U.S. ENVIRONMENTAL PROTECTION AGENCY
REGION IX

SUPPLEMENTAL STATEMENT OF BASIS AND AMBIENT AIR QUALITY IMPACT REPORT FOR GREENHOUSE GAS EMISSIONS

For a Clean Air Act
Prevention of Significant Deterioration Permit

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

November 2013

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Proposed Prevention of Significant Deterioration Permit

SUPPLEMENTAL STATEMENT OF BASIS AND AMBIENT AIR QUALITY IMPACT REPORT FOR GREENHOUSE GAS EMISSIONS

Sierra Pacific Industries – Anderson Division
(PSD Permit SAC 12-01)

Table of Contents

Acronyms & Abbreviations

AAQIR	Ambient Air Quality Impact Report
Act	Clean Air Act [42 U.S.C. Section 7401 et seq.]
Agency	U.S. Environmental protection Agency
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.]
CCS	Carbon Capture and Storage (or Sequestration)
CFR	Code of Federal Regulations
CH_4	Methane
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalents
CO	Carbon Monoxide
CBI	Confidential Business Information
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental protection Agency
ESA	Endangered Species Act
Facility	Sierra Pacific Industries – Anderson Division
FLM	Federal Land Manager
FR	Federal Register
FWS	U.S. Fish and Wildlife Service
GEP	Good Engineering Practice
GHG	Greenhouse Gases
hp	Horsepower
HRSG	Heat Recovery Steam Generator
kW	kilowatt
lbs	Pounds
lb CO_2e/lb steam	Pounds of CO_2 Equivalents per Pound of Steam
lb CO_2e/MW-hr	Pounds of CO_2 Equivalents per Megawatt-hour
m	meter
MMBtu	Million British Thermal Units
MMBtu/hr	Million British Thermal Units per Hour
MW	Megawatts of electrical power
NAAQS	National Ambient Air Quality Standards
NO	Nitrogen oxide or nitric oxide
NO_2	Nitrogen Dioxide
N_2O	Nitrous Oxide
NO_x	Oxides of Nitrogen ($NO + NO_2$)
NSCR	Non-Selective Catalytic Reduction

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
RATA	Relative Accuracy Test Audit
RBLC	U.S. EPA RACT/BACT/LAER Information Clearinghouse
SCAQMD	Shasta County Air Quality Management District
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SPI	Sierra Pacific Industries
tpy	Tons per Year

Proposed Prevention of Significant Deterioration (PSD) Permit

SUPPLEMENTAL STATEMENT OF BASIS AND AMBIENT AIR QUALITY IMPACT REPORT FOR GREENHOUSE GAS EMISSIONS

SPI-ANDERSON

Executive Summary

Sierra Pacific Industries-Anderson Division (SPI or SPI-Anderson) 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 periods of startup, shutdown and flame stabilization. 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). EPA has previously determined that the proposed major Prevention of Significant Deterioration (PSD) permit modification is consistent with the requirements of the PSD program for nitrogen oxides (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 ($PM_{2.5}$). We are making a further determination that the proposed PSD permit modification is consistent with the requirements of the PSD program for greenhouse gas emissions (GHGs) for the following reasons:

- The proposed PSD permit requires the Best Available Control Technology (BACT) for greenhouse gases (GHG) emissions, to the greatest extent feasible. There are no National Ambient Air Quality Standards (NAAQS) for GHGs.

- 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) due to GHG emissions.

- 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 effect due to GHG emissions 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 is a Supplemental Statement of Basis and Ambient Air Quality Impact Report (AAQIR) related to greenhouse gas emissions (GHG) for the proposed PSD permit modification for the SPI-Anderson facility. This document supplements our Statement of Basis and Ambient Air Quality Impact Report dated September 2012, which covers non-GHG emissions -- specifically, NO_x, CO, PM, PM_{10} and $PM_{2.5}$. (*See* online docket #III.02, *SPI-Anderson Ambient Air Quality Impact Report_12SEP12*.) This Supplemental AAQIR describes the legal and factual basis for the best available control technology determination for GHG emissions for the proposed PSD permit modification, including requirements under the PSD regulations at Title 40 of the Code of Federal Regulations (CFR) §52.21. This Supplemental AAQIR also serves as the supplemental fact sheet to meet the requirements of 40 CFR Part 124.7 and 124.8.

2. Introduction

EPA previously issued a final permit decision regarding this project on February 19, 2013 (February 2013 Permit). The February 2013 Permit required use of BACT to limit emissions of NO_x, CO, PM, PM_{10} and $PM_{2.5}$, to the greatest extent feasible. EPA also determined that air pollution emissions from the new cogeneration unit and ancillary equipment 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. Ms. Celeste Draisner, Mr. Rob Simpson, Ms. Heidi Strand, and Mr. Ed W. Coleman (Petitioners) each petitioned the Environmental Appeals Board (EAB or Board) to review the Final Permit.

On July 18, 2013, the EAB denied review on all but one of the challenges raised by the Petitioners, finding that the Region clearly erred in failing to hold a public hearing. *In re Sierra Pacific Industries*, PSD Appeal Nos. 13-01 through 13-04 (EAB July 18, 2013), E.A.D. 15 _____. The EAB's decision requires the Region to reopen the permit proceedings and issue a final permit decision and a document that responds to any new comments received during the public hearing.

In addition, on July 12, 2013, the United States Court of Appeals for the District of Columbia Circuit vacated EPA's rule[1] deferring regulation of biogenic carbon dioxide (CO_2) emissions from PSD review. *Ctr. for Biological Diversity v. EPA*, 722 F.3d 401 ((D.C. Cir. 2013). EPA Region 9 relied on the Deferral Rule in issuing the February 2013 Permit, and so did not make BACT determinations or include permit conditions regulating GHG emissions in the February 2013 Permit. The EAB stated in its July 18, 2013 decision that it was declining to address the challenge to the Region's reliance on the Deferral Rule. The EAB stated that it expects that the

[1] *Deferral for CO_2 Emissions from Bioenergy and Other Biogenic Sources Under the Prevention of Significant Deterioration (PSD) and Title V Programs (*Deferral Rule), 76 Fed. Reg. 43490, 43493 (July 20, 2011).

Region will consider this challenge in light of the decisions the Agency makes regarding the Court's ruling on the Deferral Rule.

EPA has not made any decisions at this time with respect to application of PSD permitting requirements after the Court's opinion on the Deferral Rule. Due to its grant of an earlier extension request, the D.C. Circuit has not yet issued the mandate in its decision on the biogenic CO_2 deferral rule, and the decision remains subject to possible additional legal proceedings. On October 22, 2013, the intervenors in *Center for Biological Diversity* filed a second request to extend the deadline for petitions for rehearing. To facilitate EPA action on this permit while these matters remain unresolved, SPI submitted to EPA PSD application material for GHG emissions from the proposed new equipment. SPI requested that EPA review such materials and include appropriate emission limits and related requirements in the proposed permit modification. The proposed permit modification that EPA Region 9 is announcing today is similar to the proposed permit modification that we announced in September 2012; however, it now includes GHG emission limits and related requirements.[2] The remainder of this document provides the EPA's analysis of the GHG BACT determination for the proposed project.

3. GHG Emissions from the Proposed Project

EPA's PSD permitting regulations define GHGs as an aggregate of: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). 40 CFR § 52.21(b)(49)(i). The proposed project has the potential to emit only three of these GHGs: CO_2, CH_4, and N_2O. All GHG emissions associated with the project will be generated by the cogeneration unit and emergency engine; the cooling tower will not emit any GHGs.

EPA regulations further define CO_2e as the sum of the mass emissions of the constituent GHG, each multiplied by the appropriate global warming potential (GWP) factor provided in Table A-1 of the Federal Mandatory GHG Reporting Rule (see 40 CFR Part 98). 40 CFR § 52.21(b)(49)(ii).

3.1 Proposed New Equipment

Table 3-1 lists the proposed new equipment that will be regulated by the PSD permit, and the existing equipment currently located at the SPI-Anderson facility.

[2] We are also using this opportunity to revise certain other conditions (primarily related to monitoring, performance testing, and recordkeeping) to address minor technical issues we identified since February 2013. These revisions do not affect our BACT determinations for non-GHG pollutants and do not require revision to the September 2012 AAQIR.

Table 3-1: New and Existing Equipment List

Type	Unit	Description
Proposed New Equipment	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.
Existing Equipment	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
	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
	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) 200hp, 59,000CFM Rader blower
	7 De-greasing Tanks	• Non-solvent based tanks
	Gasoline Storage Tank	• Above ground with 10,000 gallon capacity tank
	Painting Operation	• Miscellaneous painting operation
	Drying Kilns	• (8) steam-heated, double-track, lumber drying kilns

The proposed biomass boiler of the cogeneration unit is expected to have a maximum annual average heat input of 468 million British thermal units per hour (MMBtu/hr), and an annual average heat input of 425 MMBtu/hr. The biomass boiler will also be equipped with two 62.5 MMBtu/hr natural gas burners that will be used during startup, and, potentially, during shutdown and for flame stabilization. The biomass boiler will combust a small amount of natural gas throughout the year, but the vast majority of emissions will be from combustion of wood and wood-residual solid biomass fuel.

The proposed emergency engine will be natural-gas-fired, and will operate as a feedwater pump used to circulate water through the cogeneration unit boiler in case of an emergency shutdown while disconnected from the grid. The emergency engine will have a maximum heat input of 2.16 MMBtu/hr, and will be operated a maximum of 100 hours per year for maintenance and testing purposes, in addition to any emergency use.

Tables 3-2 and 3-3 summarize the GHG emissions for the biomass boiler and emergency engine, and total CO_2e emissions from the project, and show that the proposed project has the potential to generate a maximum of 432,439 tons of CO_2e per year. SPI's GHG emission estimates for the proposed boiler are slightly different because values were rounded up, providing a total potential of 433,000 tons of CO_2e per year.

Table 3-2: Greenhouse Gas Emissions for Proposed New Equipment

Emission Unit	GHG Pollutants	Emission Factor[3] (Heat Input)		Global Warming Potential[4]	GHG Pollutant Emission Rate (tpy)[5]	CO_2e Emission Rate (tpy)
		(kg/MMBtu)	(lb/MMBtu)			
Stoker Boiler	CO_2	93.8	206.60793	1	423,513	423,513
	CH_4	0.032	0.07048	21	144	3,034
	N_2O	0.0042	0.00925	310	19	5,879
	Total CO_2e	--	--	--	--	432,426
Emergency Engine	CO_2	53.02	116.78411	1	13	13
	CH_4	0.001	0.00220	21	0.00024	0[6]
	N_2O	0.0001	0.00022	310	0.00002	0[7]
	Total CO_2e	--	--	--	--	13

(Source: Table 2-1 of Biomass-Fired Cogeneration Project: Best Available Control Technology Analysis for Greenhouse Gases, Sierra Pacific Industries Lumber Manufacturing Facility Anderson, California, August 15, 2013)

[3] The kg/MMBtu emission factors for combustion of wood and wood residual solid biomass fuel, and natural gas, are from 40 CFR Part 98, Tables C-1 and C-2; the lb/MMBtu emission factors are calculated by converting the kg/MMBtu emission factors using 2.2046 lb/kg.
[4] 100-year time horizon global warming potential (GWP – from 40 CFR Part 98, Table A-1).
[5] Calculated by multiplying the emission factor by the maximum annual average heat input (468 MMBtu/hr for the cogeneration unit and 2.16 MMBtu/hr for the emergency pump engine). Annual emission rates are based on 8,760 hr/yr operation for the cogeneration unit, and 100 hr/yr for the emergency pump engine. CO2e was calculated by multiplying each individual emission rate by the applicable GWP factor, and summing.
[6] CO_2e estimate for CH_4 is less than 1 tpy.
[7] CO_2e estimate for N_2O is less than 1 tpy.

Table 3-3: Total Greenhouse Gas Emissions for New Equipment

GHG Pollutants	CO_2e Emission Rate (tpy)
CO_2	423,526
CH_4	3,034
N_2O	5,879
Total	432,439

(Source: Table 2-3 of Biomass-Fired Cogeneration Project: Best Available Control Technology Analysis for Greenhouse Gases, Sierra Pacific Industries Lumber Manufacturing Facility Anderson, California, August 15, 2013)

The PSD permit limits the annual heat input from natural gas to not exceed 10 percent of the total heat input on an annual basis. Operation of the natural gas burners will not exceed 10 percent of the annual heat input capacity of the boiler, or 409,934 MMBtu/yr (468 MMBtu/hr * 8.760 hr/yr * 10%). Based on that maximum annual heat input and the CO_2e emission factor for natural gas combustion from 40 CFR Part 98 (117 lb/MMBtu), the maximum GHG emissions from the natural gas burners will be 23,981 tpy.

The proposed cogeneration unit will be started and shutdown as infrequently as possible. SPI anticipates at least one outage period each year for maintenance; any additional shutdown-and-startup cycles will be the result of an unscheduled event. It will take approximately 12 hours to start the cogeneration unit; natural gas burners will be used to heat the refractory for the first 6 hours, and then biomass fuel will be phased in and gas firing phased out over the final 6 hours. Shutdown will take approximately 1 hour to accomplish, and the natural gas burners will be used only if elevated carbon monoxide (CO) levels are indicated by the continuous emissions monitoring system (CEMS). Based on the startup protocol outlined above, a calculated estimate of GHG emissions is provided in Tables 3-4 and 3-5.

Table 3-4: Greenhouse Gas Emissions for Startup Periods

Fuel	GHG Pollutants	Emission Factor[8] (lb/MMBtu)	Hourly Emission Rate[9] (lb/hr)	Event Emission Rate[10] (lb/event)
Firing Biomass Fuel	CO_2	207	96,770	580,622
	CH_4	0.282	132	792
	N_2O	0.03702	17	104
	Total CO_2e	--	104,916	629,498
Firing Natural Gas	CO_2	117	14,611	87,666
	CH_4	0.0022	0.276	1.65
	N_2O	0.00022	0.0276	0.165
	Total CO_2e		14,625	87,752

(Source: Table 2-2 of Biomass-Fired Cogeneration Project: Best Available Control Technology Analysis for Greenhouse Gases, Sierra Pacific Industries Lumber Manufacturing Facility Anderson, California, August 15, 2013)

Table 3-5: Total Greenhouse Gas Emissions for Startup Periods

GHG Pollutants	Average Hourly Emission Rate (lb/hr)	Event Emission Rate (lb/event)	Event Emission Rate (ton/event)
CO_2	55,691	668,288	334
CH_4	66	794	0.397
N_2O	9	104	0.0521
Total CO_2e	59,771	717,250	359

(Source: Table 2-2 of Biomass-Fired Cogeneration Project: Best Available Control Technology Analysis for Greenhouse Gases, Sierra Pacific Industries Lumber Manufacturing Facility Anderson, California, August 15, 2013)

3.2 Existing Equipment

Existing equipment at the facility includes a biomass-fired boiler with a maximum annual average heat input capacity of 116.5 MMBtu/hr, and a circuit breaker and two switches that utilize sulfur hexafluoride (SF_6) as a dielectric medium. The existing boiler will be decommissioned and dismantled after the new cogeneration unit is constructed and operating. The existing circuit breaker will be used by the new equipment and will not be modified. There are also eight steam-heated, double-track, kilns used for drying lumber at the facility. No combustion occurs in the kilns; thus, no GHGs are emitted from the kilns. Tables 3-6 and 3-7 summarize the GHG emission rate calculations for the existing equipment at the facility.

[8] The CH_4 and N_2O emission rates were increased by a factor of 4 to reflect incomplete combustion during startup; a similar approach was taken when calculating CO and VOC emission rates during startup.
[9] Hourly emission rates are based on 468 MMBtu/hr when firing biomass, and 125 MMBtu/hr when firing natural gas.
[10] Event emission rate is the hourly emission rate multiplied by 6 hours.

Table 3-6: Greenhouse Gas Emissions for Existing Equipment

Emission Unit	GHG Pollutants	Emission Factor[11] (Heat Input) (kg/MMBtu)	Emission Factor[11] (Heat Input) (lb/MMBtu)	Global Warming Potential	GHG Pollutant Emission Rate (tpy)	CO_2e Emission Rate[12] (tpy)
Boiler	CO_2	93.8	206.60793	1	105,335	105,335
	CH_4	0.032	0.07048	21	35.9	755
	N_2O	0.0042	0.00925	310	4.7	1,462
	Total CO_2e	--	--	--	--	107,552
Circuit Breaker	SF_6	1% leakage/year		23,900	0.000950	5
	Total CO_2e	--	--	--	--	5

(Source: Table 2-3 of Biomass-Fired Cogeneration Project: Best Available Control Technology Analysis for Greenhouse Gases, Sierra Pacific Industries Lumber Manufacturing Facility Anderson, California, August 15, 2013)

Table 3-7: Total Greenhouse Gas Emissions for Existing Equipment

GHG Pollutants	CO_2e Emission Rate (tpy)
CO_2	105,335
CH_4	755
N_2O	1,462
SF_6	5
Total CO_2e	107,557

(Source: Table 2-3 of Biomass-Fired Cogeneration Project: Best Available Control Technology Analysis for Greenhouse Gases, Sierra Pacific Industries Lumber Manufacturing Facility Anderson, California, August 15, 2013)

4. Applicability of the Prevention of Significant Deterioration Regulations

This section describes the pollutants covered by the PSD permitting program. Under the Clean Air Act, EPA has set federal National Ambient Air Quality Standards, or NAAQS, for six common air pollutants. These commonly found air pollutants are known as “criteria pollutants” and are found all over the United States. They are particulate matter ($PM_{2.5}$ and PM_{10}), ground-

[11] The kg/MMBtu emission factors for combustion of wood and wood residual solid biomass fuel, and natural gas, are from 40 CFR Part 98, Tables C-1 and C-2; the lb/MMBtu emission factors are calculated by converting the kg/MMBtu emission factors using 2.2046 lb/kg.

[12] The emission rate for the existing biomass-fired boiler was calculated by multiplying the emission factor by the maximum heat input (116.4 MMBtu/hr); annual emission rates are based on 8,760 hr/yr operation. The annual SF_6 emission rate for the switchgear was calculated by multiplying the SF_6 capacity of the existing breaker and two switches (190 lb) by the annual leak rate of (1%, which was the industry standard at the time the equipment was installed); the hourly emission rate was based on the assumption that the leak rate is uniform throughput the year. CO_2e was calculated by multiplying each individual emission rate by the applicable GWP factor, and summing.

level ozone, carbon monoxide, sulfur oxides, nitrogen oxides, and lead. EPA has established maximum concentrations, called NAAQS, for each criteria pollutant above which adverse effects on human health may occur. Areas that meet the NAAQS are classified as being in "attainment" of the standards. Areas that do not meet the NAAQS are classified as being "nonattainment." A single area can be attainment for some criteria pollutants and nonattainment for others.

The PSD permitting program applies to any new major stationary source and any major modification of an existing major stationary source located in an area that is designated as in attainment or unclassifiable with a NAAQS. The PSD regulations at 40 CFR § 52.21 define a "major stationary source" as any source type belonging to a list of 28 source categories which emits or has the potential to emit 100 tons per year (tpy) or more of any regulated New Source Review (NSR) pollutant, or any other source type which emits or has the potential to emit such pollutants in amounts equal to or greater than 250 tpy.

The PSD regulations defines a "major modification" as a physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase of a regulated NSR pollutant, and a significant net emissions increase of that pollutant from the major stationary source. In general, a regulated NSR pollutant includes any pollutant for which a NAAQS has been promulgated, and also includes GHG emissions, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, reduced sulfur compounds, municipal waste combustor organics, municipal waste combustor metals, municipal waste combustor acid gases, and municipal solid waste landfill emissions. EPA previously addressed all of these pollutants, except for GHG emissions, as part of our February 2013 permit action. (*See* online docket #III.02, *SPI-Anderson Ambient Air Quality Impact Report_12SEP12* at pp. 8-9.) Therefore, this Supplemental AAQIR addresses GHG emissions from the project.

On January 2, 2011, GHGs became a pollutant that is "subject to regulation" under the PSD permitting program of the CAA. For PSD purposes, GHG is a single air pollutant defined as the aggregate of six gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride (SF_6). EPA's Tailoring Rule (75 Federal Register 31514, June 3, 2010) established initial GHG applicability thresholds for new sources or modifications, which phase in over time. The Tailoring Rule does not change the basic PSD applicability process for evaluating whether there is a new major source or modification. However, the process for determining whether a source is emitting GHGs in an amount that would make the GHGs a regulated NSR pollutant, includes a calculation of, and applicability threshold for, the source based on CO_2 equivalent (CO_2e) emissions as well as its GHG mass emissions. A source's CO_2e emissions are computed by multiplying the mass amount of emissions in tons per year (tpy) for each of the six GHGs by the gas's associated global warming potential published at Table A-1 of 40 CFR part 98, subpart A.

Given that SPI-Anderson is an existing major stationary source under the PSD permitting program, and the proposed project is a major modification for non-GHG pollutants, the "subject to regulation" threshold for GHGs is 75,000 tpy CO_2e. See 40 CFR § 52.21(b)(49)(iv)(*b*). The data in Table 4-1 show that, when CO_2 emissions from the combustion of biomass are included, the proposed project will be subject to PSD review for GHGs.

Table 4-1: Estimated Emissions and PSD Applicability

Estimated Annual GHG Emissions from Project (tpy of CO_2e)	Significant Threshold for GHGs (tpy mass)	"Subject to Regulation" Threshold for Modification at an Existing Source (tpy of CO_2e)	Does PSD Apply?
432,439	0	75,000	Yes

In general, the PSD permitting program requires, among other things, the installation of BACT, air quality modeling and ambient monitoring, and public involvement. However, since there are no NAAQS or PSD increments for GHGs, the requirements to demonstrate that a source does not cause or contribute to a violation of the NAAQS is not applicable to GHGs. Thus, we do not recommend that PSD applicants be required to model or conduct ambient monitoring for CO_2 or GHGs. Ambient air quality monitoring for GHGs is not required because EPA regulations provide an exemption in sections 40 CFR 52.21(i)(5)(iii) and 51.166(i)(5)(iii) for pollutants that are not listed in the appropriate section of the regulations, and GHGs are not currently included in that list. Furthermore, EPA believes it is not necessary to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations. (*See* online docket #I.64, *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) at pp. 47-48).

EPA is currently the PSD permitting authority, and, thus, is responsible for issuing PSD permits for air pollution sources located within the jurisdiction of the Shasta County Air Quality Management District.

5. Best Available Control Technology

This chapter describes the Best Available Control Technology (BACT) for the control of GHG 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."

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 first outlined the process it still uses today to do this case-by-case analysis (referred to as "top-down" BACT analysis) in a June 13, 1989 memorandum. Further elaboration on EPA's recommended approach was reflect in the 1990 NSR Workshop Manual. The top-down BACT analysis is a well established procedure that the EPA has followed in its permitting decisions and that the EAB has consistently considered 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 involves ranking available control technologies 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 GHG emissions for the new proposed emission units. Table 5-1 lists the BACT determinations for GHG emissions from the proposed boiler and emergency engine. The cooling tower is not expected to produce GHG emissions.

Table 5-1: Summary of GHG BACT Requirements

Unit	Emission Limits	Operational Restrictions	Testing, Monitoring, Reporting, and Recordkeeping Requirements
Stoker Boiler (468 MMBtu/hr)	• 0.36 lb CO_2e per lb steam • 12-month rolling average basis	• Combust biomass fuel • Combust natural gas during startup and shutdown periods, and for flame stabilization only • Boiler design, good combustion practices, and efficient operation	• CO_2 CEMS • Continuously monitor steam production rate • Annual CO_2 performance testing • Record efficiency of boiler on a daily basis
Emergency Engine (256 hp)	--	NSPS Subpart JJJJ compliant engine	NSPS Subpart JJJJ compliant engine

5.1 GHG BACT for a New Biomass Boiler at a Lumber Facility

The SPI-Anderson facility will install and operate a new boiler to support lumber operations at the sawmill operation and to sell electricity to the grid. The new boiler will have a maximum heat input capacity of 468 MMBtu/hr, and an annual average heat input of 425 MMBtu/hr. The boiler is subject to BACT for GHG emissions. A top-down BACT analysis for this pollutant has been performed and is summarized below.

5.1.1 Step 1 – Identify Available Control Technologies

SPI-Anderson identified the control alternatives in Table 5-2 for the proposed biomass boiler.

Table 5-2: GHG Control Alternatives

GHG Pollutant	Add-on Control Options	Inherently Lower-Emitting Control Options	Other Control Options
CO_2	• Carbon capture and sequestration	• Good boiler design, good combustion practices, and efficient operation	• Utilization of biomass fuel alone • Boiler design alternatives (i.e, stoker- including vibrating, traveling grate, etc.; fluidized bed- including pressurized or atmospheric, such as bubbling bed, circulating, etc.)
CH_4	• Activated carbon adsorption systems • Thermal destruction • Catalytic destruction	• Proper combustion practices and use of a properly designed boiler	--
N_2O	• Non-selective catalytic reduction (NSCR) • Thermal destruction • Catalytic destruction	• Proper combustion practices and use of a properly designed boiler	• Removal of SCR and SNCR control systems to reduce N_2O emissions • Addition of N_2O-Abating SCR System

5.1.2 Step 2 – Eliminate Technically Infeasible Control Technologies

CO_2 Control Options

<u>*Boiler Design Alternatives*</u>
EPA evaluated boiler design alternatives in the AAQIR for the proposed permit issued for public comment in September 2012. EPA determined that a fluidized bed boiler is not technically feasible. (*See* online docket #III.02, *SPI-Anderson Ambient Air Quality Impact Report_12SEP12* at pp. 12-13). Since that time, EPA became aware of New Source Review PSD air permits issued for two similar biomass-fired cogeneration projects that propose to use a fluidized bed boiler. These projects are North Springfield Sustainable Energy Project in Vermont and WE Energies in Wisconsin. SPI provided EPA addition information in a September 13, 2013 submittal that distinguished its Anderson facility's operations from those of North Springfield Sustainable Energy Project and WE Energies. (*See* online docket #I.54, *SPI-Anderson Info Response to EPA 13SEP2013*).

North Springfield Sustainable Energy Project would recover low grade heat to produce hot water for a thermal loop in the North Springfield Industrial Park. The North Springfield Industrial Park typically has existing means for generating hot water, and the proposed thermal loop would augment the existing system. Thus, the consequences associated with the "low grade heat" from the North Springfield Energy Project being unavailable to the North Springfield Industrial Park hot water system would be limited to a return to the current hot water system status. SPI will not have a similar operational setup. The North Springfield Energy Project does not operate lumber dry kilns, or provide process steam of any real consequence, and is not subject to operational considerations regarding influences on steam load demand external to power production as with the SPI-Anderson facility.

The WE Energies project would include an 800 MMBtu/hr biomass-fired circulating fluidized bed boiler and a 350 MMBtu/hr natural gas-fired package boiler. Steam from the biomass-fired boiler will be used to generate electricity, and to provide process steam to the Domtar Mill. During periods when the biomass-fired boiler is not available, the natural gas-fired package boiler will be used to provide process steam to the Domtar Mill, allowing the Mill to continue operation. Again, SPI will not have a similar operational setup. SPI has not proposed installing and operating a similar additional fossil-fuel based boiler. In addition, SPI will shut down and decommission the existing 116.4 MMBtu/hr biomass boiler after the new cogeneration unit is operational; thus, the existing biomass-fired boiler at the SPI-Anderson facility will no longer operate and is expected to be decommissioned after the new cogeneration unit is operational.

SPI also provided additional information from fluidized bed boiler manufacturers which indicate a fluidized bed boiler design would not be appropriate for the proposed cogeneration project at the SPI-Anderson facility. According to this information, operation of the fluidized bed boiler would be unstable at 60 to 70 percent turndown.[13] The instability would lead to insufficient mixing in the bed and hot spots. This would further lead to associated problems such as higher quantities of ash in the bed which form deposits around heat transfer media in the bed. These ash and ash-coated particles contain sodium and potassium compounds which react to lower the eutectic point of the particles thereby causing them to agglomerate or sinter to become larger particles or "rocks." These particles can stick to the boiler refractory and may damage the refractory wall. This process can lead to bed de-fluidization, and the boiler would have to be shut down to remove these materials.

SPI has determined that it would be impractical to employ a fluidized bed boiler that lacked a 20 to 50 percent turndown capability. When operational, the proposed cogeneration unit will be the only source of steam at the SPI-Anderson facility. It will provide steam to the turbine to generate electricity, and to the kilns to produce dried lumber. If the biomass cogeneration unit is incapable of operating at low loads (i.e., 20 to 50 percent of full load), the kilns would have to cease operation any time the power production demand by Pacific Gas and Electric (PG&E) decreased significantly, or the turbine was not operating.

[13] Turndown mode is, generally, when the boiler is operating at less than its nominal rated capacity (i.e., less than 100 percent load).

For the reasons stated above, EPA agrees that a fluidized bed boiler is not technically feasible for the SPI-Anderson facility.

Utilization of Biomass Fuel Alone
This control option consists of combustion of biomass fuels, alone or in combination with other fuels, in boilers to generate steam at the SPI-Anderson facility. Since biomass is the primary fuel that will be used at the facility, this control option is technically feasible.

Good Boiler Design, Good Combustion Practices, and Efficient Operation
This control option consists of: (1) altering the combustion process to reduce CO_2 emissions; and (2) maximizing the heat transfer efficiency of the boiler and the mechanical efficiency of the steam turbine and generator, which minimizes the quantity of fuel combusted and, therefore, the quantity of CO_2 generated per unit of steam or electricity generated. According to SPI, at maximum operation, the efficiency of the proposed boiler (i.e., the fraction of the energy in the fuel that is transferred to the steam) is expected to be approximately 70 percent. The efficiency of the electrical generator is, at full load, approximately 96 percent. The overall efficiency of the cogeneration unit will vary depending upon the quantities of steam used to heat the kilns and generate electricity, but is expected to vary between 37 and 53 percent. This control option is technically feasible.

Carbon Capture and Sequestration (CCS)
This control option consists of removing CO_2 from the post-combustion exhaust stream. Following capture, the CO_2 would be transported and stored permanently, or "sequestered," in a geologic formation. Potential CO_2 sequestration sites include geological formations (including oil and gas fields for enhanced recovery) and ocean storage. SPI-Anderson identified three approaches to CO_2 capture that are generally applicable to power generation: (1) pre-combustion systems designed to separate CO_2 and hydrogen (H_2) from produced syngas, (2) post-combustion systems designed to separate CO_2 from flue gas, and (3) oxy-combustion that uses high-purity oxygen (O_2) instead of air, which produces flue gas composed largely of CO_2. Use of a pre-combustion system would require a gasification unit to produce syngas from the biomass fuel, which would amount to redefining the source. Oxy-combustion of biomass fuels is typically in the context of being co-fired with coal, a fossil fuel which will not be used at the facility. Therefore, SPI determined that post-combustion CCS is the only technical feasible control option that will be considered for application on the proposed biomass-fired boiler.

CH_4 Control Options

Proper Combustion Practices and Use of a Properly Designed Boiler
CH_4 emissions are generally the result of incomplete fuel combustion. In the case of biomass, volatile compounds (including CH_4) are released as the fuel is heated in the furnace, some portion of which escapes combustion by improper mixing with oxygen or being confined to zones of relatively low temperature. Proper combustion practices and use of a properly designed boiler maximizes complete combustion, which minimizes formation of CH_4. This control option is technically feasible.

Activated Carbon Adsorption Systems

Adsorption systems pass the gas stream though canisters filled with activated carbon, and the CH_4 is trapped in pores located on the carbon particles. When the carbon approaches saturation, the canister is replaced and processed to remove the CH_4, which is recovered or destroyed. Adsorption systems are usually limited to sources generating organic compounds having a molecular weight of more than 50 and less than approximately 200. Low molecular weight organics, such as CH_4 which has a molecular weight of 16, usually do not adsorb sufficiently. (*See* online docket #I.65, *EPA Activated Carbon Adsorber Website 27SEPT2013*). In addition, the CH_4 concentration in the cogeneration unit exhaust stream will be very small (i.e., less than 1 percent by volume). For these reasons, using adsorption technology to reduce CH_4 emissions from a biomass-fired boiler in not considered technically feasible.

Thermal Destruction Systems

Oxidation systems increase the temperature of the gas stream until the CH_4 oxidizes, forming CO_2 and water. Thermal oxidizers destroy CH_4 using a flame. To thermally oxidize a pollutant in an exhaust stream, a combustor is located in the exhaust duct, and fuel (typically natural gas) and enough supplemental air to support a flame are introduced. While the thermal oxidizer may destroy a portion of the small amount of CH_4 present in the exhaust (i.e., less than 1 percent by volume), the oxidizer itself is likely to generate additional air pollutants (e.g., NO_x, CO, VOCs, and CH_4) such that there is a net increase in emissions. In addition, a thermal oxidizer has never been used to reduce CH_4 emissions from a biomass-fired boiler. SPI has determined that control of CH_4 using thermal oxidation is considered speculative and not achieved in practice for a biomass-fired boiler, and, therefore, not technically feasible for reducing CH_4 emissions from a biomass-fired boiler.

Catalytic Destruction Systems

Oxidation systems increase the temperature of the gas stream until the CH_4 oxidizes, forming CO_2 and water. Thermal oxidizers destroy volatile compounds using a flame, while catalytic oxidation uses a catalyst to promote the oxidation reaction at a temperature lower than the combustion temperature of volatile compounds such as CH_4. Regardless of whether the catalyst is located upstream or downstream of a particulate control device (e.g., an electrostatic precipitator), alkali compounds in the exhaust gas deactivate the catalyst. To counteract the deactivation, large quantities of catalyst must be deployed and frequently replaced, resulting in unpredictable boiler availability and control system costs. However, SPI-Anderson determined that a catalytic oxidation system to reduce CH_4 emissions from the proposed biomass-fired boiler is technically feasible.

N_2O Control Options

Proper Combustion Practices and Use of a Properly Designed Boiler

Typically, furnace conditions that favor CH_4 formation, also favor N_2O formation. N_2O is the result of lower combustion temperatures (less than 800°C or 1,475°F). Its formation can be limited to some extent by using proper combustion techniques and a properly designed boiler that promotes uniform furnace temperatures. This control option is technically feasible.

Non-Selective Catalytic Reduction

NSCR systems are typically used to reduce emissions from reciprocating engines operated in a rich-burn or stoichiometric mode. In general, NSCR systems pass the exhaust gases over catalysts, which use metals (e.g., platinum, rhodium, palladium) to convert NO_x, carbon monoxide (CO), and volatile organic compounds (VOCs) to water, nitrogen, and CO_2. NSCR systems have primarily been developed to reduce N_2O emissions from adipic and nitric acid production operations. There are no instances of an NSCR system being applied to reduce N_2O emissions from a biomass-fired boiler. Because significant differences exist between the exhaust from adipic and nitric acid operations and that of a biomass-fired boiler (i.e., typical N_2O concentration in exhaust from a nitric acid plant is typically over 1,000 ppm, while the concentration in biomass-fired boiler exhaust is approximately 10 ppm), it is not clear that the technology could be transferred effectively, and is therefore considered technically infeasible for control of N_2O from proposed biomass-fired boiler.

Thermal Destruction Systems

Thermal destruction of N_2O is achieved using a reducing flame burner combusting premixed methane or natural gas. The flame temperature must be maintained high enough to destroy the N_2O, but below 1,500°C to minimize NO_x formation. To thermally oxidize a pollutant in an exhaust stream, a combustor is located in the exhaust duct, and fuel (typically natural gas) and enough supplemental air to support a flame are introduced. A thermal oxidizer may destroy a small amount of N_2O present in the exhaust (i.e., less than 1 percent by volume); however, the oxidizer itself is likely to generate additional air pollutants (e.g., NO_x, CO, VOCs, and CH_4) such that there is a net increase in emissions. In addition, a thermal oxidizer has never been used to reduce CH_4 emissions from a biomass-fired boiler. SPI determined that a thermal oxidizer is not achieved in practice for a biomass-fired boiler, and, therefore, not technically feasible for reducing N_2O emissions from a biomass-fired boiler.

Catalytic Destruction Systems

Catalytic destruction is accomplished at lower temperatures (400°C to 700°C) using metal- or zeolite-based N_2O-decomposing catalysts. As previously mentioned above, this control is considered technically feasible.

Removal of SCR and SNCR Control Systems to Reduce N_2O Emissions

Conventional commercially-available selective catalytic reduction (SCR) systems (i.e., those using titanium, tungsten, and vanadium-based catalysts) used to reduce emissions of nitric oxide (NO) and nitrogen dioxide (NO_2), as well as selective non-catalytic reduction (SNCR) systems, generate N_2O, so removal of such control systems would reduce N_2O emissions. Since no SCR system is proposed for installation on the proposed biomass-fired boiler, it is technically infeasible to not install such a system. An SNCR system is proposed by SPI to reduce NO_x emissions from the biomass-fired boiler. It is technically feasible to not install such a system.

Addition of N_2O-Abating SCR System

The criteria pollutant BACT analysis provided with the PSD permit application concluded that conventional SCR systems were technically feasible for reducing NO_X emissions from biomass-fired boiler; therefore, N_2O-abating SCR systems are also considered technically feasible.

5.1.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

After elimination of technically infeasible control options, the remaining control methods are provided as follows.

Post-Combustion CCS

Currently available technology can theoretically capture approximately 90 percent of the post-combustion CO_2 in flue gas. It is not expected to impact CH_4 or N_2O in the exhaust. Table 5-3 shows estimates for the potential GHG emission reductions resulting from the use of post combustion CCS technology of 88.1 percent on a CO_2e basis. SPI estimated a potential GHG emission reduction level of approximately 83 percent which considers GHG emission increases as a result of the additional capacity needed to power the CCS systems, and which would degrade the net GHG reduction. However, SPI did not provide specific information on GHG emissions for this additional capacity. Therefore, our analysis includes the estimate of 88.1 percent.

Table 5-3: Post Combustion CCS

GHG	Emission Rate (tpy)	GWP	Uncontrolled CO_2e (tpy)	% Control	Controlled CO_2e (tpy)
CO_2	423,513	1	423,513	90	381,162
CH_4	144	21	3,034	0	0
N_2O	19	310	5,879	0	0
Total	--	--	432,426	--	381,162
				Percent GHG Reduction:	88.1%

Catalytic Destruction/Oxidation of CH_4 and N_2O

Table 5-4 shows SPI's estimates for the potential GHG emission reductions resulting from the use of oxidation catalyst technology. This technology would result in a reduction of 1.6 percent on a CO_2e basis.

Table 5-4: Catalytic Destruction/Oxidation

GHG	Emission Rate (tpy)	GWP	Uncontrolled CO_2e (tpy)	% Control	Controlled CO_2e (tpy)
CO_2	423,513	1	423,513	0	0
CH_4	144	21	3,034	40	1,214
N_2O	19	310	5,879	95	5,585
Total	--	--	432,426	--	6,798
				Percent GHG Reduction:	1.6%

Removal of NO_x Control System (SNCR)

SPI estimated that SNCR systems convert, depending upon the reagent and furnace conditions, between 10 and 20 percent of NO_x in the exhaust to N_2O. SPI estimated that the proposed biomass boiler would have a PTE of 267 tpy for NO_x. Assuming up to 20 percent of the NO_x in the exhaust is converted to N_2O results in a conservative estimate of 53.4 tpy of N_2O emissions. SNCR systems do not generate any CO_2 or CH_4, so elimination of the system would not affect concentrations of these compounds in the exhaust gas. Table 5-5 shows the estimated potential GHG emission reduction resulting from removal of the SNCR control system. The reduction in GHG emissions would be 3.7 percent on a CO_2e basis. EPA notes that this is a very conservative estimate.

Table 5-5: Removal of SNCR System

GHG	Emission Rate (tpy)	GWP	Uncontrolled CO_2e (tpy)	% Control	Controlled CO_2e (tpy)
CO_2	423,513	1	423,513	0	0
CH_4	144	21	3,034	0	0
N_2O (combustion)	19	310	5,879	0	0
N_2O (SNCR control)	53.4	310	16,554	100	16,554
Total	--	--	448,980	--	16,554
				Percent GHG Reduction:	3.7%

Addition of N_2O-Abating SCR System

Addition of a N_2O-abating SCR system would capture all N_2O emissions generated in the combustion process by the boiler. Table 5-6 shows the estimated potential GHG emission reductions resulting from the addition of a N_2O-abating SCR system. The reduction in GHG emissions would be 1.4 percent on a CO_2e basis. EPA notes that this is a very conservative estimate.

Table 5-6: Addition of N_2O-Abating SCR System

GHG	Emission Rate (tpy)	GWP	Uncontrolled CO_2e (tpy)	% Control	Controlled CO_2e (tpy)
CO_2	423,513	1	423,513	0	0
CH_4	144	21	3,034	0	0
N_2O	19	310	5,879	100	5,879
Total	--	--	432,426	--	5,879
				Percent GHG Reduction:	1.4%

<u>Good Boiler Design, Good Combustion Practices, and Efficient Operation / Proper Combustion Practices and Use of a Properly Designed Boiler / Utilization of Biomass Fuel Alone</u>

SPI proposed to operate the proposed project in a manner that minimizes emissions of all pollutants, and maximizes the energy derived from the fuel consumed. In addition, biomass is the primary fuel combusted in the boiler during all modes of operation. SPI uses natural gas during startup and shutdown periods, and periods in which flame stabilization is needed. SPI expects approximately 75 percent of that fuel to be comprised of sawmill residues from the SPI-Anderson sawmill and the nearby Shasta Lake sawmill. The remaining 25 percent is expected to be a combination of in-forest residues, agricultural residues from orchards in the Sacramento Valley, and urban wood residues diverted from landfills. These measures, in combination, are considered the baseline from which all other alternatives will be evaluated. All other control alternatives would be applied in addition to these measures.

Table 5-7 provides the ranking of the technically feasible control alternatives, in order of most to least effective on a CO_2e basis, based on the above control evaluations.

Table 5-7: GHG Control Methods Ranked by Control Effectiveness

Control Method	**Effectiveness**
Post Combustion CCS	88.1 percent reduction on a CO_2e basis
Removal of NO_x Control System (SNCR)	3.7 percent reduction on a CO_2e basis
Catalytic Destruction	1.6 percent reduction on a CO_2e basis
Addition of N_2O-Abating SCR System	1.4 percent reduction on a CO_2e basis
Good Boiler Design, Good Combustion Practices, and Efficient Operation / Proper Combustion Practices and Use of a Properly Designed Boiler / Utilization of Biomass Fuel Alone	Baseline

Table 5-8 provides recent GHG BACT determinations made at similar facilities according to the RACT/BACT/LAER Clearinghouse (RBLC), as well as other permit determinations not included in the RBLC. SPI proposed a GHG limit of 0.36 lb CO_2e per lb steam produced based on a 12-month rolling block average.

Table 5-8: Summary of Recent GHG BACT Determinations for Similar Biomass Boilers[14]

Facility	State	Permit Issuance Date	Size (MMBtu/hr)	Control Methods	CO_2e Emission Limits	Averaging Period	Source
North Springfield Sustainable Energy Project	VT	4/19/2013	464	• Energy efficiency design/ measures • Good operating and maintenance practices	• 2,668 lb/MW-hr (first 2 years of operation) ; • 2,675 lb/MW-hr (starting the 3rd year of operation)	12-month rolling avg	RBLC # *VT-0039
Beaver Wood Energy Fair Haven LLC	VT	2/10/2012	482	• Energy efficiency design/ measures • Good operating and maintenance practices	• 2,993 lb/MW-hr	30-day rolling avg	RBLC # VT-0037
Abengoa Bioenergy Biomass of Kansas LLC	KS	9/16/2011 (Effective date)	22 MW	• Energy efficiency design/ measures • Good operating and maintenance practices	• 0.34 lb/lb of steam produced	30-day rolling avg	Final PSD Permit
WE Energies (Rothschild facility)	WI	3/28/2011 (Revised 4/4/2013 & 5/21/2013)	800	• Energy efficiency design/ measures • Good operating and maintenance practices	• 3,120 lb/MW-hr	12-month rolling avg	Final PSD Permit
Montville Power LLC	CT	4/6/2010 (Revised 5/20/2013)	600	• Energy efficiency design/ measures • Good operating and maintenance practices	• 590,103 tpy; • 15,564 BTU/kW-hr	12-month rolling avg	RBLC # CT-0156

5.1.4 Step 4 – Evaluate Most Effective Controls

In our evaluation of the most effective controls, we review the economic, environmental, and energy impacts for control methods under consideration. The economic impact analysis is used to quantify the cost of control. Usually, if the cost of reducing emissions, as expressed in dollars per ton of pollutant removed ($/ton), is on the same order as the cost previously borne by other sources of the same type in applying the control alternative, then the control alternative is considered economically feasible, and therefore acceptable as BACT.

Post Combustion CCS

CCS systems require additional energy to remove CO_2 from the boiler exhaust, as well as to compress it for transport and storage. The relatively dilutee concentration of CO_2 in the exhaust gas of a biomass boiler (i.e., between 10 and 20 percent by weight) would require a strong solvent to capture the CO_2, as well as a considerable amount of energy to regenerate the solvent. The additional energy required to compress the captured CO_2 to approximately 2,200 psig would increase the energy footprint (including emission of criteria pollutants and GHGs) of the proposed boiler by 40 to 60 percent. Captured and compressed CO_2 must be transported to a storage facility or end use, such as enhanced oil recovery. Storage facilities are not currently

[14] The RBLC decisions listed in Table 5-8 are based on BACT decisions posted on EPA's RBLC website as of July 26, 2013.

commercially available within the vicinity of the SPI-Anderson site. There are no nearby petroleum extraction operations or industrial processes that would be able to accept the volume of CO_2 SPI would be emitting. SPI estimated that the oil field nearest to the Anderson facility is located in Brentwood, California, approximately 25 miles west of Stockton, California. Using estimates from a study by the Global CCS Institute, SPI estimated that the cost of installing a CCS system would be would cost approximately $29,000,000[15], and the cost of constructing a pipeline to transport CO_2 from the Anderson facility to Brentwood, California would cost approximately $109,907,547[16]. Both of these figures exceed the cost of a new or modified facility. SPI estimated that adding a cogeneration unit similar to that proposed by SPI for the Anderson facility would cost approximately $75,000,000. Furthermore, SPI estimated that to construct a lumber manufacturing facility with a production capacity similar to that of the existing Anderson facility would cost approximately $80,000,000. Accordingly, based on these costs, CCS is being eliminated as a GHG control option due to its disproportionate costs.

Removal of NO_x Control System (SNCR)
Elimination of the SNCR system used to reduce NO_x emissions from the boiler would potentially reduce 53.4 tpy of N_2O emissions, which is only 3.7% of the total CO_2e that is estimated to be emitted from the cogeneration project. Additionally, this alternative would result in increased NO_x emissions (i.e., 267 tpy NO_x projected to be emitted from the boiler). Therefore, EPA is eliminating this control option.

Catalytic Destruction/Oxidation
SPI estimated that a catalytic destruction/oxidation system would have an annualized cost of approximately $2,379,713. However, this cost would potentially reduce only 1.6 percent of the total GHG emissions (i.e., CH_4 and N_2O expressed as CO_2e), as shown in Table 5-4. Since CH_4 and N_2O emissions are expected to be very low, particularly in terms of CO_2e, EPA considers the construction and operating costs of a catalytic destruction / oxidation system to control these pollutants to be excessive. Therefore, EPA is eliminating this control option.

Addition of N_2O-Abating SCR System
SPI estimated that the addition of a N_2O-abating SCR system would have an annualized cost of approximately $1,276,065. However, this cost would potentially reduce only 1.4 percent of the total GHG emissions (i.e., CH_4 and N_2O expressed as CO_2e), as shown in Table 5-4. Since N_2O emissions are expected to be very low, particularly in terms of CO_2e, EPA considers the construction and operating costs for the control alternative to be excessive. Therefore, EPA is eliminating this control option.

Good Boiler Design, Good Combustion Practices, and Efficient Operation / Proper Combustion Practices and Use of a Properly Designed Boiler / Utilization of Biomass Fuel Alone
These control options are considered the baseline level. SPI anticipates that the proposed biomass boiler will be constructed with an energy efficient design that will ensure proper

[15] *Biomass-Fired Cogeneration Project: Best Available Control Technology Analysis for Greenhouse Gases, Sierra Pacific Industries Lumber Manufacturing Facility Anderson, California,* August 15, 2013, section 6, p. 28.
[16] SPI Anderson email response to EPA dated September 14, 2013.

combustion. SPI will operate the boiler according to the manufacturer's specifications to ensure that it is operated efficiently. SPI will operate the boiler in a cogeneration unit, generating electricity as well as steam for drying lumber. SPI will use biomass as its primary fuel. These control options are expected to have a positive energy and environmental impacts.

5.1.5 Step 5 – Select BACT

Based on a review of the available control methods for GHG emissions from biomass-fired boilers and other pertinent information used to evaluate the feasibility of these methods, we have concluded that BACT for the proposed biomass-fired stoker boiler is (1) 0.36 pounds of CO_2e per pound of steam (12-month rolling average basis), (2) combustion of biomass at all times except during periods of startup, shutdown and flame stabilization (in which natural gas fuel is allowed to be combusted), and (3) energy efficient design and use of good combustion and operational and maintenance practices as described in SPI's permit application and subsequent submissions to the EPA, which include, but are not limited to, (i) construction and operation of an efficient, state-of-the-art, air-cooled, reciprocating stepgrate stoker boiler that ensures good combustion; (ii) operation of the boiler as a cogeneration unit at the Facility; and (iii) operation and maintenance of the boiler in accordance with the manufacturer's recommendations. The CO_2e limit applies at all times, including during startups and shutdowns.

5.2 GHG BACT Analysis – Emergency Engine

The project includes a 256 hp (190 kW) natural gas-fired emergency engine to run the emergency boiler recirculation pump. This emission unit would be used if the cogeneration unit had to be shut down when power from the grid was unavailable. Planned operation for this piece of emergency equipment will be restricted to testing and maintenance (i.e., a maximum of 100 hours per year). The limited operation of this unit results in minimal annual emission rates. This equipment is subject to BACT for GHGs. A top-down BACT analysis has been performed and is summarized below.

5.2.1 Step 1 – Identify Available Control Technologies

In general, the options for reducing GHGs from the emergency engine fall into three categories: inherently low-emitting processes, clean fuels, and add-on control technologies.

5.2.2 Step 2 – Eliminate Technically Infeasible Control Technologies

Inherently Low-Emitting Processes
The purpose of the emergency boiler feedwater pump is to provide a quickly deployable source of power that will be available when electrical power from the grid is not available to operate the

electric motors that power the feedwater pumps that would be relied upon to circulate water through the boiler during a normal shutdown process. EPA is not aware of any technologies that have been designed to reduce the GHG emissions from natural gas-powered emergency engines generators. Energy efficiency of the engine design is the best way to minimize the emissions of GHGs from these sources. Since the EPA's engine emission standards for other criteria pollutants are based on the emission rate of the pollutant per unit of energy output, engine manufactures have employed a combination of reducing the mass emission rate of the pollutant(s) and increasing the overall efficiency of the engines. Therefore, compliance with EPA's engine standards is considered technically feasible for this control option.

Clean Fuels
SPI has determined that the only real alternative to a natural gas-fired pump is a diesel-fired pump, which can produce the same or more GHG emissions. Natural gas is considered the fossil fuel that generates the least GHG emissions per unit of energy produced. The only clean fuel to consider for the engine is natural gas. This control option is technically feasible only for natural gas since already SPI proposes to use this fuel in the engine.

Add-On Control Technologies
The emergency engine is limited to 100 hours of operation for maintenance, and must be available quickly and reliably, an add-on control that complicates operation and potentially reduces engine readiness, and compromises the emergency role of the engine. Installing an add-on control technology, such as CCS, is not feasible due to the nature of the engine.

5.2.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The remaining control options are the use of a natural gas-fired engine that meets EPA's engine standards for emergency engines.

5.2.4 Step 4 – Evaluate Most Effective Controls and Document Results

The remaining control options are the use of a natural gas-fired engine that meets EPA's engine standards for emergency engines.

5.2.5 Step 5 – Select BACT

EPA proposes that BACT for GHGs is the use of a natural gas-fired engine that meets EPA's engine standards in 40 CFR Part 60, Subpart JJJJ for emergency engines.

6. Ambient Air Quality Impact Analysis

CAA Section 165 and EPA's PSD regulations at 40 CFR 52.21 specify that a facility's emissions of NAAQS pollutants should be evaluated to determine whether they would cause or contribute to a violation of (1) the applicable NAAQS, or (2) the applicable Class I and II PSD increments. EPA has determined that this permit modification does not require an ambient air quality impact analysis for GHG emissions because there is no NAAQS or PSD Increments for GHG pollutants and it is therefore not possible to compare the modification's GHG emissions to a standard or increment.

Furthermore, although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. (*See* online docket #I.64, *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) at p. 48).

7. Additional Impact Analysis

The PSD regulations at 40 CFR 52.21(o) require that EPA evaluate other potential impacts on 1) soils and vegetation; 2) visibility impairment; and 3) growth. The scope 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.

7.1 Soils and Vegetation

The additional impact analysis includes consideration of potential impacts to soils and vegetation associated with the SPI's emissions. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis requirements of the rules related to GHGs. (*See* online docket #I.64, *PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011)* at p. 48).

7.2 Visibility Impairment

The additional impact analysis also evaluates the potential for visibility impairment (*e.g.*, plume blight) associated with SPI-Anderson. In EPA's Statement of Basis and Ambient Air Quality Impact Report issued for public comment on September 13, 2012, we concluded that we do not expect the proposed project will contribute to visibility impairment. (*See* online docket #III.02, *SPI-Anderson Ambient Air Quality Impact Report_12SEP12* at pp. 43-44). GHG emissions are not known to affect visibility. Therefore, we conclude that our visibility assessment has not changed as a result of the PSD review of GHG emissions.

7.3 Growth

The growth component of the additional impact analysis involves a discussion of general commercial, residential, industrial, and other growth associated with SPI-Anderson. 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.

In EPA's Statement of Basis and Ambient Air Quality Impact Report issued for public comment on September 13, 2012, we concluded that the proposed project is not expected to result in any significant growth in the area. (*See* online docket #III.02, *SPI-Anderson Ambient Air Quality Impact Report_12SEP12* at pp. 44-45). Specifically, the facility is still expected to employ approximately eight additional workers. In addition, the project will utilize existing roads and infrastructure, and no additional roads or transportation infrastructures are proposed for construction. Therefore, our growth assessment has not changed as a result of the PSD review of GHG emissions.

8. 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.

In EPA's Statement of Basis and Ambient Air Quality Impact Report dated September 2012, EPA stated that it had concluded that the project will have no likely adverse effect on any endangered or threatened species or designated critical habitat. EPA is correcting this statement, to clarify that the EPA has concluded that the project will have no effect on any endangered or threatened species or designated critical habitat. As stated in EPA's September 2012 AAQIR, construction activities resulting from the proposed modification will occur on SPI-Anderson's existing facility footprint and 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. (*See* online docket #III.02, *SPI-Anderson Ambient Air Quality Impact Report_12SEP12* at p. 45) This conclusion is supported in particular by the July 9, 1999 *Conservation Guidelines for the Valley Elderberry Longhorn Beetle* from the USFWS, which state 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* at p. 3). Discussions with the U.S. Fish and Wildlife Service (FWS) support EPA's conclusion, and have confirmed that this conclusion will not change as a result of the PSD review of GHG emissions from the project.

9. 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).

EPA previously 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. Our previous conclusion has not changed as a result of the PSD review of GHG emissions.

10. Public Comment Period, Procedures for Public Hearing

10.1 Public Comments

Any interested person may submit written comments regarding today's proposed PSD permit modification. All written comments on today's proposed action must be received by EPA Region 9 via e-mail by **December 13, 2013**, or postmarked by **December 13, 2013**. Comments must be sent or delivered in writing to Shaheerah Kelly at one of the following addresses:

E-mail: R9airpermits@epa.gov

U.S. Mail: Shaheerah Kelly
U.S. Environmental Protection Agency, Region 9 (AIR-3)
75 Hawthorne Street
San Francisco, CA 94105-3901

Phone: (415) 947-4156

Alternatively, written comments may be submitted to EPA Region 9 at the Public Hearing for this matter that will be held on December 10, 2013, as described below.

Comments should address the proposed PSD permit modification including, but not limited to, 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.

10.2 Public Information Meeting and Public Hearing

Public Information Meeting: To facilitate opportunities for interested persons to provide informed oral presentations at the public hearing describe below, EPA Region 9 will hold a Public Information Meeting for the purpose of providing interested parties with additional information and an opportunity to ask questions and obtain answers to questions about for informal discussion of the proposed Project. The date, time and location of the Public Information Meeting are as follows:

Date: December 10, 2013
Time: 4:30 PM – 6:00 PM
Location: City of Anderson Community Center
1887 Howard Street
Anderson, California 96007

Public Hearing: Pursuant to 40 CFR 124.12, EPA Region 9 also intends to hold a Public Hearing to provide the public with further opportunity to comment on today's proposed PSD permit modification. At this Public Hearing, any interested person may provide written or oral comments and data pertaining to today's PSD permit modification. The date, time and location of the Public Hearing are as follows:

Date:	December 10, 2013
Time:	7:00 PM – 9:00 PM
Location:	City of Anderson Community Center 1887 Howard Street Anderson, California 96007

If you are a person with a disability and require a reasonable accommodation for this event, please contact Philip Kum at kum.philip@epa.gov or at (415) 947-3566. If possible, requests should be made at least 5 business days in advance of the event to ensure proper arrangements can be made.

10.3 Availability of Information

All information submitted by the applicant is available as part of the administrative record. The proposed PSD permit modification, this Supplemental AAQIR, the AAQIR dated September 2012, the 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 Shaheerah Kelly at (415) 947-4156 at least 72 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 Region 9's proposed PSD permit modification, this Supplemental AAQIR, and the AAQIR dated September 2012 are also available for review at the (1) Shasta County Air Quality Management District at 1855 Placer St., Suite 101 in Redding, CA 96001; (2) Anderson Public Library at 3200 W. Center Street in Anderson, CA 96007; (3) Redding Public Library at 1100 Parkview Ave. in Redding, CA 96001; and (4) Shasta Lake Gateway Library at 4150 Asby Court in Shasta Lake, CA 96019.

All written comments that are received on today's proposed action 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. A transcript of the public hearing will also be included in the public docket. 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.

10.4 Final Permit Decision

EPA Region 9 will consider all new written and oral comments submitted during the public comment period, including those provided at the public hearing, before taking final action on the PSD permit modification. EPA Region 9 will send notice of the final decision to each person who provides contact information and who: (i) submits comments during the public comment period, including oral comments provided at the public hearing; or (ii) requests notice of the final permit decision. EPA Region 9 will respond to all new 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. Our decision is appealed to the EAB pursuant to 40 CFR Part 124.19. Please note that the EAB's July 18, 2013 decision remanding EPA Region 9's February 19, 2013 permit modification stated: "Once [EPA Region 9] issues a final permit decision following the public hearing required by the remand, that final permit decision and the Board's decision in this matter become final agency action subject to judicial review. 40 CFR §124.19(l). . . . The Board is not requiring, and will not accept, an appeal to the Board of the final permit decision for the Project following remand in this case." *In re Sierra Pacific Industries*, PSD Appeal Nos. 13-01 to 13-04, slip op. at 67 (EAB July 18, 2013); 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 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.

10.5 EPA Contact Information

If you have questions, please contact Shaheerah Kelly at (415) 947-4156 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 Shaheerah Kelly at (415) 947-4156 or send an e-mail at R9airpermits@epa.gov, or visit EPA Region 9's website at http://www.epa.gov/region09/air/permit/psd-public-guidelines.html.

11. 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 for GHG emissions as well as NOx, CO, PM, PM_{10} and $PM_{2.5}$. 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, our AAQIR dated September 2012, this Supplemental AAQIR, and related materials to the public for review, and make a final decision after considering any public comments on our proposal.