit in Table 7.1-7 should be removed.

Response: The applicant correctly notes that BACT for SO_2 does not apply for the project, as noted in Table 6-1 of AAQIR. Therefore, EPA should not have included an emission limit for SO_2 corresponding to BACT emissions limits during startup and shutdown. EPA has removed the emissions limitation erroneously attributed to BACT for SO_2 during and startup and shutdown.

EPA does not produce a revised AAQIR as part of our final permit decision; however, we revised the final permit issued for the project in accordance with this comment.

69. **Comment:** Typographical Error- Table 6-1 and footnote 3 do not match with respect to CO_2e. We do not contest either quantity, simply that the final permit should have similar values. Similarly, the VOC emissions from Table 6-1 (34.9) do not match Table 8.4-1 (34.8).

The stack temperature associated with startup/shutdown operation shown in Table 8.3-1 should be 250 °F, not 294 °F.

Response: EPA acknowledges the comments. Although we do not produce a revised AAQIR as part of our final permit decision, we reviewed these comments and determined that they do not require a change in our final permit decision or additional analysis of the basis for our determinations.

70. **Comment:** Startup and Shutdown BACT limits- Section 7.1.3 provides a general description of startup and shutdown procedures relative to the boiler operations and otherwise excludes actual pollutant concentration operations during this period. Section 8.4.2 includes Analysis of startup and shutdown for emissions and indicates that "Startup CO emissions are expected to exceed those experienced during normal operating conditions." As such, startup and shutdown averaging periods longer than normal operations (3-hour) are warranted. The technical studies supporting the PSD permit considers 1 hour and 8 hour concentrations for modeling purposes. SPI respectfully requests that for startup and shutdown the averaging limits may remain unchanged in Table 7.1-7, but the averaging times should be changed to hourly concentrations (8-hour average) for CO and NO_x.

Response: The final permit has been revised to show that the averaging times for the NO_x and CO emission limits during startup and shutdown are based on an 8-hour average. The mass limits remain unchanged. EPA has also added *Condition X.C.2.* which states that "CO emissions at all times from U1, including startup and shutdown events as defined *Conditions X.D.3. and X.D.4.*, shall not exceed 432 lbs/hr (hourly average)." *Condition X.C.2.*, in conjunction with the other CO emission limits for U1 in the final permit, constitute EPA's BACT determination for CO from U1.

As noted in the AAQIR for the Project, SPI-Anderson expects periods of startup and shutdown to be infrequent in nature. In its March 2010 application, the applicant stated that it typically shuts down its boilers at least twice per year for maintenance. *Conditions X.D.3.and X.D.4* in the PSD permit for the Project define startup and shutdown periods for the boiler and state that the generator shall be separated from the electrical grid during these periods. By separating the generator and consequently disallowing sale of electricity to the grid during periods of startup and shutdown, SPI does not have a financial incentive to operate the boiler in states of startup or shutdown. Therefore, EPA believes that the emissions experienced during periods of startup and shutdown will occur on an infrequent basis.

Although EPA has increased the averaging period of NO_x during startup and shutdown, an updated modeling analysis for the 1-hour NO_2 NAAQS was not conducted. As noted in EPA's guidance memorandum dated March 1, 2011, EPA believes that it is inappropriate to implement the 1-hour NO_2 standard, which is expressed in a statistical form, in a manner that compliance demonstrations be based on emission scenarios that can logically be assumed to be relatively intermittent. When EPA is the reviewing authority for a permit, we will consider it acceptable to limit the emission scenarios included in the modeling compliance demonstration for the 1-hour NO_2 NAAQS to those emissions that are continuous enough or frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations, rather than for startup and shutdown events that may occur on a relatively infrequent basis. *See* online docket I.40: *Additional Clarification 1hr NO2 Modeling-Fox_01MAR11* at 9-10 in online docket.

In addition, although EPA has increased the averaging period for CO during startup and shutdown, an updated modeling analysis for the 1-hour CO NAAQS was not necessary because this modeling analysis has already been conducted. Table 7.1-7 of the AAQIR, which contains BACT emission rates during startup and shutdown, relied on values presented in Table 5 of SPI's May 30, 2012 submission. The values presented in SPI's Table 5, however, are somewhat inaccurate. *See* online docket #I.11: *SPI-Anderson_updated_modeling_and_SUSD_analysis-final_30MAY12*. This flaw, however, is minor since the footnote to SPI's Table 5 clearly states that modeled impacts for the CO were estimated using a mass emission rate of 432 lbs/hr (1-hour average). As shown in Table 8.3-1 of the AAQIR, Project-only modeled impacts reflect that modeling based on values of 432 lbs/hr (1-hour average) and 108 lbs/hr (8-hour average) was conducted. For this reason, EPA has also added *Condition X.C.2.* to the final permit to limit CO emissions to 432 lb/hr (1-hour average) in addition to the startup and shutdown mass emissions limit for CO of 108 lbs/hr (8-hour average).

For further discussion, please see the response to comment #50. Permit *Condition X.D.5* has also been changed to reflect the 8-hour averaging period.

71. Comment: Determination of Compliance- Section 7.2, Step 5 (page 24) selects BACT for the Emergency Engine. An emergency engine is typically not subject to annual source testing to determine compliance. Rather, to avoid the impracticality of source testing, compliance may be achieved by providing performance specifications from the manufacturer to meet or exceed the g/kW-hr (on a 3-hour max rolling average) as specified in Table 7.2-3.

Response: EPA has determined that the following is BACT for the Emergency Engine:

BACT for 191 kW Emergency Engine		
Pollutant	**Limit**	**Averaging Time**
NO_x	0.78 (lb/hr)	Hourly
CO	4.0(g/hp-hr)	3- Hour
PM, PM_{10}, $PM_{2.5}$	0.0216 (lb/hr)	Hourly

These limits are set forth in Table 6 of the final permit. *Condition X.I.4.* of the final permit requires an initial performance test as set forth in 40 CFR §60.4244, and at least every five years beginning ten years after the initial performance test. *See* the Appendix to this document for more information on the BACT determination for the emergency engine.

EPA has updated the equipment description for this emissions unit in the final permit to be a spark-ignition (SI) internal combustion, natural gas-fired emergency engine. As stated in the BACT analysis and the final permit, the emergency engine shall comply with 40 CFR Part 60 Subpart JJJJ. Moreover, *Condition X.G.3.* has been added to the final permit which states that "the heat input to U3 shall only be PUC-quality pipeline natural gas."

EPA has removed the testing requirement for PM_{10} from the emergency engine from *Condition X.H.4.* in the proposed permit. EPA acknowledges that emissions from SI emergency engines combusting pipeline natural gas have low PM_{10} emissions and that 40 CFR Part 60 Subpart JJJJ does not contain PM_{10} emission limits or require monitoring or performance tests for PM_{10} emissions, In order to demonstrate compliance with the PM/PM_{10} emissions limit in Condition X.E.1, the permittee shall comply with *Conditions X.G.3.* and *X. J.10.* in the final permit. *Condition X.J.10.* states that "[f]or U3, the permittee shall maintain records of the following: hours of operation, purpose of operation, fuel usage on hourly basis and calculated PM/PM_{10} emissions base on manufacturer emissions specifications and fuel usage data."

72. **Comment**: In the first sentence of Section 7.2.1 (NO_x, CO, PM, PM_{10}, $PM_{2.5}$ Emissions), Step I-Identify all control technologies, "catalyzed diesel particulate filter" should be removed from the list. The proposed engine is a natural gas-fired, spark-ignition engine, and use of that control would not be appropriate. Similarly, the last sentence of that same paragraph should be removed.

Response: The Appendix to this document contains an updated BACT analysis for the natural gas-fired spark ignition emergency engine. The revised BACT analysis does not identify the diesel particulate filter or a particulate filter trap as appropriate control technologies for this unit.

73. **Comment:** The NSPS limits provided in Table 7.2-1 (NSPS Limits for Engines) and Table 7.2-3 are from Subpart IIII, which covers compression-ignition engines. Limits from

Subpart JJJJ, which covers spark-ignition engines should be used instead. We suggest that Table 7.2-1 and Table 7.2-3 should appear as follows:

Table 7.2-1: NSPS Limits for 191 kW, Natural Gas-Fired, Spark-Ignition Engines

Engine Type	NO_x (g/hp-hr)	CO (g/hp-hr)	PM (g/hp-hr)
Non-emergency engine	1.0	2.0	0.7
Emergency Engine	2.0	4.0	1.0

Table 7.2-3: Summary of BACT for 191 kW, Natural Gas-Fired, Spark-Ignition Emergency Engine

Engine Type	NO_x (g/hp-hr)	CO (g/hp-hr)	PM (g/hp-hr)
Emergency Engine	2.0	4.0	1.0

Similarly, Table 7.2-2, which reflects the limits from Subpart IIII instead of Subpart JJJJ, should appear as follows:

Table 7.2-2: Summary of PTE for 191 kW, Natural Gas-Fired, Spark-Ignition Emergency Engine

Pollutant	Emergency Engine (tpy)
NO_x	0.056
CO	0.11
PM	0.028

Response: The Appendix to this document contains an updated BACT analysis for the natural gas-fired spark ignition emergency engine. The revised BACT analysis incorporates the appropriate emissions limits from 40 CFR Subpart IIII; however, the PTE summary for NO_x and PM have not changed from the proposal as the PTE limits for those pollutants were based on more stringent emissions limits supplied by the applicant's consultant in an April 26, 2012 email. See the Appendix for more detail.

74. Comment: Typographical Error- Section 7.3 under "Wet Cooling" (bottom of page 24) should indicate a three-cell cooling tower, not a two-cell cooling tower. This was reflected in the May 30, 2012 Updated Air Dispersion Analysis prepared by Environ and identified in the PSD permit.

To be consistent, the NO_2 annual NAAQS entry in Table 8.4-3 (SPI-Anderson Compliance with Class II PSD Increments and NAAQS) should read: "100 (53 ppb)."

Response: EPA acknowledges the comment. Although we do not produce a revised AAQIR as part of our final permit decision, we reviewed this comment and determined that it does not require a change in our final permit decision or additional analysis of the basis for our determinations.

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75. Comment: As stated in #6 above, the description of the cooling tower in the second paragraph under Project Description, and of ID U2 in Table 1, should be changed to read "three-cell," instead of “two-cell."

Response: The permit has been revised to incorporate the suggested language. EPA notes that this revision is descriptive in nature and does not have any substantive effect on the permit or EPA’s analysis of the Project.

76. Comment: As stated in #1 above, the term "with Vibrating Grate" should be removed from Table 1.

Response: This term has been deleted from PSD Permit SAC 12-01. EPA notes that this revision is descriptive in nature and does not have any substantive effect on the permit or EPA’s analysis of the Project.

77. Comment: Malfunction Reporting- Section IV of the PSD permit includes provisions for the Permittee to notify EPA for malfunctions. This is atypical of similar operating permits and usually reported directly to the designated Air District and otherwise copied to EPA as part of regular reporting. It may be desirable to add an item "D." to this section that allows for items IV.A thru C to be waived if notification is submitted to the Air District.

Response: Section IV will remain unchanged. EPA is currently the PSD permitting authority in the District. As a result, the permittee must report malfunctions to EPA Region 9. The PSD permit authorizes the construction and operation of emissions units associated with the Project; however it is not an Operating Permit under title V of the Clean Air Act. If the District adopts the PSD permitting program, then the permittee may request a permit revision that removes reporting requirements to EPA.

78. Comment: Typographical Error: Section X- Table 3 -the values for PM, PM_{10}, and $PM_{2.5}$ (each at 41) do not match the AAQIR values (each at 42.1 respectively).

Response: This is not a typographical error. The values in Section 6 of the AAQIR reflect the changes in emissions resulting from the project, including estimates from the emergency engine and the cooling tower. Table 3 limits emissions only from the new boiler. The increase in emissions from the AAQIR, particularly for PM, is attributable to the PM emissions from the cooling tower and the emergency engine.

79. Comment: Air Pollution Control Equipment and Operations- Section X.B specifies for control equipment to operate continuously, but does not restrict this to operation of the boiler itself. It is impractical, and with respect to the electrostatic precipitator (ESP), can severely damage control equipment to operate without the boiler. As such, the sentence should be rephrased to indicate "During Boiler operations, Permittee shall continuously operate...".

Response: The permit has been revised to incorporate the suggested language regarding the air pollution control technologies during boiler operations. EPA notes that this revision is descriptive in nature and does not have any substantive effect on the permit or EPA's analysis of the Project.

80. **Comment:** The last sentence in this paragraph [Paragraph X.B.] is similarly concerning and indicates "Permittee shall also perform any necessary operations to minimize emissions so that emissions are at or below the emission limits specific in this permit." This implies that if conditions warrant, that the Permittee is required to minimize emissions potentially less than permitted. This creates subjectivity to the term "emission limits" and reduces the ability of the Permittee to perform adjustments to fine-tune, utilize approved fuels, or similar measures would otherwise be allowed at or below emission limits. As emission limits are already defined, this sentence is unnecessary and should be deleted in its entirety.

Response: EPA has replaced this language with the following: Permittee shall also to the extent practicable, maintain and operate equipment in a manner consistent with good air pollution control practice for minimizing emissions. This requirement imposes an obligation substantially similar to 40 CFR. §60.11(d) and encourages SPI to follow industry standards for reducing air emissions.

81. **Comment:** Natural Gas Usage- As stated in #3 above, SO_2 emissions from the proposed project are not subject to PSD review. Section X.D.I of the PSD (page 7 of 17) indicates requirements for PUC-quality pipeline natural gas and limits of 0.20 grains per 100 dry standard cubic feet (dscf) on a 12-month rolling average basis and not to exceed 1.0 grains per 100 dscf at any time. This requirement is not warranted by this PSD permit for SO_2 and should be deleted. If not deleted, the requirement should be limited to providing PUC-quality natural gas and no requirements for sulfur content. SPI has spoken with PGE on available natural gas. While it is PUC grade, the sulfur content appears to periodically exceed the 0.20 grains/dscf throughout most of the state, including the Shasta County area. The current wording would potentially prohibit the facility from operating and as indicated above should not be restricted or limited by this permit. While we recognize that Sulfur in natural gas can contribute to PM emissions, the BACT determination including the ESP does not rely upon this for its determination and we respectfully request the change incorporated above.

Response: EPA considered pipeline natural gas in the BACT analysis for particulate matter as a means to reduce emissions of particulate from the Project due to its low sulfur content. In order to verify that the Project is utilizing low sulfur fuels, especially during startup and shutdown, the permit will continue to contain requirements that restrict the natural gas being combusted in U1 and U3 to Public Utility Commission (PUC)-quality pipeline natural gas. EPA agrees that specific sulfur content requirements may be difficult to achieve at the facility given the infrequent use of natural gas, As a result, sulfur content requirements on a grain per dry standard cubic foot basis have been removed from *Condition X.D.1.* Although *Condition X.D.1.* has been revised, PM, PM_{10}, $PM_{2.5}$ emissions limits for U1 have not changed from the proposed permit.

EPA notes that particulate emissions from the combustion of PUC- quality pipeline natural gas are expected to be lower than particulate emissions resulting from the combustion of biomass. In addition, *Condition X.G.2.* in the final permit restricts the heat input to U1 on a 12-month rolling basis and, as noted in the response to comment #70, startup and shutdown events are expected to be infrequent in nature.

82. Comment: PSD Non-Applicability and Startup Averaging Periods- As stated in #4 and #6 above, SO_2, VOC, and Pb emissions from the proposed project are not subject to PSD review. Therefore, the PSD permit should not include emission limits or permit conditions associated with these pollutants as in Table 5, item D.8, and Section H. All conditions associated with VOC, SO_2 and Pb should be deleted from the permit. Averaging periods in Table 5 should be changed as indicated in #6 above.

Response: EPA has removed the SO_2 emission limits from Table 5 and on *Condition X.D.8*. However, EPA has retained the initial source test requirements for VOC, SO_2 and Pb. EPA agrees that the source is not subject to PSD for SO_2, Pb, or VOC as outlined in the AAQIR. As outlined in SPI's 2010 application, SPI used AP-42 emission factors with fuel input throughput figures to estimate the potential to emit of the source. These estimates, however, are not based on specific fuel characteristics used on site. While the permit contains adequate fuel conditions that justify the technical assumptions in the AAQIR, EPA also recognizes that biomass may have a variable emissions profile depending on the cellulosic material that is combusted. Therefore, EPA believes the initial source test conditions for SO_2, VOC, and Pb are not excessively burdensome and are appropriate in this case.

EPA has revised the averaging times for emissions limits during periods of startup and shutdown in the final permit. See response to comment #70 for more discussion.

83. Comment: Auxiliary Equipment Emissions Limitations- In Table 6 of Section X.E.1, the PM/PM10 emission limit on U2 (the cooling tower) should be 0.272 lb/hr (hourly average), instead of 0.26 lb/hr.

Response: EPA acknowledges that the proposed permit included the improper hourly average emissions limit for PM/PM_{10} for U2. In a May 2012 submission, the applicant revised the PM/PM_{10} hourly emissions rate of 0.272 lb /hr from the cooling tower and included a revised modeling analysis for the Project's modeled impacts in the AAQIR reflected an hourly PM/PM_{10} emissions rate of 0.272 lb/hr from the cooling tower. *See* online docket #I.11: *SPI-Anderson_updated_modeling_and_SUSD_analysis-final_30MAY12* at Table 5. EPA has revised Table 6 in *Condition X.E.1.* in the final permit to show that emissions of PM/PM_{10} from U2 shall not exceed 0.272 lbs/hr. EPA's BACT determination for PM/PM_{10} emissions for U2 (cooling tower) on a lb/hr basis is *Condition X.E.1.* in the final permit.

84. Comment: Auxiliary Equipment Emissions Limitations-In Item I, Table 6, the NO_x, CO, and PM/PM_{10} emission limits shown for U3 (the emergency boiler recirculation pump engine) are taken from NSPS Subpart IIII for compression ignition engines, where they should have been taken from NSPS Subpart JJJJ, as indicated in #6 above. In *Section*

X.E.2, the reference to fire safety testing should be removed, as U2 is not used for fire safety.

Response: The permit has been revised to incorporate the appropriate emission limits following a revised BACT analysis for the emissions unit. For more detail, see the response to comment #9 and the Appendix to this document.

EPA acknowledges the commenter's clarification that the emergency engine is used for the water recirculation pump as needed, and not for fire safety purposes. Therefore, the reference to fire safety testing has been removed from *Condition X.E.2*.

85. Comment: Operating Conditions and Work Practices-Section F. Item 7 refers to wood waste and storage bins and the requirement that these remain enclosed. The (wood) fuel shed, is by design, an open sidewall system and is not part of any pressurized or temporary bin. The phrase "not including the fuel shed" will clarify how this item is interpreted for compliance purposes.

Item 14 indicates "All leaks, spills and upsets of any kind shall be corrected or cleaned with 4 hours." It is assumed and needs clarification that this does not include any upset that may occur related to U1, U2, or U3 and that "with" was intended to be "within" 4 hours. Certain upset conditions may require timeframes longer than 4 hours, daylight hours, business hours, or other conditions that would otherwise prohibit compliance with this item. Please clarify the intent of this requirement and add the terms "as practicable".

Item 16 and 17- VOCs were indicated below SERs for this permit and conditions for VOCs should not apply.

Response: The permit has been revised to incorporate the language regarding the fuel shed.

Regarding *Condition X.F.14,* EPA incorrectly incorporated a wood waste and collection storage condition and has corrected the permit. This condition has been combined with *Condition X.F.5. Condition X.F.5.* now states, in entirety, "Wood waste collection and storage bin leaks shall be minimized at all times. All identified wood waste collection and storage bin leaks, spills and upsets of any kind shall be corrected or cleaned immediately, within 4 hours, as practicable, to correct the leak, spill or upset."

The permit will retain the work practice standards relating to volatile organic waste and containers possibly holding VOCs or volatile organic waste. As demonstrated in the AAQIR the Project was below the significant emission rate for VOCs, however these conditions represent reasonable work practice standards that may prevent or reduce the incidence of fire and other possible sources of additional air pollution.

86. Comment: Fuel Restrictions- Section F.2 specifies fuels different than those applied for in the PSD application by the Permitee, which included:
(from the PSD Application, Section 2.2 Fuel Supply)

"Fuel for the cogeneration unit will come from the existing SPI facilities in California at Arcata, Anderson, Shasta Lake, and Red Bluff, as well as in-forest materials from SPI-owned or controlled timberlands, and various sources of agricultural and urban wood wastes". This description has remain unchanged during the PSD process with EPA and would request that it either remain for the PSD permit, or be modified to reflect the wording below, as approved by the EIR and Special Use Permit. This wording is slightly more restrictive although not substantively different than originally proposed to EPA in the PSD application and is supported by the modeling and technical analysis for the proposed PSD.

The fuel description in the draft PSD is not consistent with the PSD application or the technical analysis and modeling supporting this project and would be inconsistent with the proposed operation of the facility.

(from the approved EIR and Special Use Permit, Shasta County- Use Permit 07-021, Condition 91 respectively)

Fuels burned in the cogeneration boiler shall be limited to the following:
a. Waste pallets, crates, dunnage, manufacturing and construction wood wastes, tree trimmings, mill residues, and range land maintenance resides;

b. All agricultural crops or waste;

c. Wood and wood wastes identified to follow all of the following practices;
   a. Harvested pursuant to an approved timber management plan prepared in accordance with the Z'berg-Nejedly Forest practice Act of 1973 or other locally or nationally approved plan; and

   b. Harvested for the purpose of forest fire fuel reduction or forest stand improvement.

Response: EPA is familiar with the fuel terminology proposed in the application. However, the facility will only be allowed to burn biomass, traditional non-waste fuel and not be permitted to burn waste that is not considered a traditional fuel. The source is not considered a solid waste incinerator and has not satisfied the appropriate performance standards requirements associated with commercial and industrial solid waste incinerators.

EPA understands the source's interest in streamlining its fuel definitions with other regulatory agencies. However, the source will not be able to burn waste that is not considered a traditional fuel. Therefore, *Condition X.G.1.* in the PSD permit restricts fuel to natural gas and the following:

a. Untreated wood pallets, crates, dunnage, untreated manufacturing and construction wood debris from urban areas;
b. All agricultural crops or residues;
c. Wood and wood wastes identified to follow all of the following practices;

i. Harvested pursuant to an approved timber management plan prepared in accordance with the Z'berg-Nejedly Forest practice Act of 1973 or other locally or nationally approved plan; and

ii. Harvested for the purpose of forest fire fuel reduction or forest stand improvement.

87. Comment: Performance Tests- As indicated earlier in item 14 above, no performance testing is warranted by this PSD permit for items H.1.e (Pb emissions), H.1.b (SO_x emissions), and Item 2.a (both for SO_2 and Pb emissions) and these should be respectfully removed from the proposed PSD permit. Similarly item 2.c does not provide any flexibility from the facility's maximum steam production rate for PM testing. In practical application, a percentage of the maximum steam rate is applied to allow operational flexibility while maintaining permit limits. To this extent, we request that the PSD permit allow for a 90% of the maximum steam rate for performance testing.

Item H.3.d (cooling tower) requires establishment of procedures to ensure TDS limits are not exceeded. With a 0.0005% drift rate, TDS is not measurable in practice and unnecessary at that performance standard. This item should be deleted in its entirety in consideration of the drift rate imposed.

Item H.6 for sulfur gas content-similar to item 13 above. This item is unnecessary and not warranted as a condition for this permit and appears unachievable based on review of available natural gas supplies (PGE). Similarly, PGE performs testing on entire service areas, not specific distributions to facilities. As such, the requirement for the Permittee to ensure that the fuel tested is representative of the fuel delivered to the site is impractical to achieve. Instead, we request that the PSD permit request that the permittee provide sulfur content reports (from the PUC Quality Natural Gas distributor- PGE in this instance) with no numerically defined requirement on the sulfur content.

Response: EPA has retained the initial source test requirements for VOC, SO_2 and Pb because EPA believes the initial source test conditions for SO_2, VOC, and Pb are not excessively burdensome and are appropriate in this case. See response to comment #82 for further discussion.

EPA disagrees with applicant’s comment regarding PM testing in *Condition X.I.2.c.* PM testing shall be performed at the maximum steam rate with the appropriate fuel according the manufacturer’s specifications. As stated in *Condition X.I.5.* “Upon written request from the Permittee, and adequate justification, EPA may waive a specific annual test and/or allow for testing to be done at less than maximum operating capacity.” The applicant has not provided sufficient information for the maximum steam rate requirement to be permanently waived.

EPA acknowledges that the permit does not establish limits for total dissolved solids (TDS). However, the permittee will still be required to establish maintenance procedures that ensure the integrity of the drift eliminators and compliance with recirculation rates. Moreover, the permittee will still be required to comply with PM/PM_{10} emission limits from U2 as specified in X.E.1. rates and calculated according to Condition X.I.3.b. Condition X.I.3.d. in the final permit states that the permittee shall do the following. :

"Establish a maintenance procedure that states how often and what procedures will be used to ensure the integrity of the drift eliminators and to ensure compliance with recirculation rates. This procedure is to be kept onsite and made available to EPA and District personnel upon request. The permittee shall promptly report any deviations from this procedure."

The permit has been revised (*See Condition X.J.1*) to incorporate the suggested language regarding the record of sulfur content reports for natural gas used on site.

88. **Comment:** Recordkeeping and Reporting – Item I.9 of the PSD permit indicates "for U1, daily records of fuel received other than natural gas shall be maintained. These records shall include a detailed description of fuel supplier, fuel type and tons received." U1 receives fuels from the facility itself that are directly conveyed to the fuel delivery and handling system. The facility similarly receives fuels from outside sources that are weighed and tracked - for purposes of this comment, these are facility received or inbound fuels. Item I.9 should clarify that on-site derived fuels are exempt from recordkeeping regarding tonnage. For purposes of determining compliance, estimates of fuels may be derived from the boiler rating, steam flow, and heat value of the fuel (onsite or offsite) to determine an overall usage.

Response: *Condition X.J.9* (Condition X.I.9 in the proposed permit) will remain unchanged. The BACT determinations for the Project and the emissions limits for U1in the final permit are on a lb/hr and lb/MMBTU heat input basis. In its application SPI stated that the boiler will be rated at 468.0 MMBTU/hr based on heat input. *See* online docket #I.01: *SPI-Anderson PSD Permit Modification Application_25MAR10* at 3. In order to readily verify compliance with the emission limits and fuel conditions in the permit, the permittee must be able demonstrate that all fuel combusted in U1 is appropriately monitored and recorded. All fuels, including those derived on-site, must comply with fuel conditions in *Section X.G.* of Permit SAC 12-01. Without appropriately accounting for all fuel received the permittee would seemingly be able to inappropriately back-date, potentially mislabel and assume that all unaccounted materials combusted in U1 were compliant fuels generated onsite.

Appendix

BACT for Emergency Engine

The project includes a 256hp (191kW) natural gas-fired spark ignition emergency engine to run a water recirculation pump for the boiler. The limited operation of this unit results in minimal annual emission rates. This equipment is subject to BACT for NO_x, CO, PM, PM_{10}, $PM_{2.5}$.

In the AAQIR and draft permit, EPA incorrectly identified the proposed emergency engine as a compression ignition natural gas engine. During the public comment period, the applicant noted that the proposed unit was, in fact, a spark ignition natural gas fired emergency engine. Taking this information into account, EPA has revised its BACT analysis for the emergency engine.

A top-down BACT analysis has been performed for the spark ignition emergency engine and is summarized below.

7.2.1 NO_x, CO, PM, PM_{10}, $PM_{2.5}$ Emissions

Step 1 -- Identify all control technologies

The control options for NO_x emissions from engines include SCR, NO_x reducing catalyst, NO_x adsorber, catalytic converter, and oxidation catalyst. A catalytic converter and oxidation catalyst are also control options for CO emissions.

The emergency engine will be required by the final permit to be in compliance with NSPS requirements, including emission limits. The emergency engine will also be subject to operational restrictions. Different types of engines have different emission requirements based on the type of engine being purchased. Engine manufacturers may need to employ some of the control technologies identified above in order to comply with the NSPS emission limits, depending on the type of engine and the applicable limits. The applicant is proposing to install an emergency engine for infrequent recirculation pump needs. At a minimum, SPI must purchase an engine that complies with the NSPS and meets the emission requirements for emergency engines. However, we note that the applicant could purchase an engine that meets the NSPS standards for non-emergency engines, which have more stringent limits, and operate it as an emergency engine. As a result, this review identifies the control technologies to be:

- NSPS-compliant emergency engine
- NSPS-compliant non-emergency engine
- Operational restrictions (e.g., limits on the hours of operation)

Step 2 – Eliminate technically infeasible control options

All of the control technologies identified are assumed to be technically feasible.

Step 3 – Rank remaining control technologies

The available control technologies are ranked according to control effectiveness in Table 7.2-1.

Engine Type (191kW)	**NO_x (g/hp-hr)**	**CO (g/hp-hr)**
Non-emergency engine	1.0	2.0
Emergency engine	2.0	4.0

The NSPS for spark ignition internal combustion engines does not contain emissions limits for PM, PM_{10} or $PM_{2.5}$. However, the applicant submitted emissions estimates for the emergency engine that are more stringent than the NSPS standards for a natural gas spark engine for NO_x and PM, PM_{10} and $PM_{2.5}$ in an email on April 26, 2012. *See* online docket I.31: *SPI-Anderson to EPA re Emergency Engine Emissions 26APR12*.

Step 4 – Economic, Energy and Environmental Impacts
Due to economic impacts and limited environmental benefit, requiring add-on controls or compliance with the NSPS for non-emergency engines would be impractical in this case. The additional emission reductions would have very little environmental benefit and not justify any additional cost. We note that the expected emissions from the emergency engine are 226 lbs/year of CO, 78 lbs/year of NO_x and 3 lbs/year of PM.

The draft permit contained an hourly NO_x emission limit for the emergency engine that is more stringent than those found in 40 CFR Part 60 Subpart JJJJ for spark ignition emergency engines. This hourly limit was used to assess annual PTE of the emergency engine in the AAQIR and has not changed.

In addition, the draft permit contained hourly emissions limits for PM, PM_{10} and $PM_{2.5}$. The current NSPS for spark ignition natural gas fired engines does not have limits for PM, PM_{10} and $PM_{2.5}$. The hourly limit in the draft permit was used to asses annual PTE of the emergency engine in the AAQIR and has not changed.

The draft permit also contained an hourly CO emissions limit that is less stringent than the 40 CFR Part 60 Subpart JJJJ limits for emergency spark ignition engines; in the final permit, EPA will include the more stringent Subpart JJJJ emergency engine emissions limit. Our revised calculation of annual PTE for the emergency engine reflects this NSPS limit.

As illustrated in Table 7.2-2 the potential emissions from the emergency engine (based on 100 hours of operation per year and complying with permitted and NSPS for natural gas spark ignition emergency engines) has not changed for NO_x and PM, PM_{10} and $PM_{2.5}$ and revised lower for CO. A thorough review of other BACT determinations was not performed because it is very unlikely that a more detailed review would change the final determination due to the annual emission rates associated with the proposed limits and the operational restriction of 100 hours annually.

Table 7.2-2: Summary of PTE for 191 kW Emergency Engine

Pollutant	Emergency Engine (tpy)
NO_x	0.039
CO	0.11
PM, PM_{10}, $PM_{2.5}$	0.0011

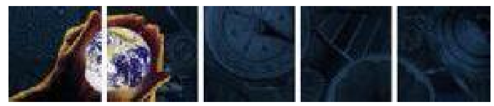
Step 5 – Select BACT

Based on a review of the available control technologies, we have concluded that BACT is limiting the hours of operation to 100 hours and the permitted emission limits listed in Table 7.2-3. It is assumed that newly purchased engines would be the most energy efficient available and that operating in compliance with NSPS requirements will ensure that each engine is properly maintained and as efficient as possible. Again, we note that the expected emissions from the emergency engine are 226 lbs/year of CO, 78 lbs/year of NO_x and 3 lbs/year of PM.

Table 7.2-3: Summary of BACT for 191 kW Emergency Engine			
Pollutant	**Limit**	**Averaging Time**	**Source**
NO_x	0.78 (lb/hr)	Hourly	Permit
CO	4.0(g/hp-hr)	3- Hour	NSPS
PM, PM_{10}, $PM_{2.5}$	0.0216 (lb/hr)	Hourly	Permit

Excerpt 4

SPI Anderson PSD Permit Modification Application, dated March 25, 2010 (“March 2010 Application”), AR I.01 (pages 1-39 only)



Biomass-Fired Cogeneration Project Authority to Construct and Prevention of Significant Deterioration Permit Application

Anderson, California

Prepared for:
Sierra Pacific Industries
Redding, California

Prepared by:
ENVIRON International Corporation
Lynnwood, Washington

Date:
March 2010

Project Number:
29-23586A

ENVIRON

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1 Introduction

Sierra Pacific Industries (SPI) proposes to construct and operate a cogeneration unit at an existing lumber manufacturing facility located in Anderson, California. The boiler associated with the proposed cogeneration unit will burn biomass fuel (i.e., non-treated wood and agricultural crop residues, as well as urban wood-waste and other fuels subject to district approval) generated by the facility, regional lumber manufacturing facilities, and other biomass fuel sources to produce approximately 250,000 pounds of steam per hour. The steam will be used to dry lumber in existing kilns and for a steam turbine; the steam turbine will drive a generator that will produce electricity for on site use as well as for sale to the grid. Although no steam sales agreements are currently in place, steam may also be sold to other nearby businesses. The existing biomass-fired boiler will remain operational, but will not operate concurrently with the proposed unit other than periods of operational overlap necessary to ensure adequate uninterrupted steam production.

Because the existing lumber manufacturing facility is a major stationary source of emissions, and the proposed cogeneration unit is considered a major modification, a Prevention of Significant Deterioration (PSD) permit must be obtained. On March 3, 2003, the U.S. Environmental Protection Agency (USEPA) withdrew the PSD delegation from several authorities in USEPA Region IX, including Shasta County Air Quality Management District (AQMD), making USEPA the PSD permitting authority for Shasta County. However, AQMD issued the initial PSD permit for the Anderson facility in 1994. Additionally, AQMD Rule 2-1A requires a new or modified emission source to obtain an Authority to Construct (ATC) from the AQMD prior to commencing construction. SPI has retained ENVIRON International Corp. (ENVIRON) to prepare a combined ATC/PSD permit application to be submitted to the AQMD on its behalf.

This permit application is a revision and update of a permit application for a similar project involving a smaller version of the same boiler design (200,000 pounds steam per hour instead of 250,000 pounds of steam per hour) that was submitted to the AQMD in May 2007. In addition to revising the emission rate calculations and regulatory analysis to reflect the currently proposed boiler, the air quality modeling was updated to reflect the most current versions and guidance.

1.1 Organization

The key components of this permit application are:

- A description of the project and expected air pollutant emissions;
- A discussion of applicable air quality regulations;
- An analysis of Best Available Control Technology (BACT); and
- Analysis of compliance with ambient air quality standards.

Standard forms related to the ATC process are provided in Appendix A.

1.2 Summary of Findings

ENVIRON conducted an air quality impact assessment of the project using five years of hourly meteorological surface data collected at Redding Municipal Airport between January 1, 2004 and December 31, 2008. The analysis indicates that predicted ambient air pollutant concentrations attributable to the project will not cause or contribute to an exceedance of the National or California Ambient Air Quality Standards (NAAQS or CAAQS) established to protect human health and welfare, nor increase the ambient concentrations in excess of the PSD increments established to prevent deterioration of the area's existing air quality.

ENVIRON also conducted a screening analysis to determine the need to assess air quality related values (AQRVs) including regional haze, nitrogen and sulfur deposition and the effects of primary and secondary pollutants on sensitive plants and soils at Class I areas in the region. The screening analysis determined that a regional AQRV modeling analysis was not necessary.

2 Project Description

2.1 Physical Description

Sierra Pacific Industries (SPI) is a family-owned wood products company based in Redding, California. SPI currently operates an existing lumber manufacturing facility in Anderson, California. SPI intends to construct a new cogeneration unit at the Anderson facility that would burn biomass fuels in a boiler to produce steam that would be used to generate electricity and to heat existing lumber dry kilns at the facility.

The cogeneration unit will consist of a biomass-fired water-wall boiler with a vibrating grate, a steam turbine, and a generator. The boiler will burn biomass fuels to produce high-pressure steam for the steam turbine. The steam turbine generator will generate up to 23 megawatts (MW) of electricity. Approximately 7 MW will be used to power on-site equipment; the remainder will be sold to a public utility. Low-pressure steam will be extracted from the steam turbine through a controlled extraction and used to heat the dry kilns.

The final design of the biomass-fired boiler has not been determined, but it will be similar to a unit designed by the McBurney Corp. of Norcross, Georgia. It will have a maximum annual average design heat input of approximately 425.4 million British thermal units per hour (MMBtu/hr) and a maximum steam generation rate of 250,000 pounds per hour (lb/hr). Over short-term periods, the boiler will have the capacity to be fired at heat input rates that exceed the annual average rate: an hourly maximum of 468.0 MMBtu/hr (10 percent greater than the annual average), and a maximum 24-hour average of 446.7 MMBtu/hr (5 percent greater than the annual average). The boiler will be equipped with two natural gas burners, each with a maximum rated heat input of 62.5 MMBtu/hr, for start up and flame stabilization. The cogeneration unit design will incorporate a selective non-catalytic reduction (SNCR) system that uses annhydrous ammonia to reduce emissions of oxides of nitrogen (NO_X), as well as a multiclone and electrostatic precipitator (ESP) to control emissions of particulate matter (PM/PM_{10}). A closed-loop two-cell cooling tower will be used to dispose of waste heat from the steam turbine. A schematic flow diagram for the cogeneration facility is presented in Figure 2-1.

The proposed cogeneration unit will be located near the existing biomass-fired boiler at SPI's Anderson lumber manufacturing facility. The existing facility is bordered on the northeast by the Sacramento River, on the northwest by a private parcel, on the southwest by Union Pacific Railroad tracks and State Route (SR) 273, and on the southeast by private parcels. The general vicinity of the facility and the modeling domain are shown in Figure 2-2.

2.2 Fuel Supply

Fuel for the cogeneration unit will come from the existing SPI facilities in California at Arcata, Anderson, Shasta Lake, and Red Bluff, as well as in-forest materials from SPI-owned or controlled timberlands, and various sources of agricultural and urban wood wastes. The available supply from SPI-owned or controlled facilities and timberlands totals 400,000 bone dry tons (BDT) per year. In addition, there are 50,000 BDT of agricultural and urban wood wastes available to SPI annually. The new boiler will consume an average of approximately 25 BDT of biomass fuel per hour which equates to 219,000 BDT per year since it is expected to operate as near to continuously as is practicable.

The Anderson facility currently produces approximately 160,000 BDT of wood wastes per year of which 60,000 BDT are consumed by the existing cogeneration facility, 20,000 BDT are trucked to other biomass power plants, and the balance is trucked to other markets (e.g., wood chips to pulp mills). The new facility will consume a maximum of 219,000 BDT per year, 80,000 BDT of which will be generated by SPI's Anderson facility at a minimum, while the balance (a maximum of 139,000 BDT) will transported by truck from other SPI sources. At a maximum, an additional 23 truck trips per day will be needed to deliver additional fuel to the facility.

The installation of the boiler will not increase emissions from any existing emission units at the Anderson mill. There have been no contemporaneous modifications at the Anderson mill.

2.3 Pollutant Emission Rates

This section addresses pollutant emission rates associated with the project. The proposed boiler will emit NO_X, carbon monoxide (CO), particulate matter smaller than ten microns (PM_{10}), PM, sulfur dioxide (SO_2), and volatile organic compounds (VOCs), as well as several substances identified as TACs by the Air Resources Board (ARB).

2.3.1 Criteria Pollutants

Table 2-1 presents anticipated criteria pollutant emission rates from the cogeneration unit during normal operation. Boiler emission factors for NO_X, CO, PM_{10}, and VOCs were based on the BACT anslysis and expected guarantees from the boiler and control device manufacturers or vendors. The SO_2 emission factor is based on source test information from the existing biomass-fired boiler. Additional material handling operations associated with the project will be enclosed, and, as a result, fugitive dust emissions associated with the project are expected to be negligible.

The cooling tower will emit only PM_{10}. The drift eliminators to be used as part of the cooling tower design (DRU-1.5) will achieve a drift of 0.0005 percent or less. Assuming this drift rate, a water flow rate of 27,600 gallons per minute (gpm), and a conservative total dissolved solids (TDS) value of 725 milligrams per liter (mg/l), the PM_{10} emission rate from the cooling towers is 1.1 ton per year (TPY).

Consistent with the BACT analysis in Appendix B, SPI proposes the following emission limits:

- NO_X – 0.13 lb/MMBtu (30-day average)
- CO – 0.35 lb/MMBtu (3-hour average)
- PM_{10} – 0.02 lb/MMBtu (3-hour average) including filterable and condensable components

SPI does not believe limits are warranted for SO_2 or VOC emissions from the cogeneration unit or for PM_{10} emissions from the cooling tower because the emission rates are so low.

Table 2-2 presents the calculated annual emission increases associated with the project. Table 2-3 presents the maximum hourly and daily emission rates compares them to the AQMD BACT thresholds. Chapter 4 presents dispersion modeling analyses used to assess compliance with ambient air quality standards.

2.3.2 Startup Emissions

SPI typically shuts down its boilers at least twice per year for maintenance. During the subsequent startup, the boiler is heated gradually to avoid stresses that could physically damage the boiler if it were heated too quickly. The startup period may last up to 24 hours when starting with a "cold" (ambient temperature) furnace, and will be accomplished using the natural gas-fired burners firing pipeline natural gas. Firing at full capacity, these burners will provide only thirty percent of rated boiler heat input and will initially be the sole source of heat input to the boiler during startup. Heating will continue using the natural gas burners until the furnace is hot enough to introduce biomass fuel to the furnace. After biomass fuel is introduced to the furnace, the natural gas firing rate will be reduced to maintain a steady heat rate. For the remainder of the startup period, the biomass-fuel feed rate will increase until the desired firing rate is achieved and the natural gas firing is no longer needed. The startup period will end when stable burning of biomass fuel is established under good combustion practices at the desired firing rate and the boiler reaches is design operating temperature.

During the startup period, CO emission rates will exceed those experienced under normal operation. Unlike normal operation, it is very difficult for the boiler manufacturer to estimate startup CO emission rates, which vary continuously during the startup process. Because exhaust levels of oxygen are high and CO_2 levels are low during startup, SPI proposes that the startup CO emission rate limit be a mass-per-unit-time limit rather than a concentration corrected to 12 percent CO_2 as is commonly done for normal operation limits. SPI proposes a startup and shutdown CO emission rate limit of 400 lb/hr averaged over 1 hour.

The natural gas burners are also used during boiler shutdown to burn any remaining wood ash in order to prevent temperature excursions in the ESP. The shutdown process is expected to require up to 24 hours for the furnace to reach ambient temperature, and to experience hourly average CO emission rates similar to those of startup. SPI proposes that the boiler be subject to the startup CO emission rate limits during shutdown.

A modeling analysis was performed to demonstrate that the proposed startup/shutdown emission limits will comply with the CO ambient air quality standards. This analysis is documented in Chapter 4.

2.3.3 Toxic Air Contaminants

Most TAC emission factors for wood-residue fuels were based on source tests used to develop emission factors for AP-42 Section 1.6. However, whereas the USEPA combined all source test data to calculate the AP-42 emission factors regardless of control technology, the emission factors used here were calculated using the subset of source tests in which wood-fired boilers were controlled by ESPs. For the hydrogen chloride (HCl) emission factor, this subset of ESP-controlled source tests was further reduced by removing source tests performed on units burning municipal solid waste. The hexavalent chromium emission factor was calculated using biomass-fired boiler source tests from AP-42 source test data, after excluding source tests that included values based on the detection limit. The ammonia (NH_3) emission rate was based on a maximum exhaust ammonia concentration of 20 parts per million (ppm). Ammonia emissions are a consequence of operating an SNCR system to reduce boiler NO_X emissions to 0.13 lbs/MMBtu.

In cases where no ESP-controlled source test results were available for a particular TAC, results associated with other particulate control equipment were used. Source test data from units not employing particulate controls or not reporting any control equipment were included where no other source test data were available. Table 2-4 presents the TAC emission factors and emission rates associated with the biomass-fired boiler. The cooling tower is not expected to emit any TACs.

3 Regulatory Setting

The proposed biomass-fired cogeneration unit project is subject to federal, state, and local regulations. The following section discusses the applicable regulations and why certain regulatory programs are not applicable. It should be noted that the project will be located in an area that is in attainment of all federal ambient air quality standards, but has been designated as not in attainment with the state ozone and PM_{10} standards.

3.1 Federal Regulations

3.1.1 Prevention of Significant Deterioration

For purposes of new source review, construction of the proposed cogeneration unit is a major modification of an existing major source, and is therefore subject to the requirements of the PSD program because, as shown in Table 2-2, annual CO emissions have the potential to exceed 250 TPY. Table 2-2 also shows that potential NO_X, CO, and PM_{10} emissions exceed the PSD significant emission rates (SERs), indicating that PSD review is required for each of these pollutants.

PSD regulations require a BACT analysis for all air pollutants emitted by a project that exceed the SERs (in this case, NO_X, CO, and PM_{10}). The BACT analysis evaluates the energy, environmental, economic, and other costs associated with each technology, and weighs those costs against the reduced emissions the technology would provide. BACT analyses are presented in Appendix B for the biomass-fired boiler and the cooling tower.

In addition, PSD regulations require modeling analyses to demonstrate compliance with the applicable NAAQS and PSD increments locally, and in national parks and wilderness areas. Evaluations of additional impacts (i.e., growth, visibility, soils, and vegetation) are also required for both local and regional areas. Local and regional air quality modeling, as well as secondary impact, analyses are provided in Chapters 4 and 5, respectively.

3.1.2 Acid Rain Program

The USEPA's Acid Rain Program, Title IV of the Clean Air Act, is intended to achieve significant environmental and public health benefits through reductions in emissions of SO_2 and NO_X, the primary causes of acid rain. The biomass-fired boiler proposed by SPI will not be subject to the requirements of the Acid Rain Program because it is a cogeneration unit with an electrical generating capacity below the program applicability threshold.

40 CFR 72.6 identifies criteria used to determine whether a facility is subject to the Acid Rain Program. Section 72.6(b)(4)(ii) states that a biomass-fired cogeneration unit is not subject to the program if it sells no more than one third of its potential annual electrical output capacity or if it sells less than 219,000 megawatt (electric)-hours (MWe-hrs) of electricity annually. A cogeneration unit meeting either of these criteria is not subject to the Acid Rain Program.

The biomass-fired cogeneration unit proposed by SPI meets the definition of a "cogeneration unit" in 40 CFR 72.2 because at least a portion of the steam generated by the boiler will be delivered first to the steam turbine and then used to heat lumber dry kilns at the existing lumber manufacturing facility. Thus, the steam will be "used twice." Although SPI expects to sell more than one-third of the boiler's annual potential electrical output capacity, the boiler will be an unaffected source because SPI expects to sell no more than 219,000 MWe-hrs of electricity annually. Due to the proposed boiler's cogeneration status and proposed electrical sales, this boiler is considered an unaffected source.

3.1.3 Air Operating Permit Program

The lumber manufacturing facility is a major source subject to the Title V air operating permit program. Because the proposed cogeneration unit is a major modification requiring a PSD permit, a significant permit modification is required under AQMD Rule 5, Section IV.B.3. The cogeneration unit may not commence operation until the permit revision is approved.

3.1.4 New Source Performance Standards

USEPA has established performance standards for a number of air pollution sources in 40 CFR Part 60. These New Source Performance Standards (NSPS) usually represent a minimum level of control that is required of a new source. NSPS Subpart Db addresses emissions from boilers that have a heat input of greater than 100 MMBtu/hr, and will apply to the cogeneration boiler because the maximum annual average heat input is expected to be 425.4 MMBtu/hr.

Subpart Db limits PM emissions to 0.03 lb/MMBtu for newly constructed units. At the proposed maximum firing rate, this limit translates into an emission rate of 43 lb PM/hr. Subpart Db also requires exhaust opacity to be 20 percent or less (6-minute average), except for one 6-minute period per hour, which cannot exceed 27 percent opacity. These standards do not apply during startup, shutdown, or a malfunction. The emission rates proposed by SPI reflect BACT (which is more stringent than these NSPS limits), and the PM_{10} emission rates proposed for the cogeneration unit are less than those allowed by NSPS.

The cogeneration unit will burn natural gas during startup. Subpart Db prescribes SO_2 and NO_X limits on boilers that fire fossil fuels under certain conditions. The SO_2 limits do not apply to boilers that combust natural gas. The NO_X limits in Subpart Db do not apply to boilers that have an annual fossil fuel capacity factor of less than ten percent. SPI will maintain on-site records of the quantities and times that natural gas is fired in the boiler to ensure that gas provides less than 10 percent of the annual fuel input. Consequently, neither the SO_2 nor the NO_X emission limits identified in Subpart Db will apply.

3.1.5 Maximum Achievable Control Technology

The Clean Air Act Amendments of 1990 require USEPA to establish technology-based standards to control hazardous air pollutants (HAPs). For MACT purposes, a major source is defined as one with a potential to emit (PTE) greater than 10 TPY of a single HAP or more than 25 TPY of all HAPs combined.

The existing and proposed boiler would not operate concurrently other than some overlap during startup and shutdown, and the proposed boiler has a greater firing rate, therefore the calculated maximum HAP emissions from the proposed boiler, which is summarized in Table 3-1, represents the maximum annual HAP PTE for any combined operation of the two boilers (i.e., not concurrent operation, but some combination of the two boilers operating during a given 12-month period).

Considering HAP emissions from the proposed boiler and the existing lumber dry kilns,[1] the HAP emitted in greatest quantity will be methanol at an annual rate 9.2 TPY, and emissions of all 47 HAPs combined will be 34.0 TPY. Consequently, the facility's post-project HAP potential to emit will exceed the combined HAPs MACT threshold, and the facility will be subject to the MACT program. It is important to note that we believe the current potential to emit HAPs from the existing boiler and kilns does not exceed the major source thresholds; the potential HAP emissions from the proposed boiler will make the existing facility a major source of HAPs. Per 40 CFR Part 63.9(b)(1)(iii), this permit application serves as the initial notification that, when the proposed cogeneration unit begins operation, the Anderson facility will be a major source of HAPs, and affected emission units will be subject to the requirements of the applicable MACT standards.

3.2 State And Local Emission Regulations

3.2.1 Authority to Construct Permits

Shasta County AQMD Rule 2, Part 100 requires new or modified stationary sources to obtain an ATC air quality permit. The ATC permit application must provide a description of the facility, an inventory of pollutant emissions, and proposed control systems for the applicable pollutants. The reviewing agency considers whether BACT has been employed and evaluates predicted ambient concentrations attributable to these emissions to ensure compliance with ambient air quality standards.

BACT applicability is determined based on daily emission thresholds provided in AQMD Rule 2 Part 301. The daily emissions of each pollutant with the potential for requiring BACT are listed in Table 2-2, along with the daily PTE and regulatory threshold. As shown in the table, BACT is required for reactive organic compounds (ROG), NO_X, SO_2, PM_{10}, CO, and beryllium. BACT analyses are presented in Appendix B for the biomass-fired boiler and the cooling tower.

[1] The lumber dry kilns were estimated to have a maximum annual throughput of 180 million board feet per year (MMbf/yr). This throughput was divided into species-specific annual throughputs (i.e., for ponderosa pine, sugar pine, Douglas fir, and white fir) based on the average throughput fraction of each species using data from 2007 and 2006. The maximum annual species throughputs were combined with emission factors for acetaldehyde, acrolein, formaldehyde, methanol, and propionaldehyde developed by the Oregon Department of Environmental Quality.

As stated in AQMD Rule 2, Part 300, an ATC permit cannot be granted unless the agency determines the project (1) will meet applicable state and federal emission limits; (2) will employ BACT where required; and (3) will not cause or contribute to violations of ambient air quality standards. This application provides the information to enable the AQMD to make those determinations.

3.2.2 District Air Pollution Control Regulations

Regulations addressing emissions of specific air contaminants from a single source are contained in AQMD Rule 3, Part 2. For sources constructed after July 1, 1986, PM emissions are limited to 0.15 grains per dry standard cubic foot (gr/dscf), while PM_{10} is limited to 0.05 gr/dscf, and combustion PM is limited to 0.10 gr/dscf. SO_2 emissions are limited to 200 ppm, and NO_X emissions are limited to 300 ppm for solid fuels, and 250 ppm for gaseous fuels. Opacity is limited to Ringelmann #2 and/or 40 percent.

3.2.3 Air Toxics Hot Spots (AB 2588)

The "Hot Spots" Act, also known as AB 2588 or the Health and Safety Code Section 44300 et seq., requires facilities to which the act applies to inventory and report air toxic emissions from stationary sources. In addition to the TAC emission increases discussed in Section 2.3.3 and summarized in Table 2-4, a Health Risk Assessment of TAC emission increases associated with the proposed project has been provided to AQMD and the Shasta County Planning Department.

3.2.4 California Environmental Quality Act (CEQA)

All ATCs are required to undergo a preliminary review by the AQMD to determine if any possibility of a significant environmental effect exists. Following this review, the AQMD will determine whether further environmental review is required. If further review is warranted, a determination will be made as to whether or not the AQMD is the Lead Agency or a Responsible Agency, and the Environmental Review will proceed as described in AQMD Environmental Review Guidelines (November, 2003).

3.2.5 Offsets

Sections 40918, 40919, 40920, and 40920.5 of the California Health & Saftey (H&S) Code require areas that are designated as being in nonattainment with respect to one or more criteria pollutant State or Federal standards to achieve "no net increase" in emissions (i.e., offsets) of those pollutants and their precursors. Although Shasta County has been designated a nonattainment area with respect to the State ozone and PM_{10} ambient air quality standards, it has further been classified as having "moderate air pollution." Areas that are not classified has having "extreme air pollution" are not required, by H&S Section 40918.5, to implement a no-net-increase permitting program in their attainment plan, and, in 1997, the AQMD repealed Parts 302 and 303 of AQMD Rule 2:1, which had previously implemented such a program. Thus, no offsets are required by the AQMD new source review air permitting program.

4 Air Quality Impacts Analysis

Neither an ATC nor a PSD permit can be issued unless the proposed new source or modification can demonstrate that the allowable emissions will not cause or contribute to violation of any ambient air quality standard or increment. This is typically accomplished using air quality dispersion modeling to predict ambient concentrations. This chapter discusses the methodology used to develop near-field modeling used to predict pollutant concentrations attributable to project emissions in the Class II areas surrounding the proposed facility. Class II areas are essentially the entire country save for areas designated as Class I areas, which are National Parks, Wilderness Areas, and other areas where the smallest PSD increments have been imposed to allow the smallest degree of air quality deterioration. Class II areas have been deemed able to accommodate normal, well-managed industrial growth, and, therefore, have higher PSD increments.[2]

4.1 Model Selection

ENVIRON reviewed regulatory modeling techniques to select the most appropriate air quality dispersion model to simulate dispersion of air pollutants emitted by the proposed project for a near-field air quality impact analysis. The selection of a modeling tool is influenced by the potential for exhaust plumes from point sources to be influenced by nearby on-site structures and to impact complex terrain. The terrain at and immediately surrounding the facility, as well as in the north and east portions of the modeling domain, is relatively flat, however, intermediate and complex terrain exists in the southwest portion of the domain. The heights of proposed and existing structures, and the proposed cogeneration unit stack height, suggests that there is the potential for exhaust plume downwash to occur.

AERMOD is currently the model recommended by the USEPA's Guideline on Air Quality Models (codified as Appendix W to 40 CFR Part 51, hereafter referred to as the Guideline) as the preferred dispersion model for complex source configurations and for sources subject to exhaust plume downwash. AERMOD incorporates numerical plume rise algorithms (called the PRIME algorithm) that include the downwash effects a structure may have on an exhaust plume implicitly. Importantly, the PRIME algorithm also treats the geometry of upwind and downwind structures and their relationship to the emission point more precisely, and is able to calculate concentrations within building cavities.

AERMOD was selected for the modeling analysis primarily because it is the most up-to-date dispersion model currently available. Additionally, the modeling domains and source configurations suggested the potential for exhaust plume downwash and plume impacts on intermediate and complex terrain.

[2] U.S. EPA, *New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting*. Draft. October, 1990.

4.2 Modeling Procedures

AERMOD was applied to both criteria pollutants and TACs using the regulatory defaults in addition to the options and data discussed in this section. Electronic versions of the modeling files are provided on a compact disk in Appendix C.

4.2.1 Model Setup and Application

The most recent version of AERMOD (Version 09292) was applied with the default options for dispersion that depend on local meteorological data, regional upper air data, and the local physical characteristics of land use surrounding the facility. AERMOD contains several options for urban dispersion that were not selected for these analyses. The facility is located near, Anderson, California, and the majority of the study domain is agricultural land, rangeland, or forest. The effects of surface roughness and other physical characteristics associated with the types of land use in the modeling domain were included in the analysis as part of the meteorological database, described in Section 4.4.

4.2.2 Averaging Periods

Criteria and toxic air pollutant concentrations predicted by the model were averaged over short-term (1-, 3-, 8-, and 24-hour) and annual averaging periods as required by the applicable ambient criteria for each modeled pollutant.

4.2.3 Chemical Transformations

Per Section 6.2.3 of the Guideline, ENVIRON assumed that 75 percent of the emitted NO_X is converted to NO_2.

4.3 Elevation Data and Receptor Network

Terrain elevations for receptors and emission sources were prepared using 1/3rd arc-second National Elevation Dataset (NED) data developed by the United States Geological Survey (USGS), and available on the internet from the USGS Seamless Data Server (http://seamless.usgs.gov/index.php). These data have a horizontal spatial resolution of approximately 10 meters (m). Terrain heights surrounding the facility indicate that some of the receptors used in the simulations were located in intermediate or complex terrain (above stack or plume height). The 10-kilometer (km) square simulation domain that was used to assess near-field impacts is shown in Figure 2-2.

Receptors were spaced 500 m apart covering the simulation domain, with 200-m, 50-m, and 25-m spacing receptors grids covering 5-km, 2.5-km, and 1.25-km nested square areas centered on the facility, respectively. Receptors were also located at 25-m intervals along the facility property boundary. The final receptor locations are shown in Figure 4-1.

4.4 Meteorological Data

ENVIRON has conducted a survey of available meteorological data for use in the simulations. A representative data set was prepared using a combination of surface data from meteorological station located at the nearby Redding Municipal Airport, supplemented by National Weather Service (NWS) upper air sounding data from Medford, Oregon.

According to the Guideline, five years of representative meteorological data are considered adequate for dispersion modeling applications. Hourly wind speed, wind direction, temperature, ceiling height, and cloud cover data collected from January 1, 2004 until December 31, 2008 at Redding Municipal Airport were extracted from the National Climatic Data Center's (NCDC's) Integrated Surface Hourly Weather Observations (ISHWO). The airport is located approximately 4.5 kilometers (2.8 miles) north-northwest of the facility. A wind rose describing the wind speed and wind direction data recorded at the Redding Municipal Airport meteorological monitoring station over the entire five-year dataset is shown in Figure 4-2. The wind rose shows that the winds are generally bimodal, with winds generally coming from the north and south, following the broad Sacramento River valley. Upper air radiosonde data for the same period were obtained for the monitoring station at Medford, Oregon, approximately 215 kilometers (134 miles) north of the facility.

The meteorological data were processed using the AERMOD meteorological preprocessor, AERMET (Version 06341). AERMET was used to check parameter ranges, identify missing data, and calculate boundary layer parameters for use by AERMOD. The program replaces missing or out-of-range data with missing value flags, and AERMOD treats these periods as calms. Data recovery across the 5-year surface meteorology dataset was found to be greater than 90 percent for all variables.

Surface parameters including the surface roughness length, albedo, and Bowen ratio were determined for the area surrounding the Redding Municipal Airport meteorological tower using the AERMET preprocessor, AERSURFACE (Version 08009), and the USGS 1992 National Land Cover (NLCD92) land-use data set.[3] The NLCD92 data set used in the analysis has 30 m data point spacing and 21 land-use categories. Seasonal surface parameters were determined using AERSURFACE according to USEPA's guidance.[4]

4.5 Emission Source Release Parameters

Figure 4-3 shows the proposed location of the cogeneration unit stack, as well as significant structures that could potentially influence emissions from the stack. Table 4-1 summarizes the release parameters that were used to represent the cogeneration unit stack and the cooling towers in the simulations.

[3] The USGS NLCD92 data set is described and can be accessed at http://landcover.usgs.gov/natllandcover.php.

[4] The AERMOD Implementation Guide (USEPA, 2008) and the AERSURFACE User's Guide (EPA-454/B-08-001, January 2008).

In addition to the release parameters discussed in the previous section, the building dimensions and facility configuration were provided to AERMOD to assess potential plume downwash effects. Wind-direction-specific building profiles were prepared for the modeling using the USEPA's Building Profile Input Program for the PRIME algorithm (BPIP PRIME). The facility layout and building elevations provided by SPI were used to prepare data for BPIP PRIME, which provides the necessary input data for AERMOD. Figure 4-3 shows the configuration of significant structures, including those of the adjacent lumber manufacturing facility, that were used to develop the BPIP PRIME input files, and Table 4-2 presents the heights of the significant structures included in the simulations.

Based on the site layout shown in Figure 4-3 and the structure heights in Table 4-2, the most significant structure affecting the cogeneration unit stack in the simulations was the boiler building, which is 115 feet (ft), or 32 m, high. For the boiler stack, good engineering practice (GEP) stacks at the same location would have to exceed the maximum creditable GEP height (213 ft or 65 m) to ensure protection against downwash. Therefore, all necessary information provided by BPIP PRIME was included in the simulations to reflect downwash effects from nearby structures on the boiler stack. A similar analysis indicated that emissions from the cooling towers would also be subject to downwash effects, and the appropriate BPIP PRIME output was included in the simulations for that source as well.

4.6 Analysis Results

To evaluate the potential ambient air pollutant concentrations (i.e., impacts on air quality) attributable to the project, the emission rates and source release parameters described in the previous sections were applied in the dispersion modeling analysis. A preliminary analysis included only the emission increase associated with the proposed cogeneration unit and cooling tower, without accounting for the decreased emissions from the existing boiler. Table 4-3 summarizes the predicted maximum concentrations and compares them to both the applicable monitoring de minimis concentrations and the Significant Impact Levels (SILs) established in USEPA's New Source Review Workshop Manual (October 1990). The SILs represent incremental, project-specific impact levels that USEPA generally accepts as insignificant with respect to maintaining compliance with the NAAQS. As shown in Table 4-3, none of the predicted concentrations exceeded the SILs or the monitoring de minimis concentrations. Figures 4-4 through 4-11 show the spatial variations in the maximum predicted criteria pollutant concentrations, averaged over periods consistent with the applicable ambient standards. The maximum predicted receptor and concentration are also shown.

The State of California has not established screening concentrations analogous to the SILs that can be used to determine compliance with the CAAQS without combining the proposed project with background concentrations. Table 4-4 presents predicted criteria pollutant concentrations, combines them with background concentrations and compares the totals with the applicable CAAQS.

4.7 Startup Analysis

AERMOD was applied using the methodology described in the previous sections to demonstrate that the proposed CO startup emission rate will comply with both the one- and eight-hour average ambient CO standards.

Both the forced-air and the induced-draft fans in the boiler will operate throughout the startup process, but the flow will be controlled by dampers to approximately 30 percent of normal operation flow (approximately 62,000 actual cubic feet per minute). This resulted in an exhaust velocity of 20.5 feet per second. The exhaust temperature during startup will be about 250 ºF, approximately 150 ºF cooler than normal operation. These conditions were assumed to be constant throughout the startup process regardless of the fuel mix used after the first two hours of startup.

Assuming an hourly average CO emission rate during startup of 400 lb/hr, the maximum predicted 1-hour and 8-hour average concentrations were 249 and 182 μg/m^3, respectively. To determine compliance with the NAAQS, these results were combined with background values based on the most recent maximum monitored 1-hour and 8-hour average concentrations from the CO monitor in Chico, California[5] The maximum 1-hour and 8-hour average concentrations were 3.1 ppm (approximately 3,550 μg/m^3) and 2.4 ppm (approximately 2,750 μg/m^3), respectively. Because the Anderson area is likely to be less urban than the Chico area, these background values most likely overstate the actual CO concentrations near the facility.

Using the conservative background concentrations described above, the total predicted maximum concentrations (boiler startup emissions plus background) were a 1-hour average of 3,799 μg/m^3, and an 8-hour average of 2,932 μg/m^3. These concentrations are less than the 1-hour and 8-hour average CO CAAQS of 23,000 and 10,000 μg/m^3, respectively (the corresponding NAAQS are 40,000 and 10,000 μg/m^3). Based on this analysis, the proposed hourly CO emission startup limit of 400 lb/hr will not cause of contribute to exceedances of the NAAQS or CAAQS.

4.8 Secondary Impact Analysis

4.8.1 Class II Area Growth

Construction of the proposed cogeneration unit would span between 14 and 18 months. Laydown and temporary worker parking areas will be located within the existing facility property boundary. During construction, approximately 40 temporary works would be added, and local demand for skilled crafts people would increase slightly. However, this demand would be temporary (18 months at most), and mitigated by the use of existing permanent employees where possible (there is an existing on-site fabrication shop). The temporary increases in

[5] Maximum CO concentrations recorded in 2008 by the CO monitor located at 468 Manzantia Ave. in Chico, California; data obtained from EPA's AirData website (http://www.epa.gov/aqspubl1/annual_summary.html)

vehicle miles traveled and vehicular emissions associated with temporary workers would be insignificant. Once the cogeneration unit is operational, SPI expects to employ approximately eight additional workers. SPI does not expect the new cogeneration unit to cause significant population growth in the area nor significant secondary air quality impacts as a result of that growth.

4.8.2 Class II Visibility

On a large spatial scale, visibility is typically evaluated as "regional haze" and is addressed as part of the Class I air quality related values (Section 5). On a local scale, "visibility" is usually evaluated by considering perceptibility of a plume from a stack or cooling tower.

The new biomass-fired cogeneration unit is larger, and will emit air pollutants in larger quantities than the existing boiler. However, the new unit will be of a more modern design than the existing unit, and, as a result, the drift rate from the proposed cooling tower is expected to be significantly more than that of the existing cooling tower.

4.8.3 Soils and Vegetation

Air quality permitting regulations require proponents of major modifications to existing major sources to provide an evaluation of potential impacts to air quality related values. These include impacts to visibility, soils and vegetation. In virtually all cases, the impact analysis for soils and vegetation has focused on impacts to Class I areas. The focus on Class I areas occurs because these areas often include sensitive environments, such as alpine lakes and streams, high-elevation vegetation, and sensitive habitat for threatened or endangered species. Section 5 addresses impacts to soils and vegetation in Class I areas. The potential for such impacts were judged to be unlikely based on screening criteria employed by Federal Land Managers.

For Class II areas, the concern for soil and vegetation impacts is different from Class I areas. Generally, it is not a sensitive habitat that is of concern, but rather the economic well-being of the soils and vegetation for the area. Impacts to agriculture or forestry are the major concerns. There have been instances elsewhere in the U.S. where high levels of sulfur emissions from coal fired power plants, or smelters have caused localized impacts to vegetation and soils near the facility. In fact, the NAAQS were established to protect the public health and welfare, and secondary standards were identified specifically to protect ecological properties such as soils and vegetation.

The Class II air quality assessment results (Section 4.6) indicate that the maximum ambient impacts due to the proposed project will be less than the applicable SILs for both NO_2 and SO_2. Because ambient concentrations attributable to the project would be so low, deposition of nitrogen and sulfur compounds would also be very low.

Typically, to alter the pH of soil, quantities of nitrogen or sulfur on the order of a ton per acre per year would be required; in other words, a considerable amount of nitrogen or sulfur is required to have a significant effect on the pH of the soil. Based on deposition modeling conducted previously for a similar emission unit at this same location, nitrogen and sulfur deposition rates in the vicinity of the facility are typically on the order of ten pounds per acre per year. This very low deposition rate suggests that there would be no acid deposition impacts to commercial farms in the area.

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5 Class I Air Quality Impacts and Air Quality Related Values Analyses

PSD guidance requires analysis of potential impacts to air quality and air quality related values (AQRVs) of concern (i.e., visibility, soil, flora, fauna, and aquatic resources) in Federal Class I areas within 100 km (62.1 miles) of the proposed site from pollutants emitted by the project subject to PSD review. However, for most applications the Federal Land Managers (FLMs) request analyses of AQRV impacts for additional Class I areas within 200 km (124 miles) of the site.

The locations of the proposed project and all nearby Class I areas are shown in Figure 5-1. The Yolla Bolly – Middle Eel Wilderness Area is the Class I area nearest to the Anderson facility, approximately 57 km (35 miles) to the southeast. As shown in Table 5-1, there are four Class I areas within 100 km, and an additional five Class I areas within 200 km.

In June 2008, the Federal Land Managers' Air Quality Related Values Work Group (FLAG) issued a draft revision of the Phase I report that provides guidance and recommendations for how AQRV analyses should be conducted. The draft report describes an initial screening criteria (often referred to as a "Q/D" analysis) that would exempt a source from AQRV impact review based on annual emission rates and distance from a Class I area. Proposed projects with total emission increases of NO_X, SO_2, PM_{10}, and sulfuric acid mist (H_2SO_4), in tons per year (the "Q" in Q/D), which, when divided by the distance to each Class I area, in kilometers (the "D" in Q/D), is 10 or less, would be exempt from AQRV analysis. Although the document containing this screening method is a draft, FLMs have been allowing sources to use it to justify not presenting an AQRV analysis in permit applications.

An AQRV screening analysis was developed for the proposed project using the boiler's expected potential future emissions (Potential to Emit – or "PTE"). As prescribed by the screening methodology, the maximum hourly emission rates for each pollutant required by the screening analysis were converted to tons per year (by multiplying by 8,760 hr/yr and dividing by 2,000 lb/ton) and summed. The closest Class I area is the Yolla Bolly – Middle Eel Wilderness Area, approximately 57 km from SPI's Anderson facility. Table 5-2 summarizes the Q/D analysis; the result is a value of approximately 6, which is less than the FLM-prescribed threshold of 10. As a result, no AQRV analysis is presented. AQRV analysis reviewers at the National Park Service (NPS) and U.S. Forest Service (USFS) were provided with a preliminary Q/D analysis in advance of this permit application, and documentation of their concurrence are presented in Appendix D.

The AQRV screening method outlined above does not have any bearing on the PSD program requirement to assess compliance with the Class I increment for pollutants that increase by more than the PSD significant emission rates (SERs). As shown in Table 2-2, NO_X and PM_{10} exceed the PSD SERs. (The maximum annual CO emission rate also exceeds the PSD SER, but no PSD increments have been established for CO.) However, based on the lack of impacts predicted by the Class I analysis presented in the 2007 permit application in addition to the current Q/D analysis, USEPA has agreed that an updated and revised Class I PSD increment analysis is not necessary in this case, and none is presented.

Tables

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Table 2-1
Proposed Cogeneration Unit Emissions

Pollutant[1]	Emission Factor[1] (lb/MMBtu)	Emission Rate[2]	
		(lb/hr)	(TPY)
NO_x	0.13	60.8	242
CO	0.35	164	652
SO_2	0.005	2.34	9.32
PM_{10}	0.02	9.36	37.3
VOC/ROC	0.017	7.96	31.7
Sulfuric Acid	0.0021	0.986	3.93
Lead	1.19E-05	0.00559	0.0222

1 NO_x, CO, and PM_{10} emission factors are based on BACT and vendor guarantees. The SO_2 emission factor is based on a source test conducted on the existing boiler at the facility. The VOC/ROG emission factor is based on a vendor guarantee. The sulfuric acid (H_2SO_4) emission factor is based on the assumption that sulfate comprises 10.038 percent of PM_{10} emissions, which was obtained from USEPA's SPECIATE 3.2 Profile # 12709 for Hogged Fuel Boiler/Stoker Boiler. The lead emission factor is based on source test data used to develop the emission factor is EPA's AP-42, Section 1.6.

2 Pound per hour emission rate is based on a maximum 1-hour average heat input of 468.0 MMBtu/hr, and the tons per year emission rates is based on an annual average heat input rate of 425.4 MMBtu/hr and continuous operation (8,760 hours per year).

Table 2-2
Project Criteria Pollutant Emissions Increase

Pollutant[1]	Annual Emission Rate[2] (TPY)			PSD SER[3] (TPY)	Over SER?
	Cogen	CT	Total		
NO_x	242	--	242	40	Yes
CO	652	--	652	100	Yes
SO_2	9.32	--	9.32	40	No
$PM_{10}/PM_{2.5}$	37.3	1.10	38.4	15/10	Yes/Yes
VOC/ROG	31.7	--	31.7	40	No
Sulfuric Acid	3.93	--	3.93	7	No
Lead	0.0222	--	0.0222	0.6	No

1 NO_x, CO, PM_{10}, and VOC/ROG emission factors are based on BACT and/or vendor guarantees, while the SO_2 emission factor is based on a source test conducted on the existing boiler at the facility. The sulfuric acid (H_2SO_4) emission factor is based on the assumption that sulfate comprises 10.038 percent of PM_{10} emissions, which was obtained from USEPA's SPECIATE 3.2 Profile # 12709 for Hogged Fuel Boiler/Stoker Boiler.

2 Cogeneration unit annual emission rates based on maximum annual average hourly heat input (425.4 MMBtu/hr). Total proposed = Cogen (cogeneration unit) + CT (cooling tower).

Table 2-3
Project Emission Rates and BACT Thresholds

Pollutant[1]	Hourly Emission Rate[2] (lb/hr)			24-Hr Emission Rate[3] (lb/day)			AQMD BACT Thresh.[4] (lb/day)	Over BACT Thresh?
	Cogen	CT	Total	Cogen	CT	Total		
NO_x	60.8	--	60.8	1,394	--	1,394	25.0	Yes
CO	164	--	164	3,752	--	3,752	500.0	Yes
SO_2	7.49	--	7.49	172	--	172	80.0	Yes
PM/PM_{10}	9.36	0.251	9.61	214	6.02	220	80.0	Yes
VOC/ROG	6.08	--	6.08	139	--	139	25.0	Yes
Sulfuric Acid	0.986	--	0.986	22.6	--	22.6	35.0	No
Lead	0.00559	--	0.00559	0.128	--	0.128	3.2	No
Beryllium	0.000726	--	0.000726	0.0166	--	0.0166	0.002	Yes
Mercury	0.000195	--	0.000195	0.00446	--	0.00446	0.5	No
Vinyl Chloride	0.00861	--	0.00861	0.197	--	0.197	5.0	No

1 NO_x, CO, PM_{10}, and VOC/ROG emission factors are based on vendor guarantees, while the SO_2 emission factor is based on a source test conducted on the existing boiler at the facility. The sulfuric acid (H_2SO_4) emission factor is based on the assumption that sulfate comprises 10.038 percent of PM_{10} emissions, which was obtained from USEPA's SPECIATE 3.2 Profile # 12709 for Hogged Fuel Boiler/Stoker Boiler. Lead, beryllium, mercury, and vinyl chloride emission factors were based on the source test data used to develop the emission factors in AP-42 Section 1.6.

2 Cogeneration unit hourly emission rates are based on a maximum hourly heat input of 468.0 MMBtu/hr

3 Cogeneration unit hourly emission rates are based on a maximum 24-hour average heat input of 446.7 MMBtu/hr

4 From Sierra County AQMD Rule 2:1, Part 301.

Table 2-4
Cogeneration Unit Toxic Air Contaminant Emission Rates

Compound	CAS No.	Emission Factor (lb/MMBtu)	Emission Rate		
			(lb/hr)[1]	(lb/day)[2]	(lb/yr)[3]
Acenaphthene	83-32-9	7.25E-09	0.00000339	0.0000777	0.027
Acenaphthylene	208-96-8	1.54E-06	0.000719	0.0165	5.73
Acetaldehyde	75-07-0	1.99E-04	0.093	2.13	741
Acetone	67-64-1	1.62E-04	0.0758	1.74	604
Acetophenone	98-86-2	3.23E-09	0.00000151	0.0000346	0.012
Acrolein	107-02-8	3.15E-05	0.0148	0.338	118
Ammonia[4]	7664-41-7	2.02E-02	9.46	217	75,300
Anthracene	120-12-7	4.95E-08	0.0000232	0.000531	0.185
Antimony	7440-36-0	4.61E-07	0.000215	0.00494	1.72
Arsenic	7440-38-2	4.94E-07	0.000231	0.0053	1.84
Barium	7440-39-3	1.52E-04	0.0711	1.63	567
Benzaldehyde	100-52-7	8.45E-07	0.000395	0.00906	3.15
Benzene	71-43-2	8.61E-04	0.403	9.23	3,210
Benzo(a)anthracene	56-55-3	2.52E-09	0.00000118	0.000027	0.00938
Benzo(a)pyrene	50-32-8	3.27E-09	0.00000153	0.0000351	0.0122
Benzo(b)fluoranthene	205-99-2	2.35E-09	0.0000011	0.0000252	0.00876
Benzo(e)pyrene	192-97-2	2.59E-09	0.00000121	0.0000278	0.00966
Benzo(g,h,i)perylene	191-24-2	4.62E-09	0.00000216	0.0000496	0.0172
Benzo(j)fluoranthene	205-82-3	1.56E-07	0.0000728	0.00167	0.58
Benzo(k)fluoranthene	207-08-9	2.38E-09	0.00000111	0.0000255	0.00888
Benzoic Acid	65-85-0	4.68E-08	0.0000219	0.000502	0.174
Beryllium	7440-41-7	1.55E-06	0.000726	0.0166	5.78
Bis(2-ethylhexyl)phthalate	117-81-7	4.65E-08	0.0000218	0.000499	0.173
Bromomethane	74-83-9	2.80E-05	0.0131	0.3	104
2-Butanone (MEK)	78-93-3	5.39E-06	0.00252	0.0578	20.1
Cadmium	7440-43-9	2.59E-06	0.00121	0.0278	9.65
Carbazole	86-74-8	1.79E-06	0.000838	0.0192	6.67
Carbon Dioxide (CO_2)[5]	37210-16-5	2.07E+02	96800	2,220,000	771,000,000
Carbon Tetrachloride	56-23-5	4.54E-05	0.0212	0.487	169
Chlorine	7782-50-5	7.92E-04	0.371	8.49	2,950

Compound	CAS No.	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)[1]	(lb/day)[2]	(lb/yr)[3]
Chlorobenzene	108-90-7	3.32E-05	0.0155	0.356	124
Chloroform	67-66-3	2.75E-05	0.0129	0.295	103
Chloromethane	74-87-3	2.31E-05	0.0108	0.248	86.1
2-Chloronaphthalene	91-58-7	2.41E-09	0.00000113	0.0000258	0.00896
2-Chlorophenol	108-43-0	3.37E-08	0.0000158	0.000362	0.126
Chromium, hexavalent[4]	18540-29-9	1.75E-07	0.000082	0.00188	0.653
Chromium, trivalent	7440-47-3	1.24E-06	0.000582	0.0133	4.63
Chrysene	218-01-9	2.75E-09	0.00000129	0.0000295	0.0103
Cobalt	7440-48-4	8.93E-06	0.00418	0.0958	33.3
Copper	7440-50-8	4.11E-06	0.00192	0.044	15.3
Crotonaldehyde	4170-30-3	9.91E-06	0.00464	0.106	36.9
Decachlorobiphenyl	2051-24-3	2.65E-10	0.000000124	0.00000284	0.000988
Dibenzo(a,h)anthracene	53-70-3	2.35E-09	0.0000011	0.0000252	0.00875
1,2-Dibromoethene	106-93-4	5.48E-05	0.0256	0.587	204
Dichlorobiphenyl	2050-68-2	3.79E-10	0.000000177	0.00000406	0.00141
1,2-Dichloroethane	107-06-2	2.92E-05	0.0137	0.313	109
Dichloromethane	75-09-2	2.87E-04	0.134	3.08	1,070
1,2-Dichloropropane	78-87-5	3.33E-05	0.0156	0.357	124
2,4-Dinitrophenol	51-28-5	9.33E-08	0.0000436	0.001	0.348
Ethylbenzene	100-41-4	3.13E-05	0.0146	0.336	117
Fluoranthene	206-44-0	5.17E-07	0.000242	0.00554	1.93
Fluorene	86-73-7	5.31E-08	0.0000248	0.000569	0.198
Formaldehyde	50-00-0	1.96E-03	0.917	21	7,300
Heptachlorobiphenyl	28655-71-2	6.57E-11	3.07E-08	0.000000704	0.000245
Hexachlorobiphenyl	26601-64-9	2.89E-10	0.000000135	0.0000031	0.00108
HpCDD-Total	37871-00-4	3.09E-11	1.44E-08	0.000000331	0.000115
HpCDF-Total	38998-75-3	6.40E-12	2.99E-09	6.86E-08	0.0000238
HxCDD-Total	34465-46-8	8.55E-11	0.00000004	0.000000917	0.000319
HxCDF-Total	55684-94-1	1.53E-11	7.18E-09	0.000000164	0.0000571
Hexanal	66-25-1	6.96E-06	0.00326	0.0746	25.9
Hydrogen chloride	7647-01-0	3.52E-03	1.65	37.8	13,100
Indeno(1,2,3-c,d)pyrene	193-39-5	2.37E-09	0.00000111	0.0000255	0.00885

Compound	CAS No.	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)[1]	(lb/day)[2]	(lb/yr)[3]
Iron	7439-89-6	9.93E-04	0.465	10.6	3,700
Isobutyraldehyde	78-84-2	1.15E-05	0.00538	0.123	42.9
Lead	7439-92-1	1.19E-05	0.00559	0.128	44.5
Manganese	7439-96-5	1.16E-04	0.0541	1.24	431
Mercury	7439-97-6	4.16E-07	0.000195	0.00446	1.55
Methane[5]	74-82-8	7.05E-02	33	756	263,000
Methanol[6]	67-56-1	8.30E-04	0.388	8.9	3,090
2-Methylnaphthalene	91-57-6	2.75E-07	0.000129	0.00295	1.02
Molybdenum	7439-98-7	1.13E-06	0.000526	0.0121	4.19
Monochlorobiphenyl	2051-60-7	2.18E-10	0.000000102	0.00000234	0.000812
Naphthalene	91-20-3	8.51E-05	0.0398	0.913	317
Nickel	7440-02-0	2.84E-06	0.00133	0.0304	10.6
Nitric Oxide (NO)[7]	10102-43-9	1.30E-01	60.8	1390	484,000
2-Nitrophenol	88-75-5	1.06E-07	0.0000497	0.00114	0.396
4-Nitrophenol	100-02-7	1.71E-07	0.0000801	0.00184	0.638
Nitrous Oxide (N_2O)[5]	10024-97-2	9.26E-03	4.33	99.3	34,500
OCDD	3268-87-9	2.34E-10	0.000000109	0.00000251	0.000871
OCDF	39001-02-0	1.43E-11	6.67E-09	0.000000153	0.0000531
PeCDD-Total	36088-22-9	1.72E-10	8.03E-08	0.00000184	0.000639
PeCDF-Total	30402-15-4	4.19E-11	1.96E-08	0.000000449	0.000156
Pentachlorobiphenyl	25429-29-2	6.49E-10	0.000000304	0.00000696	0.00242
Pentachlorophenol	87-86-5	2.27E-08	0.0000106	0.000243	0.0846
Perylene	198-55-0	5.18E-10	0.000000242	0.00000555	0.00193
Phenanthrene	86-01-8	1.69E-06	0.000793	0.0182	6.32
Phenol	108-95-2	1.25E-05	0.00587	0.134	46.7
Phosphorus	7723-14-0	3.54E-05	0.0166	0.38	132
Potassium	7440-09-7	3.88E-02	18.2	416	145,000
Propionaldehyde	123-38-6	3.15E-06	0.00147	0.0338	11.7
Pyrene	129-00-0	2.99E-07	0.00014	0.00321	1.11
Selenium	7782-49-2	3.38E-06	0.00158	0.0363	12.6
Sodium	7440-23-5	3.63E-04	0.17	3.89	1,350
Strontium	7440-24-6	1.01E-05	0.00471	0.108	37.5

Compound	CAS No.	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)[1]	(lb/day)[2]	(lb/yr)[3]
Sulfuric Acid[7]	7664-93-9	2.11E-03	0.986	22.6	7,860
TCDD-Total	1746-01-6	2.05E-10	9.57E-08	0.00000219	0.000762
TCDF-Total	30402-14-3	1.63E-10	0.000000076	0.00000174	0.000606
Tetrachlorobiphenyl	26914-33-0	1.60E-09	0.000000749	0.0000172	0.00596
Tetrachloroethene	127-18-4	3.82E-05	0.0179	0.41	142
Tin	7440-31-5	3.91E-05	0.0183	0.419	146
Titanium	7440-32-6	2.01E-05	0.00941	0.215	74.9
o-Tolualdehyde	529-20-4	7.15E-06	0.00335	0.0767	26.6
p-Tolualdehyde	104-87-0	1.13E-05	0.00529	0.121	42.1
Toluene	108-88-3	2.13E-05	0.00994	0.228	79.2
Trichlorobiphenyl	15862-07-4	1.78E-09	0.000000833	0.0000191	0.00663
1,1,1-Trichloroethane	71-55-6	3.07E-05	0.0144	0.329	115
Trichloroethene	79-01-6	3.03E-05	0.0142	0.325	113
Trichlorofluoromethane	75-69-4	4.05E-05	0.019	0.434	151
2,4,6-Trichlorophenol	88-06-2	1.14E-08	0.00000531	0.000122	0.0423
Vanadium	1314-62-1	5.94E-07	0.000278	0.00637	2.21
Vinyl Chloride	75-01-4	1.84E-05	0.00861	0.197	68.6
Xylene	1330-20-7	2.45E-05	0.0115	0.262	91.2
Yttrium	7440-65-5	3.01E-07	0.000141	0.00323	1.12
Zinc	7440-66-6	1.74E-04	0.0814	1.86	648

1 Based on a maximum hourly heat input rate of 468.0 MMBtu/hr.

2 Based on a maximum daily average heat input rate of 446.7 MMBtu/hr and continuous 24-hour operation.

3 Based on an annual average heat input rate of 425.4 MMBtu/hr and 8,760 hours of operation per year.

4 Based on 20 ppm exhaust concentration

5 CO_2, CH_4, and N_2O emission factors taken from 40 CFR 98, Subpart C, Table C-1.

6 Methanol emission factor for wood-fired boilers from NCASI Technical Bulletin No. 858 (February 2003).

7 100 percent of NO_X was assumed be NO, which is conservative because 75 percent of NO_X was assumed to be converted to NO_2.

Table 3-1
Hazardous Air Pollutant Emission Rates

Compound	CAS No.	Emission Rate[1]	Compound	CAS No.	Emission Rate[1]
Acetaldehyde[2]	75-07-0	9.05	Formaldehyde[2]	50-00-0	3.857
Acetophenone	98-86-2	6.01E-06	Hydrogen chloride	7647-01-0	6.57
Acrolein[2]	107-02-8	0.178	Lead	7439-92-1	0.0222
Antimony	7440-36-0	0.000858	Manganese	7439-96-5	0.215
Arsenic	7440-38-2	0.000920	Mercury	7439-97-6	0.000775
Benzene	71-43-2	1.60	Methanol[2]	67-56-1	9.20
Beryllium	7440-41-7	0.00289	Naphthalene	91-20-3	0.159
Bis(2-ethylhexyl)phthalate	117-81-7	8.66E-05	Nickel	7440-02-0	0.00529
Bromomethane	74-83-9	0.0522	4-Nitrophenol	100-02-7	0.000319
2-Butanone (MEK)	78-93-3	0.0100	Pentachlorophenol	87-86-5	4.23E-05
Cadmium	7440-43-9	0.00483	Phenol	108-95-2	0.101
Carbon Tetrachloride	56-23-5	0.0846	Phosphorus	7723-14-0	0.0660
Chlorine	7782-50-5	1.48	Propionaldehyde[2]	123-38-6	0.00587
Chlorobenzene	108-90-7	0.0619	Selenium	7782-49-2	0.00630
Chloroform	67-66-3	0.0513	TCDD-Total	1746-01-6	3.81E-07
Chloromethane	74-87-3	0.0430	Tetrachloroethene	127-18-4	0.0712
Chromium, trivalent	7440-47-3	0.00232	Toluene	108-88-3	0.0396
Cobalt	7440-48-4	0.0166	1,1,1-Trichloroethane	71-55-6	0.0573
1,2-Dibromoethene	106-93-4	0.102	Trichloroethene	79-01-6	0.0565
1,2-Dichloroethane	107-06-2	0.0544	2,4,6-Trichlorophenol	88-06-2	2.11E-05
Dichloromethane	75-09-2	0.539	Vinyl Chloride	75-01-4	0.0343
1,2-Dichloropropane	78-87-5	0.0620	Xylene	1330-20-7	0.0456
2,4-Dinitrophenol	51-28-5	0.000174	Total HAPs		34.0
Ethylbenzene	100-41-4	0.0583	Maximum Ind. HAP		9.20

1 All emission rates in tons per year (tpy).

2 Cogeneration unit and lumber dry kiln emission rates combined.

Table 4-1
Point Source Release Parameters

Source	Height (ft)	Diameter (ft)	Exit Velocity (ft/s)	Temperature (°F)
Proposed Cogeneration Unit	115	8.0	68.4	400
Cooling Tower (each of 2 cells)	41	31.6	24.2	91

Table 4-2
Structure Heights

Structure	Height (feet)	Height (meters)
Truck Shop	16	4.88
Equipment Shop	27	8.23
Fabrication Shop	43	13.11
Warehouse	32	9.75
Dry Shed	52	15.85
Planer	60	18.29
Kilns	24	7.32
Existing Cooling Tower	30	9.14
Diesel Fuel	16	4.88
Forestry Lab	29	8.84
Lumber Storage Shed	26	7.92
Existing Boiler	43	13.11
Sawmill	54	16.46
Chipper/Hog	29	8.84
Fuel House	52	15.85
Turbine	40	12.19
Proposed Cooling Tower	30	9.14
Proposed Boiler	115	35.05
Proposed Economizer	50	15.24
ESP	50	15.24
Truck Shop	16	4.88

Table 4-3
Criteria Pollutant NAAQS Compliance Assessment

Pollutant	Averaging Period	Maximum Predicted[1]	SIL[1,2]	Over SIL?	Monitoring de Minimis[1,3]	Over de Minimis?
NO_2[4]	1-Hour	12.3	--	--	--	--
	Annual	0.906	1	No	14	No
CO	1-Hour	86.3	2,000	No	--	--
	8-Hour	63.0	500	No	575	No
PM_{10}	24-Hour	1.43	5	No	10	No
	Annual	0.213	1	No	--	--
$PM_{2.5}$[5]	24-Hour	1.43	--	--	--	--
	Annual	0.213	--	--	--	--
SO_2	3-Hour	2.04	25	No	--	--
	24-Hour	1.09	5	No	13	No
	Annual	0.149	1	No	--	--

1 Concentrations are in micrograms per cubic meter (µg/m^3)

2 SIL = Significant Impact Level, from USEPA's New Source Review Workshop Manual (October, 1990), Table C-4.

3 Monitoring de Minimis concentrations from 40 CFR 52.21(i)(8)(i).

4 NO_2 was assumed to be 75 percent of the emitted NO_X based on guidance in Section 6.2.3 of the USEPA's Guideline on Air Quality Models (codified as Appendix W to 40 CFR Part 51). The 1-hour average NO_2 concentration shown is the maximum 8th-highest daily 1-hour maximum concentration averaged across the five modeled years. SILs and monitoring de minimis concentrations have not yet been established for NO_2. A NAAQS compliance assessment was performed by combining the modeled NO_2 concentration with a background concentration. Because 3-year average of the 98th percentile of the annual distribution of the daily maximum 1-hour average NO_2 concentrations are not yet available for recent ambient monitoring data to use as a background concentration, the maximum 1-hour average NO_2 concentration from the monitor at 468 Manzanita Ave in Chico, California was used as a background, which is a conservative approach. Adding the modeled concentration (12.3 µg/m^3) to the background (80.9 µg/m^3) gives a total concentration of 93.2 µg/m^3, which is less than the applicable NAAQS (188 µg/m^3).

5 SILs and monitoring de minimis concentrations have not yet been established for $PM_{2.5}$. A NAAQS compliance assessment was performed by combining the modeled $PM_{2.5}$ concentrations (which assume that all PM_{10} is $PM_{2.5}$) with the most recent maximum concentrations from the monitor on the roof of the Redding Department of Health (24-hour average – 20.2 µg/m^3, and annual average – 5.49 µg/m^3), gives total concentrations of 21.7 µg/m^3 (24-hour average) and 5.73 µg/m^3 (annual average), which are less than the applicable NAAQS (24-hour average – 35 µg/m^3, and annual average – 15 µg/m^3).

Table 4-4
Criteria Pollutant CAAQS Compliance Assessment

Pollutant	Averaging Period	Maximum Predicted[1]	Background[2]	Total[3]	CAAQS	Over CAAQS?
NO_2[4]	1-Hour	14.0	80.9	94.9	339	No
	Annual	0.906	15.0	15.1	57	No
CO	1-Hour	86.3	3,550	3,636	23,000	No
	8-Hour	63.0	2,750	2,813	10,000	No
PM_{10}	24-Hour	1.43	37.0	38.4	50	No
	Annual	0.213	18.2	18.4	20	No
$PM_{2.5}$[5]	Annual	0.213	5.49	5.70	12	No
SO_2	1-Hour	2.30	7.85	10.1	655	No
	24-Hour	1.09	5.23	6.32	105	No

1 Concentrations are in micrograms per cubic meter (μg/m^3)

2 Background concentrations are the most recent maximum monitored concentrations (with exceptional event data removed, where applicable) from the following stations and years:

NO_2 & CO: Chico – Manzanita Ave; 2008

PM_{10}: Anderson – North Street; 2009

$PM_{2.5}$: Redding – Health Department Roof; 2009

SO_2: North Highlands – Blackfoot Way; 2009

Monitoring data are from EPA's AirData website (http://www.epa.gov/aqspubl1/annual_summary.html)

3 Total = Maximum Predicted + Background

4 NO_2 was assumed to be 75 percent of the emitted NO_X based on guidance in Section 6.2.3 of the USEPA's Guideline on Air Quality Models (codified as Appendix W to 40 CFR Part 51).

5 All PM_{10} was assumed to be $PM_{2.5}$

Table 5-1
Distances from Proposed Project to Nearby Class I Areas

Class I Area	Distance (km)
Caribou Wilderness Area	89
Lassen Volcanic National Park	64
Lava Beds National Monument	148
Marble Mountain Wilderness Area	116
Redwood National Park	147
South Warner Wilderness Area	192
Thousand Lakes Wilderness Area	62
Yolla Bolly-Middle Eel Wilderness Area	57

Table 5-2
Summary of Q/D Analysis

Parameter	Value[1]	Units
Project NO_X Emission Increase	254	tpy
Project SO_2 Emission Increase	9.78	tpy
Project PM_{10} Emission Increase	39.1	tpy
Project H_2SO_4 Emission Increase	4.12	tpy
Total Project Emission Increase	307	tpy
Distance to Closest Class I Area	57	km
Q/D	5.39	tpy/km
Q/D Threshold of Concern	10	tpy/km

1 Emission rate increases are based on maximum 24-hour average emission rates.

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Figures

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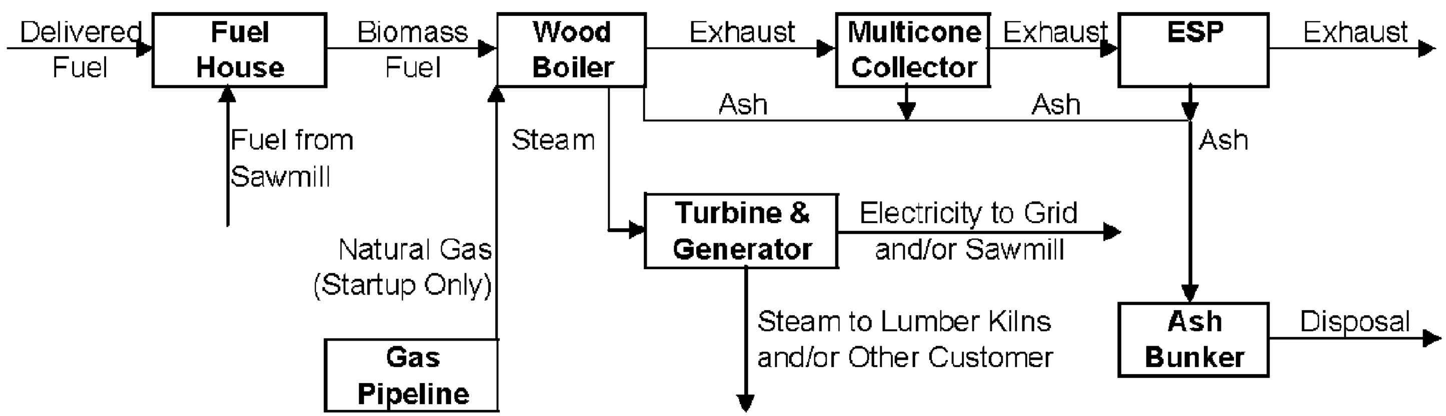

Figure 2-1. Project Schematic Flow Diagram