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DR-5

PSD PERMIT APPLICATION AND MODELING PROTOCOL

Prevention of Significant Deterioration

PSD PERMIT APPLICATION
For The

Palmdale Energy Project

Palmdale, California

Submitted to

Environmental Protection Agency, Region IX

Submitted by

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Section 1 INTRODUCTION

Palmdale Energy, LLC (Palmdale Energy), a solely owned subsidiary of Summit Power Project Holdings, LLC, is filing this PSD permit application with EPA Region 9 for the Palmdale Energy Project (PEP).

Palmdale Energy proposes to construct, own, and operate the Palmdale Energy Project (PEP or Project), which is a rapid or fast start design. The PEP consists of a natural gas-fired fast start combined-cycle generating system (standard 2 X 1 configuration) to be developed on an approximately 50-acre site in the northern portions of the City of Palmdale (City). The combined-cycle equipment utilizes two Siemens SGT6-5000F natural gas-fired combustion turbine generators (CTG), two heat recovery steam generators (HRSG), and one steam turbine generator (STG). The facility will utilize an auxiliary boiler to facilitate the fast start cycle for the combustion turbines. In addition, the facility will have an emergency fire-pump system and an emergency electrical generator on site. Process cooling for the combined cycle system will be achieved by dry cooling technology.

The Project will have a nominal electrical output of 645 MW at average annual conditions and commercial operation is planned for summer 2019/summer 2020. The Project will be fueled with natural gas delivered via a new natural gas pipeline. The Southern California Gas Company (SCG) will design and construct the approximately 8.7-mile pipeline in existing street rights-of-way (ROW) within the City of Palmdale.

Pursuant to the attainment status of the Antelope Valley Air Quality Management District and the PSD regulations in 40 CFR 52.21, this PSD application addresses emissions and impacts for the following pollutants only: nitrogen dioxide (NO_2 - NOx), carbon monoxide (CO), volatile organic compounds (VOC), total suspended particulate matter (TSP), particulate matter with aerodynamic diameters less than or equal to 10 microns (PM_{10}), particulate matter with aerodynamic diameters less than or equal to 2.5 microns ($PM_{2.5}$), and greenhouse gases (GHGs). Emissions and impacts of SO_2 (SO_x) are not addressed in this analysis.

1.1 PROJECT SCHEDULE

Construction of the project is scheduled to begin as soon as financing closes and after all final project permits and approvals. Construction is anticipated to take approximately 23 months, with commissioning and operations commencing as early as the summer of 2019.

1.2 APPLICATION ORGANIZATION

Section 1 presents the introduction, applicant information, project schedule, and application organization. Section 2 presents the proposed Project description. Section 3 presents the regulatory analysis for the identified federal regulations. In addition section 3 summarizes the other permitting programs that are being pursued concurrently with the PSD permitting process. Section 4 presents data on the regional and environmental setting, i.e., air quality, population and land use, climate, soils and vegetation. Section 5 presents the "top down" BACT analysis for the proposed facility systems. Section 6 presents the detailed discussion of the air quality modeling analysis. Section 7 presents the results of the air quality modeling and impact analysis studies. Section 8 presents data on the socioeconomic and growth inducing aspects of the project. Section 9 presents the summary of the biological studies and document references. Section 10 presents the cultural analysis for the project site and surrounding area. Section 11 presents the summary and conclusions of the overall air quality analysis. Section 12 presents the references used in preparing the PSD application.

1.3 PROJECT CONTACTS

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Section 2 PROJECT DESCRIPTION

The Palmdale Energy Project (PEP) is proposing to construct and operate a fast start (Flex Plant) 645 MW (nominal average annual rated) natural gas-fired combined-cycle power plant. The Flex Plant design project will operate up to approximately 8,000 hours per year, with an expected facility capacity factor at 60 to 80 percent. However, the dispatch profile may change as market conditions evolve. As a result of the potential dispatch profiles, and to permit the possible worst case operational scenarios, two (2) additional operational profiles were considered beyond the base load case which are based on more of a cycling or peaking type of project. Thus, as discussed in the sections below, the worst-case daily and annual emissions profiles were assessed and will be dependent upon each pollutant and which worst-case dispatch assumption produces the maximum annual potential to emit.

The project will consist of the following:

- Installation of two (2) Siemens SGT6-5000F Combustion Turbine Generators, each rated at a nominal 214 MW each (average annual). Each turbine will be equipped with Dry Low NOx (DLN) combustors and evaporative inlet air cooling.
- Installation of two (2) fired heat recovery steam generators (HRSGs) with a supplemental firing rate of 193.1 MMBtu/hr (HHV),
- A steam turbine rated at 276 MW (average annual including duct firing)
- SCR and CO catalyst systems on both turbine/HRSG power trains.
- Flex Plant Design allowing for fast plant start and load following capabilities
- Installation of an auxiliary boiler rated at 110 MMBtu/hr, firing natural gas. The boiler will provide auxiliary steam when the main power block is offline and during startups. The boiler will be equipped with ultralow NOx burners and flue gas recirculation (FGR). The use of this boiler will aid the fast startup design.
- Installation of air cooled condenser (dry cooling) to provide cooling and heat rejection from the power block process
- A diesel fired emergency electrical generator engine,
- A diesel fired fire pump engine,
- Necessary support systems and processes.

The Project design will incorporate the air pollution emission controls designed to meet current BACT/LAER determinations. These controls will include DLN combustors in the CTGs and low NOx duct burners to limit nitrogen oxide (NOx) production, Selective Catalytic Reduction (SCR) with aqueous ammonia for additional NOx reduction along with an oxidation catalyst to control carbon monoxide (CO) and volatile organic compounds (VOC) emissions. The ammonia slip (in the turbine/HRSG exhaust) will be limited to 5 parts per million (ppm). The auxiliary boiler will incorporate low NOx burners and flue gas recirculation in order to limit the emissions of NOx. Fuels to be used will be pipeline specification natural gas in the turbines, duct burners and auxiliary boiler, and California ultra-low-sulfur diesel fuel in the fire pump and generator set engines. The two proposed diesel internal combustion engines will meet all applicable EPA Tiered emissions standards based on engine type, rating, design, fuel, and service profile.

The Flex Plant rapid start design will consist of the following major equipment.

- Two 214 MW Siemens SGT6-5000F combustion turbines with inlet evaporative cooling
- One 276 MW Siemens steam turbine
- Two natural gas fired 193.1 MMBtu/hr HRSGs
- One 110 MMBtu/hr auxiliary boiler
- One air-cooled condenser
- One diesel powered fire pump
- One diesel powered emergency generator

All power from the facility will be delivered to the California power grid under the control of the California Independent System Operator (CAISO).

The turbine equipment output specifications are summarized in Table 2-1 as follows:

Table 2-1
Combustion Equipment Output Specifications

Parameter	Minimum Cold Day (23°F)	Annual Average Day (64°F)	Maximum Hot Day (108°F)
Case # (Temperature Conditions)	2	12	22
Net Power, MW	714.4*	699.4	664.3
Net Heat Rate, btu/kW-hr (HHV)	6909	6887	7053

Parameter	Minimum Cold Day (23°F)	Annual Average Day (64°F)	Maximum Hot Day (108°F)
Gross GT Power, MW	457.4	440.7	419.2
Gross ST Power, MW	274.6	276.2	262.4
Ref: Siemens Performance data sheets, with duct firing mode On. Appendix A. HHV ~= LHV x 1.109 * Plant output will be limited to 700 MW via automatic control system.			

Equipment specifications are summarized as follows:

Combustion Turbines and Duct Fired HRSGs (2)

- Manufacturer: Siemens
- Model: SGT6-5000F
- Fuel: Natural gas
- Heat Input: 2409.95 MMBtu/hr (Case 7-ISO day, baseload, with duct firing)

  2467.10 MMBtu/hr (Case 2-Cold day, baseload with duct firing)
- Maximum Fuel consumption: <=105,943 lbs per hour (Case 2-baseload, cold day, with duct firing)
- Exhaust flow: <=4.383,814 lbs/hr (Case 2-baseload, cold day, with duct firing)
- Exhaust temperature: ~186 degrees Fahrenheit (□F) at the stack exit
- Duct Burners rated at 193.1 MMBtu/hr firing natural gas (Case 2, baseload)
- Steam Turbine rating at 276 MW (nominal ISO baseload)

Fire Pump (1)

- Manufacturer: Clarke or equivalent (Tier 3)
- Fuel: Ultra-low sulfur diesel
- Horsepower: 140 BHP

Emergency Gen Set (1)

- Manufacturer: Caterpillar or equivalent (Tier 2)
- Fuel: Ultra-low sulfur diesel

- Horsepower: 2011 BHP (1500 kW)

Auxiliary Boiler (1)

- Manufacturer: Cleaver Brooks or equivalent
- Model: NB-300D-65 Water tube type or equivalent
- With ultra-low-NO_x burners and flue gas recirculation (FGR)
- Fuel: Natural gas
- Rating: 110 MMBtu/hr

Dry Cooling System

The heat rejection from the steam cycle will be via an air cooled condenser (ACC). The ACC is a direct cooling system where the steam exhaust from the low pressure turbine section is condensed inside air-cooled finned tubes. The ACC is made of modules arranged in parallel rows. Each module contains a number of finned tube bundles. An axial flow fan located in each module forces the cooling air across the heat exchange area of the fin tubes. The heat rejection system will include the ACC, the supporting structure, steam ducting from the LP turbine interface, auxiliaries such as the condensate and drain pumps, condensate and duct drain tanks, the air evacuation pumps, and related piping works and instrumentation.

Fuels

Natural gas will be the only fuel used during plant operation with the exception of the emergency diesel equipment, which will fire ultra-low sulfur diesel fuel. Natural gas combustion results in the formation of NO_x, CO, VOCs, SO_2, TSP, PM10, and PM2.5. Because natural gas is a clean burning fuel, there will be minimal formation of combustion TSP, PM10, PM2.5, and SO_2.

The fuel used on this project is similar to the fuels used on similar combined cycle power generation facilities. The natural gas will meet the California Public Utility Commission (PUC) grade specifications. The diesel fuel sulfur will be limited to 15 ppm, and will meet all California certified low sulfur diesel specifications. Table 2-2 presents a fuel use summary for the facility. Fuel use values are based on the maximum heat rating of each system, fuel specifications, and maximum operational scenario.

Table 2-2
Estimated Fuel Use Summary for the Project

Source	Fuel	Per Hour, mmscf	Per Day, mmscf	Per Year, mmscf
CT-1 with DB	Natural gas	2.4093	57.8226	17630.43
CT-2 with DB	Natural gas	2.4093	57.8226	17630.43
CT-1 w/o DB	Natural gas	2.2206	53.2932	14100.82
CT-2 w/o DB	Natural gas	2.2206	53.2932	14100.82
Auxiliary Boiler	Natural gas	0.1074	2.5776	524.65
Source	**Fuel**	**Per Hour, gals**	**Per Day, gals**	**Per Year, gals**
Diesel Fire Pump	Diesel Fuel	9.2	9.2	478.4
Emergency Generator	Diesel Fuel	104.6	52.3	2719.6

CT – Combustion Turbine
DB – Duct Burner
The fire pump will be tested up to 1 hour per day and 1 day per week, or 52 hours per year, per NFPA testing requirements.
The EGS will be tested up to 0.5 hour per day and 1 day per week, or 26 hours per year
HHV of fuel is 1024 BTU/SCF (average)
DB cases: Hourly and daily fuel rates based on cold day (Case 2) for 24-hours, annual fuel rate based on annual average 64 degree F (Cases 11 and 12).
Non-DB cases: Hourly and daily fuel rates based on cold day (Case 1), annual fuel rate based on average annual 64 degree F (Case 11).
Max turbine hours per day = 24 (including SU/SD hours). Max turbine hours per year (see Appendix A)
Max Auxiliary boiler operation up to 24-hours per day, 4,884 hours per year.

2.1 PROJECT EMISSIONS

The approximately 50 acre site is currently vacant, and consists of open desert lands. There are no current air pollution sources on the proposed site (except for naturally occurring dust emissions), and there are no facilities on the current site that are permitted by the AVAQMD or EPA Region 9.

2.1.1 Facility Emissions

Installation and operation of the project will result in the emissions signature for the site that will be greater than 100 tpy for some criteria pollutants, and as such the project will be considered a major NSR source for NO_x, CO, VOC, and TSP/PM10/2.5 under the AVAQMD rules. The project will trigger the requirements of the Federal PSD program since the emissions of one or more criteria pollutants will exceed the 100 tpy major source applicability thresholds. The applicability determination for PSD is based on the worst case estimate of post-commissioning year emissions. Criteria and hazardous pollutant emissions from the new combustion turbines/HRSGs and auxiliary equipment are delineated in the following sections. Backup data for both the criteria and hazardous air pollutant emission calculations are provided in Appendix A.

The hourly, daily and annual emissions for all criteria pollutants are based upon a series of worst-case assumptions for each pollutant. The intent was to envelope the project emissions based upon the three (3) dispatch profiles provided in Appendix A and below. The daily operation always assumes 24 hours of operation with at least one cold or warm/hot start and one shutdown (except for PM, which is based on 24-hour of continuous operation). The worst-case annual emissions profiles will be dependent upon pollutant and which worst-case dispatch assumption produces the maximum annual potential to emit. Thus, the following assumptions will apply to the proposed project:

- For the highest annual emissions of NO_x, TSP/PM10/2.5 and CO_2e, up to 7,960 hours of operation at base load, up to 35 warm starts, five (5) cold start, and up to 40 shutdowns per year for a total of 8,000 hours per year with up to 24 hours per day of operation. For this scenario, the auxiliary boiler is expected to operate up to 836 hours per year. This is identified on the attached spreadsheet in Appendix A as Operational Scenario 1.

- For the highest annual emissions of CO and VOC, up to 3,625 hours at base load with up to 360 hot starts, 360 warm starts, five (5) cold starts, and up to 725 shutdowns for a total of 4,320 hours per year with up to 24-hour per day of operation. For this scenario, the auxiliary boiler is expected to operate up to 4,884 hours per year. This is identified in Appendix A as Operational Scenario 2.

- The third Operational Scenario is based on 4,470 hours per year of base load operation, up to 180 hot starts, 360 warm starts, 5 cold starts, and up to 545 shutdowns per year for a total of 5,000 hours per year with up to 24-hours per day of operation. For this scenario, the auxiliary boiler is expected to operate up to 4,136 hours per year. This is identified in Appendix A as Operational Scenario 3.

- All three emissions scenarios include 1,500 hours per year for the duct burners in the HRSG with up to 24 hours per day of operation, and 50 hours per year for fire pump and 26 hours per year for the emergency generator testing.

Based on the enveloping of emissions, the goal for the PSD permit is to not have any limits on the number of turbine start events (either cold, warm or hot), the number of hours of facility operation, the number duct burner operational hours, or the number shutdown events. By enveloping the emission scenarios, we presented several ways in which the facility may operate, but there could be other scenarios with more starts and less run-time hours. Thus, the applicant would propose that the facility limits be based on total short-term and annual emissions rather than operational hours or operational events. The turbines/HRSGs will be required to install continuous emission monitors (CEMs) for NO_x and CO. Hourly fuel use monitoring along with source test requirements will establish a compliance method to allow for continuous tracking of all emissions at the PEP. For example, the maximum annual emissions of NO_x at 139 tons per year would establish the facility potential to emit (PTE). PEP would propose and accept hourly, daily and annual emission limits for this pollutant, but would propose that the permit would not contain any limit on the number of start events or hours of operation as the established emission limits would be continuously monitored. This way, the facility operational profiles would be solely based on PTE rather than hours which would allow for a flexible response to changing power market conditions, which is the fundamental business purpose of the proposed facility. Thus, the short-term and annual emissions limits would establish the facility PTE rather than the individual operational profiles.

During the first year of operation, plant commissioning activities, which are planned to occur over an estimated 639 operating hours during the first year of operation, will have higher hourly and daily emission profiles than during normal operations in the subsequent years of operation. The emissions during the first year of operation are presented below and were included in the air quality modeling analysis along with subsequent post commissioning yearly emissions. As stated earlier, these emissions are not considered, per EPA guidance, in the establishment of the facility PTE values.

The proposed project will be a major NSR source as defined by the AVAQMD Regulation XIII and will be subject to AVAQMD requirements for emission offsets and air quality modeling analyses for criteria pollutants and toxics. The applicant has prepared an air quality emissions and impact analysis to comply with the AVAQMD and the CEC regulations. The modeling analysis includes impact evaluations for those pollutants shown in Table 2-3 and the CEC requirements for evaluation of project air quality impacts. The applicant has also prepared a modeling protocol to address the PSD impact analysis requirements.

The emissions presented in Table 2-3 are the worst-case potential emissions on an annual basis. Table 2-3 also presents other pertinent data to be used in the PSD emissions and impact analysis.

Table 2-3
Significant Emissions Threshold Summary

Pollutant	Project PTE, tpy	Federal Attainment	Major Source Thresholds PSD, tpy		Significant Emissions Rate, tpy	Major Source (PSD)	Significant Emissions Increase
NO_x	139	Y	100		40	PSD	Y
SO_2	11	Y	100		40	No	N
CO	351	Y	100		100	PSD	Y
PM10	81		100		15	PSD	Y
PM2.5	81	Y	100		10	PSD	Y
VOC (O_3 Precursor)	52	N	100		40	PSD	Y
CO_2e	2,117,730	-	-	-	75,000	PSD	Y

The project will trigger the major new source thresholds for Prevention of Significant Deterioration. Criteria and hazardous pollutant emissions from the new combustion turbines, auxiliary boiler, and emergency equipment are delineated in the following sections, while emissions of hazardous air pollutants are delineated below. Support data for both the criteria and hazardous air pollutant emission calculations are provided in Appendix A.

The emissions calculations presented in the application represent the highest potential emissions based on the proposed operational scenarios.

2.1.1.1 Normal Operations

Operation of the proposed process and equipment systems will result in emissions to the atmosphere of both criteria and toxic air pollutants. Criteria pollutant emissions will consist primarily of NO_x, CO, VOCs, sulfur oxides (SO_x), total suspended particulates (TSP), PM10, and PM2.5. Air toxic pollutants will consist of a combination of toxic gases and toxic PM species. Table 2-4, lists the pollutants that may potentially be emitted from the Project.

Table 2-4
Potentially Emitted Criteria and Hazardous Air Pollutants

Criteria Pollutants	Hazardous Pollutants (cont'd)
NO_x	Benzene
CO	1-3 Butadiene
VOCs	Ethylbenzene
SO_x	Formaldehyde
TSP	Hexane (n-Hexane)
PM10/2.5	Naphthalene
	Propylene Oxide
Hazardous Pollutants	Toluene
PAHs	Xylene
Acetaldehyde	
Acrolein	

2.1.1.2 Criteria Pollutant Emissions

Tables 2-5 through 2-9 present data on the criteria pollutant emissions expected from the facility equipment and systems under worst-case operating conditions. The maximum hourly emissions are based on Case 2 (23°F day at base load operation with duct firing) or are based on cold start maximum hourly emission rates. A cold start is defined as a one hour event with the turbine/HRSG stack emissions in BACT compliance at the end of the first hour (the duct burners will not be operated during the first hour of any type of startup). The worst case day for emissions is defined at one cold start (39 minutes of start plus 21 minutes of base load, no duct burner), one shutdown (30 minutes of shutdown plus 30 minutes of base load with duct burner), and 22 hours of base load operation with duct burner (Case 2).

As mentioned earlier, three (3) operational profiles were examined for this application and are summarized in Appendix A. The differences between the three operational profiles are based on annual run time hours and the total annual startup/shutdown events. For each operational profile, the number of hours for the auxiliary boiler will also vary as the boiler is used to keep the steam turbine in a warm state to allow for faster start times. For NO_x, TSP/PM10/2.5, and CO_2e, the maximum potential to emit is Operational Scenario 1, which has the most based loaded hours per year. For CO and VOC's, Operational Scenario 2 has the highest emissions, and is based on the case which has the most number of startup and shutdown hours. The Operational Scenario for the worst-case auxiliary boiler emissions is based on the Scenario 2, which like the case for CO and VOCs, this case has the least amount of base loaded hours of operation. Thus, for each pollutant, the maximum potential to emit is presented in Appendix A and in the tables below.

Table 2-5
Combustion Turbine/HRSG and Auxiliary Boiler Emissions
(Startup and Steady State Operation Per Turbine/HRSG)

Combustion Turbine/HRSG					
Pollutant	**Emission Factor and Units**	**Max Hour Emissions at Cold Startup (lb/hr)**	**Max Hour Emissions Steady State w/o DB (lb/hr)**	**Max Hour Emissions Steady State w/DB (lbs)**	**Max Daily Emissions (lbs)[a]**
NO_x	2.0 ppmvd	57.47	17.1	18.5	564.54
CO	2.0 ppmvd	419.44	10.4	11.3	1084.14
VOC	2.0 ppmvd	-	-	6.36	235.25
VOC	1 ppmvd	31.41	3.0	-	-
TSP/PM10/2.5[b]	<=0.0047 (CT) <=0.011 (DB) lbs/MMBtu	11.75	9.8	11.8	283.2
NH_3	5.0 ppmvd	13.79	15.8	17.2	412.8
CO_2e	116.89 lb/mmbtu	2,112,350 (Max TPY-Scenario 1)			

Auxiliary Boiler Emissions				
Pollutant	**Emissions Factor and Units**	**Max Hour Emissions (lb/hr)**	**Max Daily Emissions (lb/hr)**	**Max Annual Emissions (tpy)[c]**
NO_x	9.0 ppm	1.21	29.04	2.95
CO	50 ppm	4.07	97.68	9.94
VOC	15 ppm	0.55	15.84	1.61
TSP/PM10/2.5	0.007 lb/MMBtu	0.77	18.48	1.88
CO_2e	116.89 lb/MMBtu	-	-	31,430.9

[a] Worst-case 23-hour day based on Case 2 (23°F day) with one (1) warm start, one (1) hot start, two (2) shutdowns plus remaining 22.08 hours at full load with duct burner on. For PM, maximum daily assumes 24-hours of operation with the duct burner on. See Appendix A.

[b] Short term and annual fuel sulfur limit is based on 0.2 gr/100scf, per Sempra email to Summit Power.

[c] Auxiliary boiler annual emissions is based on Operational Scenario 2 with 4,884 hours per year and 24-hours per worst-case day. See Appendix A. Auxiliary boiler startup emissions are equal to a steady state hour.

Turbine/HRSG ppm reference = 15% O_2 dry

Auxiliary boiler ppm reference = 3% O_2 dry

CT = Combustion Turbine

DB = Duct Burner

Table 2-6
Startup and Shutdown Emissions Per Turbine

Parameter/Mode	Cold Startup to 100% Turbine Load	Warm Startup to 100% Turbine Load	Hot Start to 100% Turbine Load	Shutdown from 100% Turbine Load
NO_x, lbs/event	51.48	46.8	43.2	33.0
CO, lbs/event	415.80	378	304.8	75.9
VOC, lbs/event	30.36	27.6	27.6	19.8
TSP/PM10/2.5, lbs/event	8.32	7.56	6.48	4.07
Event Time, minutes (hours)	39 (0.65)	35 (0.583)	30 (0.5)	25 (0.417)
Maximum Number of Events/Year (Operational Scenario)	5 (Operational Scenario 1, 2 and 3)	360 (Operational Scenario 2 and 3)	360 (Operational Scenario 2)	725 (Operational Scenario 2)

* A 20% and 10% margin has been added to the startup and shutdown emissions, respectively. During the remaining minutes during the start hour, Case 1 (23ºF) full load, non-duct burner emissions are used.

Cold start event data is based on 100% turbine load at the end of the start cycle. Duct burner operation would not be available during the first hour of any start.

Table 2-7
Two Combustion Turbine/HRSG Emissions (Including Base Load with DB, Cold/Warm/Hot Startup and Shutdown, Whichever is Greater) for the Non-Commissioning Year

Pollutant	Emission Factor	Max Hour Emissions (pounds)	Max Daily Emissions (pounds)	Max Annual Emissions (tons)
NO_x	N/A	114.93	1129.07	138.24
CO	N/A	838.88	2168.28	341.08
VOCs	N/A	62.82	470.50	50.02
TSP/PM10/2.5	N/A	23.60	566.40	80.67
NH_3	N/A	27.58	825.60	124.68
CO_2e	N/A	-	-	2112350

See Appendix A, for detailed emissions and operational data.

Maximum hour based on two turbines in cold startup, except for TSP/PM10/2.5 which is based on Case 2 operation with duct burner.

Emergency equipment readiness testing will not occur during a turbine startup hour.

Maximum day is based on Operational Scenario 2 with two startups and shutdowns, with remaining hours at Case 2 operation with duct burner. PM10/2.5 based on 24-hour of Case 2 emissions with duct burner.

Maximum annual NOx, NH_3, CO_2e and PM10/2.5 based on Operational Scenario 1.

Pollutant	Emission Factor	Max Hour Emissions (pounds)	Max Daily Emissions (pounds)	Max Annual Emissions (tons)
Maximum annual CO and VOCs based on Operational Scenario 2. DB = Duct Burner				

Table 2-8
Diesel Fire Pump and Generator Engine Emissions

140 BHP Fire Pump (Tier 3)				
Pollutant	**g/hp-hr**	**Max Hour Emissions (pounds)**	**Max Daily Emissions (pounds)**	**Max Annual Emissions (tons)**
TSP/PM10/2.5	0.22	0.068	0.068	0.002
NO_x	2.80	0.864	0.864	0.022
CO	3.70	1.142	1.142	0.03
VOC	0.20	0.062	0.062	0.002
CO_2e	-	-	-	5.3
2011 BHP Emergency Generator (Tier 2)				
TSP/PM10/2.5	0.09	0.2	0.2	0.005
NO_x	3.78	8.38	8.38	0.218
CO	0.67	1.485	1.485	0.039
VOC	0.19	0.421	0.421	0.011
CO_2e	-	-	-	30.2
Notes: Diesel fuel S content of 15 ppm. SO2 emissions are not subject to PSD review for this facility. Emergency generator daily testing will be restricted to 30 minutes per test. The hourly emissions represent the 30 minute readiness testing runtime per test or 50 hours per year. The fire pump testing is based on 60 minutes per day, 50 hours per year.				

Table 2-9 presents a summary of the annual emissions for each operational scenario.

Table 2-9
PEP Maximum Potential to Emit
by Operational Scenario (Tons/Year)

Pollutant	Operational Scenario 1	Operational Scenario 2	Operational Scenario 3
NO_x	138.75	122.17	122.11
CO	102.43	351.02	289.60
VOCs	30.83	51.63	45.39

Pollutant	Operational Scenario 1	Operational Scenario 2	Operational Scenario 3
TSP/PM10/PM2.5	81.0	48.08	54.09
CO_2e	2,117,730	1,187,288	1,359,218
Emergency engine emissions not included. H2SO4 emissions (turbines/DB are less than or equal to 4.8 tpy. Siemens Energy-Caithness LIEC II, SGT6-5000(5), June 2011. Ammonia slip (NH3) emissions will range from 57.92 to 124.68 tpy dependent upon operational scenario.			

As discussed earlier, the goal of this application is to present three (3) operational profiles that would envelope the emissions on a pollutant specific basis, with the maximum from the three (3) profiles used to represent the PEP potential to emit.

Based on the emissions summarized in Table 2-9 and the previous tables, Table 2-10 presents the maximum proposed emissions for the PEP on a pollutant specific basis.

Table 2-10
Summary of Maximum Facility Emissions for the Project
(Highest Operating Scenario Values)

Pollutant	lbs/hour	lbs/day	tons/year
NO_x	116.14	1140.73	138.99
CO	842.95	2179.05	351.09
VOCs	63.79	472.30	51.64
TSP/PM10/2.5	24.57	568.21	81.01
CO_2e	-	-	2,117,775.06
Normal Operation Assumptions: For the highest annual emissions of NO_x, PM10/2.5 and CO_2e, up to 7,960 hours of operation at base load, up to 35 warm starts, five (5) cold start, and up to 40 shutdowns per year for a total of 8,000 hours per year with up to 24 hours per day of operation. For this scenario, the auxiliary boiler is expected to operate up to 836 hours per year. (Operational Scenario 1) For the highest annual emissions of CO and VOC, up to 3,625 hours at base load with up to 360 hot starts, 360 warm starts, five (5) cold starts, and up to 725 shutdowns for a total of 4,320 hours per year with up to 24-hour per day of operation. For this scenario, the auxiliary boiler is expected to operate up to 4,884 hours per year. (Operational Scenario 2) The third Operational Scenario is based on 4,470hours per year of base load operation, up to 180 hot starts, 360 warm starts, 5 cold starts, and up to 545 shutdowns per year for a total of 5,000 hours per year with up to 24-hours per day of operation. For this scenario, the auxiliary boiler is expected to operate up to 4,136 hours per year. (Operational Scenario 3) All three emissions scenarios include 1,500 hours per year for the duct burners in the HRSG with up to 24 hours per day of operation, and 50 hours per year for fire pump and 26 hours per year for the emergency generator testing. Total facility estimated maximum emissions (including turbine SU/SD emissions). Hourly emissions include the auxiliary boiler for all pollutants. The emergency generator is only included for PM10/2.5 hourly as the maximum hour for NOx, CO and VOCs is based on startup (no emergency engine testing). Daily emissions assume two (2) startups and two (2) shutdowns with the remaining hours at full load with duct burners, except for PM10/2.5 which is based on 24-hours of full load with duct burners. The auxiliary boiler is assumed to operate two hours for the worst-case day.			

In addition to the normal operational profiles presented above, during the first year of operation, plant commissioning activities will occur. These activities are planned to occur over an estimated 1,278 hours, and will have higher hourly and daily emission profiles than during normal operations in the subsequent years of operation. For commissioning, the worst-case hour and the worst-case day is assumed to be one (1) turbine undergoing first fire and synch checks with the other turbine in emissions and combustion tuning. No two turbines will be undergoing the same commissioning activity during any one hour or day until the final tuning and testing phase. The commissioning activities and emissions are, like construction, considered to be temporary, and as such the emissions are not counted towards PSD applicability, nor are they required to be modeled for any impact analyses.

Greenhouse Gas Emissions

At the time of filing, the applicant did not identify any federal regulations, other than the GHG Tailoring Rule and the proposed NSPS Subpart TTTT (40 CFR 60), that would apply or limit GHG emissions from the proposed facility and/or processes. Since the source is major for PSD for several identified criteria pollutants, and the proposed GHG emissions exceed the PSD GHG significant emission rate of 75,000 tpy, the source is subject to the GHG BACT provisions. NSPS Subpart TTTT will be applicable and is discussed further in the LORS analysis in Section 3.1.

2.2 PROJECT GHG ESTIMATES

GHG emissions have been estimated for both the construction and operation phases of the project.

Construction emissions are not presented as they are considered temporary and not subject to PSD applicability accounting.

Operational emissions of CO_2e will be primarily from the combustion of fuels in the turbine, auxiliary boiler, and the emergency equipment along with SF_6 emissions from the circuit breakers. Appendix A contains the support data for the GHG emissions evaluation. Estimated carbon dioxide equivalents emissions for the project operational phase, based on annual average conditions, are as follows:

CO_2e <= 2,117,775 tons/year (=1,925,250 metric tons/year)

The emission factors were derived from Tables C-1 and C-2 in the Federal Register Volume 74, No. 209, 10-30-2009, and the calculation methods are based on current best practices.

2.3 HAZARDOUS AIR POLLUTANTS

The facility will emit a number of substances that are classified as toxic and/or hazardous. The following tables delineate these pollutants and the expected emissions levels for each.

Table 2-11
HAP/Toxic Pollutant Emissions Estimates (lbs/hr)

Pollutant/Device	Turbine/HRSG 1	Turbine/HRSG 2	Auxiliary Boiler	Fire Pump	Emergency Generator
PAHs	0.000116	0.000116	0.0000107	-	-
Acetaldehyde	0.066	0.066	0.0000967	-	-
Acrolein	0.00911	0.00911	0.0000859	-	-
Benzene	0.00641	0.00641	0.000183	-	-
1-3 Butadiene	0.0000612	0.0000612	-	-	-
Ethylbenzene	0.00863	0.00863	0.000215	-	-
Formaldehyde	1.10	1.10	0.000387	-	-
Hexane	0.125	0.125	0.00014	-	-
Naphthalene	0.0008	0.0008	0.0000322	-	-
Propylene Oxide	0.023	0.023	-	-	-
Toluene	0.0342	0.0342	0.000838	-	-
Xylene	0.0126	0.0126	0.000623	-	-
DPM	-	-	-	0.0679	0.399

Table 2-12
HAP/Toxic Pollutant Emissions Estimates (lbs/year)

Pollutant/Device	Turbine/HRSG 1	Turbine/HRSG 2	Auxiliary Boiler	Fire Pump	Emergency Generator
PAHs	0.850	0.850	0.0525	-	-
Acetaldehyde	483	483	0.472	-	-
Acrolein	66.60	66.60	0.420	-	-
Benzene	46.90	46.90	0.892	-	-
1-3 Butadiene	0.448	0.448	-	-	-
Ethylbenzene	63.1	63.1	1.05	-	-
Formaldehyde	8080	8080	1.89	-	-
Hexane	913	913	0.682	-	-
Naphthalene	5.85	5.85	0.157	-	-
Propylene Oxide	169	169	-	-	-
Toluene	250	250	4.09	-	-

Xylene	92	92	3.04	-	-
DPM	-	-	-	3.50	10.4

Based on the data in Tables 2-11 and 2-12 the facility will not be a major source of HAPS/toxic pollutants. As such, a MACT determination is not required. In addition, it should be noted that diesel particulate matter (DPM) is not a federal HAP, but emissions from the diesel engines were characterized using DPM as the surrogate for all species, and as such DPM emissions are reported in Tables 2-11 and 2-12 for informational purposes.

Section 3 REGULATORY ANALYSIS

Prior to addressing the regulatory aspects of the PSD application, the project applicant wishes to briefly describe to EPA the status of the other applicable permitting programs for the proposed project.

The applicant has submitted an air quality impact analysis to both the Antelope Valley Air Quality Management District (AVAQMD) and the California Energy Commission (CEC). These applications include discussions of emissions calculations, control technology assessments, regulatory review and modeling analysis which include impact evaluations for criteria and hazardous air pollutants.

The project is expected to result in emissions that will exceed the AVAQMD Rule 1303 Major Facility significance thresholds for oxides of nitrogen (NO_x), carbon monoxide (CO), volatile organic compounds (VOCs), and TSP and fine particulate matter (TSP/PM10/2.5). Emissions of sulfur dioxide (SO2) are expected to be less than the major source thresholds.

The project will trigger AVAQMD and CEC modeling requirements. The air quality analysis has been conducted to demonstrate that impacts from NO_x, CO, SO_x, TSP, PM10 and PM2.5 will comply with the California and National Ambient Air Quality Standards (CAAQS/NAAQS) for the applicable averaging periods for the AVAQMD and CEC modeling requirements. Impacts from nearby sources (cumulative impacts) are also assessed for criteria pollutants.

The project will trigger the Prevention of Significant Deterioration (PSD) permitting requirements, which would be required for combined cycle design with a facility wide emissions equaling or exceeding 100 tons per year (tpy) for any criteria pollutant. This application represents the separate PSD permit application submittal for EPA Region 9 review.

The project will require an AVAQMD Regulation XIII New Source Review (NSR) permit as specified under Rules 1300-1320. Currently, the AVAQMD is federal attainment/unclassified for NO_2, SO_2, PM2.5, and CO. The area is in attainment for the federal PM10 standards as well, but is nonattainment for the federal 8-hour ozone (O_3) standard. The new facility will be a major new stationary source per AVAQMD New Source Review (NSR) Regulation XIII.

Worst-case annual emissions are summarized in Table 3-1 below and represent the operational scenario that produces the highest potential to emit.

Table 3-1
Facility PTE Summary

Pollutant	PEP TPY	AVAQMD Rule 1303 Major Facility Thresholds TPY	EPA Major PSD Source Thresholds (TPY)*
NO_x	139	25	40
CO	351	100	100
VOC	52	25	40
SO_x (see note)	11	25	40
TSP/PM10	81	15	15
PM2.5	81	15	10
CO_2e	2,117,730	-	75,000

*PSD major source is triggered for combined cycle turbine at 100 tpy, from which the major modification thresholds are then used for the remaining pollutants. PSD is not triggered for CO_2 emissions alone.

SO_2 emissions are presented for informational purposes only to show that such emissions are not subject to PSD review.

The project will require a PSD permit. Currently, the AVAQMD does not have delegation of the PSD program. Thus, the Environmental Protection Agency (EPA) Region 9 will require a separate PSD permit application. This document represents the PSD permit application.

3.1 APPLICABLE FEDERAL REGULATIONS

The federal EPA implements and enforces the requirements of many of the federal air quality laws. EPA has adopted the following stationary source regulatory programs in its effort to implement the requirements of the CAA:

- New Source Performance Standards (NSPS)
- National Emission Standards for Hazardous Air Pollutants (NESHAP)
- Prevention of Significant Deterioration (PSD)
- New Source Review (NSR)
- Title IV: Acid Rain/Deposition Program
- Title V: Operating Permits Program
- CAM Rule

Table 3-1 presents a summary of federal air quality regulations deemed applicable to the Project. Specific regulations are discussed in greater detail subsequent to the table.

Table 3-1
Summary of LORS - Air Quality

LORS	Applicability
CAAA of 1990, 40 CFR 50	Project operations will not cause violations of state or federal AAQS.
40 CFR 52.21 (PSD)	Impact analysis shows compliance with NAAQS, Project will be subject to PSD.
40 CFR 72-75 (Acid Rain)	Project will submit all required applications for inclusion to the Acid Rain program and allowance system, CEMS will be installed as required. The Project is subject to Title IV.
40 CFR 60 (NSPS)	Project will determine subpart applicability and comply with all emissions, monitoring, and reporting requirements. 40 CFR 60, Subpart KKKK will apply to the turbines/HRSGs. Subpart IIII will apply to the fire pump engine. 40 CFR 60 Subpart TTTT – CO2 emissions standards for base load combustion turbines.
40 CFR 70 (Title V)	Title V application will be submitted pursuant to the timeframes noted in AVAQMD Regulation XXX.
40 CFR 68 (RMP)	Project will evaluate substances and amounts stored, determine applicability, and comply with all program level requirements. The existing RMP and OCA will be evaluated for necessary revisions.
40 CFR 64 (CAM Rule)	Facility will be exempt from CAM Rule provisions.

LORS	Applicability
40 CFR 63 (HAPs, MACT)	Subpart YYYY applies to stationary combustion turbines constructed after 1-14-03 located at a major HAPs source. Emissions limits in the rule are currently stayed.

3.1.1 New Source Performance Standards (NSPS)

NSPS are federal standards promulgated for new and modified sources in designated categories codified in 40 CFR Part 60. NSPS are emission standards that are progressively tightened over time in order to achieve ongoing air quality improvement without unreasonable economic disruption. The NSPS impose uniform requirements on new and modified sources throughout the nation. The format of the standard can vary from source to source. It can be a numerical emission limit, a design standard, an equipment standard, or a work practice standard. Primary enforcement responsibility of the NSPS rests with EPA, but this authority has been delegated to the AVAQMD, which is enforced through Regulation 9.

Subpart A General Provisions.

Any source subject to an applicable standard under 40 CFR Part 60 is also subject to the general provisions of Subpart A. Because the Project is subject to Subparts IIII and KKKK, the requirements of Subpart A will also apply. The Project operator will comply with the applicable notifications, performance testing, recordkeeping and reporting outlined in Subpart A.

Subpart Db Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.

The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 100 MMBtu/hr. The rule imposes limits on SO_2 emissions for oil- and coal-fired units; limits on PM emissions for units that combust coal, wood or municipal solid waste, alone or in combination with other fuels; and limits on NO_x emissions for natural gas-fired units of 0.20 lb/MMBtu.

Subpart Db would only apply to the auxiliary boiler because it has a heat input rate exceeding 100 MMBtu/hr. This boiler will only be fueled with natural gas, thus Subpart Db does not limit SO_2 or PM emissions from natural gas–fired units. Subpart Db limits NO_x emissions to 0.20 lb/MMBtu from natural gas-fired units. The BACT-derived NOx emission limit of 0.011 lb/MMBtu is substantially less than the Subpart Db limit; thus the auxiliary boiler will comply with the NSPS requirements.

While the HRSGs and associated duct burners will be in excess of 100 MMBtu/hr, these units are exempt from the requirements of Db. Rather, they are regulated under Subpart KKKK.

Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

Subpart IIII is applicable to owners and operators of stationary compression ignition (CI) internal combustion engines that commence construction after July 11, 2005. Relevant to the proposed Project, the rule applies to the fire water pump CI engine and to the emergency electrical generator CI engine as follows:

(i) Non fire water pump engines manufactured after April 1, 2006;

(ii) Fire water pump engines with less than 30 liters per cylinder manufactured after 2009;

Or

(iii) Fire water pump engines manufactured as a certified National Fire Protection Association fire water pump engine after July 1, 2006.

For the purpose of this rule, “manufactured” means the date the owner places the order for the equipment. Based on the timeline projected for obtaining approval of the Project, the applicant expects that the engines will be ordered (and thus manufactured) in 2018.

Owners and operators of fire water pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards listed for all pollutants. For model year 2016 or later 175-horsepower (hp) engines, the limits are 2.6 grams per horsepower-hour (g/hp-hr) for CO, 3.0 g/hp-hr for non-methane hydrocarbons (NMHC) and NO_x combined, and 0.22 g/hp-hr for PM. The PEP will install a Tier 3 engine meeting these standards.

Owners and operators of non-fire pump engines must comply with the emission standards listed for all pollutants. For a model year 2016 or later engine with 750 hp or more, the limits are 2.6 g/hp-hr for CO, 4.8 g/hp-hr for NMHC and NO_x combined, and 0.15 g/hp-hr for PM. The Project will install a Tier 2 emergency generator engine meeting these standards.

Subpart KKKK Standards of Performance for Stationary Combustion Turbines.

Subpart KKKK places emission limits of NO_x and SO_2 on new combustion turbines and the associated HRSG and duct burners. For new combustion turbines firing natural gas with a rated heat input greater than 850 MMBtu/hr, NO_x emissions are limited to 15 ppm at 15 percent O_2 of useful output (0.43 pounds per megawatt-hour [lb/MWh]).

3.1.2 National Standards of Performance for New Stationary Sources -40 CFR Part 60, Subparts Db, KKKK and IIII

The NSPS program provisions limit the emission of criteria pollutants from new or modified facilities in specific source categories. The applicability of these regulations depends on the equipment size or rating; material or fuel process rate; and/or the date of construction, or modification. Reconstructed sources can be affected by NSPS as well. Applicability of Subpart KKKK to the proposed new turbine supersedes applicability of Subpart GG. The HRSG and duct burners are also subject to KKKK (they are exempt from Db). Compliance with BACT will insure compliance with the emissions limits of Subpart KKKK. The auxiliary boiler is subject to Db and will comply this standard.

SO_x emissions are limited by either of the following compliance options:

1. The operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 ng/J (0.90 lb/MWh) gross output, or

2. The operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 0.060 lbs SO_2/MMBtu heat input.

Subpart IIII is expected to apply to the proposed fire pump engine. Compliance with the EPA and CARB tiered emissions standards, and the CARB/AVAQMD ATCM for stationary CI engines, will insure compliance with IIII.

As described in the BACT section, the PEP will use a SCR system to reduce NO_x emissions to 2.0 ppm and pipeline natural gas to limit SO_2 emissions to 0.0006 pounds per MMBtu to meet BACT requirements, which ensures that the Project will satisfy the requirements of Subpart KKKK.

3.1.3 National Emission Standards for Hazardous Air Pollutants - 40 CFR Part 63

The NESHAPs program provisions limits hazardous air pollutant emissions from existing major sources of HAP emissions in specific source categories. The NESHAPs program also requires the application of maximum achievable control technology (MACT) to any new or reconstructed major source of HAP emissions to minimize those emissions. Subpart YYYY will apply to the proposed turbine. The emissions provisions of Subpart YYYY are currently subject to "stay" by EPA. Notwithstanding the foregoing, the proposed turbines are expected to comply with the emissions provisions.

3.1.4 Prevention of Significant Deterioration Program - 40 CFR Parts 51 and 52

The PSD program requires the review and permitting of new or modified major stationary sources of air pollution to prevent significant deterioration of ambient air quality. PSD applies only to pollutants for which ambient concentrations do not exceed the corresponding NAAQS. The PSD program allows new sources of air pollution to be constructed, and existing sources to be modified, while maintaining the existing ambient air quality levels in the Project region and protecting Class I areas from air quality degradation. The facility will trigger the PSD program requirements.

3.1.5 New Source Review - 40 CFR Parts 51 and 52

The NSR program requires the review and permitting of new or modified major stationary sources of air pollution to allow industrial growth without interfering with the attainment of AAQS. NSR applies to pollutants for which ambient concentrations exceed the corresponding NAAQS. The air quality analysis prepared for the AVAQMD and the CEC complies with all applicable NSR provisions.

3.1.6 Title IV - Acid Rain Program - 40 CFR Parts 72-75

The Title IV program requires the monitoring and reduction of emissions of acid rain compounds and their precursors. The primary source of these compounds is the combustion of fossil fuels. Title IV establishes national standards to limit SO_x and NO_x emissions from electrical power generating facilities. The proposed new turbines will be subject to Title IV, and will submit the appropriate applications to the air District as part of the PTC application process. The Project will participate in the Acid Rain allowance program through the purchase of SO_2 allowances. Sufficient quantities of SO_2 allowances are available for use on this Project.

3.1.7 Title V - Operating Permits Program - 40 CFR Part 70

The Title V program requires the issuance of operating permits that identify all applicable federal performance, operating, monitoring, recordkeeping, and reporting requirements. Title V applies to major facilities, acid rain facilities, subject solid waste incinerator facilities, and any facility listed by EPA as requiring a Title V permit. Title V application forms applicable to the proposed new facility will be submitted pursuant to the District Title V permitting rule timeframes.

3.1.8 CAM Rule - 40 CFR Part 64

The CAM rules require facilities to monitor the operation and maintenance of emissions control systems and report malfunctions of any control system to the appropriate regulatory agency. The CAM rule applies to emissions units with uncontrolled potential to emit levels greater than applicable major source thresholds. However, emission control systems governed by Title V operating permits requiring continuous compliance determination methods are exempt from the CAM rule. Since the project will be issued a Title V permit requiring the installation and operation of continuous emissions monitoring systems, the project will qualify for this exemption from the requirements of the CAM rule.

3.1.9 Toxic Release Inventory Program (TRI) - Emergency Planning and Community Right-to-Know Act

The TRI program as applied to electric utilities, affects only those facilities in Standard Industrial Classification (SIC) Codes 4911, 4931, and 4939 that combust coal and/or oil for the purpose of generating electricity for distribution in commerce must report under this regulation. The proposed project SIC Code is 4911. However, the proposed Project will not combust coal and/or oil for the purpose of generating electricity for distribution in commerce. Therefore, this program does not apply to the proposed Project.

3.1.10 NSPS Part 60 Subpart TTTT Greenhouse Gas Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units.

In January, 2014, the USEPA re-proposed the standards of performance regulating CO_2 emissions from new affected fossil-fuel-fired generating units, pursuant to Section 111(b) of the Clean Air Act. The final rule was published in the Federal Register on August 3, 2015, and will become effective on or about October 3, 2015. The rule applies to new sources such as PEP constructed after January 8, 2014. The rule establishes separate standards for two types of sources, i.e., stationary combustion turbines firing natural gas, and electric utility steam generating units (generally firing coal). The final CO_2 standard for base loaded combustion turbines is 1000 lbs CO2/MWh- gross. The PEP facility is expected to readily comply with this standard.

3.1.11 National Emission Standards for Hazardous Air Pollutants (Parts 61 and 63)

There are no Part 61 standards applicable to the facility operations. As discussed in Section 5.0 and shown in the emission calculations in Appendix A, the Project Hazardous Air Pollutant (HAP) emissions are well below the thresholds for the NESHAP programs (i.e., 10 tpy of any single HAP and 25 tpy of all HAP combined) and, hence, 40 CFR Part 63 standards are not applicable to this Project.

3.1.12 Chemical Accident Prevention (Part 68)

The use of 19.5 percent concentration ammonia for the Project exempts the Project from Federal RMP applicability. The facility will be subject to California's Accidental Release Prevention Program for aqueous ammonia storage and use, which is similar to the Federal RMP program.

3.1.13 Title V, Facility Operating Permits (Part 70)

The Project is required to comply with the Federal Operating Permits Program, also known as Title V. As required by AVAQMD rules, the Project will comply with these requirements by submitting a Title V application within 12 months after starting commercial operation of the facility.

3.1.14 Title IV, Acid Rain (Part 72)

The Project is also required to comply with the Acid Rain requirements (Title IV). Since the AVAQMD has received delegation for its Title V permit program, the Applicant will secure a Title V permit that imposes the necessary requirements for compliance with the Title IV Acid Rain provisions from the AVAQMD.

3.1.15 Federal Conformity

The general conformity analysis thresholds are as follows in accordance with Code of Federal Regulations (40 CFR Parts 6 and 51):

NO_x – 50 tons per year

VOCs – 50 tons per year

CO – 100 tons per year

SO_x – 100 tons per year

PM10 – 100 tons per year

PM2.5 – 100 tons per year

Emissions from the construction phase are not estimated to exceed the conformity levels noted above. Emissions from the operational phase are subject to the AVAQMD NSR and the EPA PSD permitting provisions, and as such, are exempt from a conformity determination or analysis.

Section 4 ENVIRONMENTAL SETTING

4.1 PROJECT LOCATION

The PEP will be located in the Antelope Valley, which forms the western tip of the Mohave Desert. The topography of the area is characterized as high desert with very little variation in terrain until the desert abuts the mountain ranges. The project site is located about 10 kilometers (km) northeast of the San Gabriel Mountains, which separate Antelope Valley from the City of Los Angeles, and 50 km southeast of the Tehachapi Mountains, which separate Antelope Valley from the San Joaquin Valley. The proposed project site is located in northern Los Angeles County just west-northwest of the Palmdale-Air Force Plant 42 Complex. The location is in the northern portion of the city of Palmdale and near the southern boundary of the city of Lancaster.

The PEP site location is located on an approximately 50-acre undeveloped parcel west of the northwest corner of U.S. Air Force Plant 42, and east of the intersection of Sierra Highway and East Avenue M. The PEP address is 950 East Avenue M, Palmdale California. The Universal Transverse Mercator (UTM) North American Datum (NAD) 83, Zone 11 coordinates are 398,600 meters east and 3,833,700 meters north. The site elevation is approximately 2,512 feet above mean sea level (amsl). Figures * and * present the location of the proposed project.

4.2 CLIMATE AND METEOROLOGY

The proposed site in the Palmdale, California area, within the north-eastern portion of Los Angeles County, experiences the following climate and meteorology patterns.

The Mojave Desert Air Basin (MDAB) is an assemblage of mountain ranges interspersed with long broad valleys that often contain dry lakes. Many of the lower mountains which dot the vast terrain rise from 1,000 to 4,000 feet above the valley floor. Prevailing winds in the MDAB are out of the west and southwest. These prevailing winds are due to the proximity of the MDAB to coastal and central regions and the blocking nature of the Sierra Nevada Mountains to the north. Air masses pushed onshore in southern California by differential heating are channeled through the MDAB. The MDAB is separated from the southern California coastal and central California valley regions by mountains (highest elevation approximately 10,000 feet), whose passes form the main channels for these air masses. The Antelope Valley is bordered in the northwest by the Tehachapi Mountains, separated from the Sierra Nevada Mountains in the north by the Tehachapi Pass (3,800 ft elevation). The Antelope Valley is bordered in the south by the San Gabriel Mountains, bisected by Soledad Canyon (3,300 ft). The Mojave Desert is bordered in the southwest by the San Bernardino Mountains, separated from the San Gabriel's by the Cajon Pass (4,200 ft). A lesser channel lies between the San Bernardino Mountains and the Little San Bernardino Mountains (the Morongo Valley).

During the summer the MDAB is generally influenced by a Pacific Subtropical High cell that sits off the coast, inhibiting cloud formation and encouraging daytime solar heating. The MDAB is rarely influenced by cold air masses moving south from Canada and Alaska, as these frontal systems are weak and diffuse by the time they reach the desert. Most desert moisture arrives from infrequent warm, moist and unstable air masses from the south. The MDAB averages between three and seven inches of precipitation per year (from 16 to 30 days with at least 0.01 inches of precipitation). The MDAB is classified as a dry-hot desert climate, with portions classified as dry-very hot desert, to indicate at least three months have maximum average temperatures over 100.4° F.

The climatic pattern for the Project region is a typical desert climate within the Mediterranean climate classification. The warmest month for the region is typically July, with December being the coldest month. The month with the highest precipitation is usually February. The eastern Mojave Desert region experiences a large number of days each year with sunshine, generally 345+ days per year. The region also traditionally experiences excellent visibility, i.e., greater than 10 miles or more 95 percent of the time.

Representative climatic data for the Project Area was derived from the Palmdale AF Plant 42 Station (Period of Record 1998-2008) located to the west of the Project Site. A summary of data from this site indicates the following:

- Average annual maximum daily temperature: 77.1°F
- Average annual minimum daily temperature: 47.2°F
- Average temperature (annual): 64°F
- Extreme maximum temperature: 113°F
- Extreme minimum temperature: 10°F
- Mean annual precipitation: 5.25 inches

Air quality is determined primarily by the type and amount of pollutants emitted into the atmosphere, the nature of the emitting source, the topography of the air basin, and the local meteorological conditions. In the Project Area, inversions and light winds can result in conditions for pollutants to accumulate in the region. Annual and quarterly wind roses for the Palmdale Air Force Plant 42 Automated Surface Observing System (ASOS) weather station for the period 2010-2014 are presented in Appendix C. The wind pattern in the project area is primarily from the southwest (south through west-northwest). Calm winds occur approximately 3.82% of the time on an annual average basis.

4.3 LAND USE AND POPULATION

The proposed PEP would be located on a 50-acre site that is currently vacant and undeveloped, and is part of a 613.4-acre property owned by the city of Palmdale. Existing land uses immediately adjacent to the proposed PEP site include:

North: Undeveloped land and heavy industrial uses;
East: Air Force Plant 42 (Plant 42);
South: Plant 42; and
West: Undeveloped land owned by the city of Palmdale and water storage tanks that would be used for the proposed potable water pipeline.

The area immediately surrounding the project site is primarily dominated by industrial development with several scattered residences north of the proposed project site. The closest residence is in the city of Lancaster located approximately 1,500 feet northwest of the closest boundary of the project site. Other sensitive receptors include the Lancaster Adult Day Center which is approximately 1,800 feet northwest of the closest boundary of the project site.

Plant 42 surrounds the south and east boundaries of the proposed project site and is operated by Lockheed, Rockwell International, Northrop, and Nero; a portion is leased to the LA/Palmdale Regional Airport. The Plant 42 site is over 6,600 acres and supports facilities for production, engineering, final assembly, and flight testing of high performance aircraft, as well as commercial operations. The proposed project site is located on the south side of East Avenue M approximately 1.95 miles east of State Route (SR) 14/138. The site is bounded by Challenger Way to the east, East Avenue M to the north, and Sierra Highway to the west. Access to the site during construction and operation would be available from a new street and signalized intersection at 10th Street that would be developed by the city of Palmdale.

Population centers located within the county of Los Angeles include the city of Lancaster and the unincorporated communities of Quartz Hill to the north; Lake Los Angeles to the east, Acton to the south; and Leona Valley to the west. The nearest sizeable cities to the project site include Santa Clarita (25 miles west), Adelanto (39 miles east), Victorville (40 miles east), Hesperia (41 miles east) and Apple Valley (44 miles east), all of which are located in San Bernardino county. The nearest residential area is located approximately one mile north of the plant site.

Table 4-1 shows the historical and projected population data for the study area.

Table 4-1
Historical and Projected Populations

Area	2000 Population	2010 Population	2020 Population
Los Angeles County	9,578,960	10,718,007	11,501,884
San Bernardino County	1,709,434	2,059,420	2,397,709
Kern County	665,519	1,086,113	1,352,628
Source: PHPP AFC, Socioeconomic Section, 2009			

The estimated population within a 6-mile radius search area of the project site is approximately 226,068 individuals.

4.4 EXISTING AIR QUALITY

4.4.1 Background Air Quality

In 1970, the United States Congress instructed the USEPA to establish standards for air pollutants, which were of nationwide concern. This directive resulted from the concern of the impacts of air pollutants on the health and welfare of the public. The resulting Clean Air Act (CAA) set forth air quality standards to protect the health and welfare of the public. Two levels of standards were promulgated—primary standards and secondary standards. Primary national ambient air quality standards (NAAQS) are "those which, in the judgment of the administrator [of the USEPA], based on air quality criteria and allowing an adequate margin of safety, are requisite to protect the public health (state of general health of community or population)." The secondary NAAQS are "those which in the judgment of the administrator [of the USEPA], based on air quality criteria, are requisite to protect the public welfare and ecosystems associated with the presence of air pollutants in the ambient air." To date, NAAQS have been established for seven criteria pollutants as follows: SO_2, CO, ozone, NO_2, PM10, PM2.5, and lead. Currently there is no NAAQS for TSP, and attainment designations are no longer based on TSP. TSP is included in the PSD analysis as a regulated pollutant only. As such, for the remainder of this application and analysis the term PM10/2.5 will be considered to include TSP.

Each federal or state AAQS is comprised of two basic elements: (1) a numerical limit expressed as an allowable concentration, and (2) an averaging time which specifies the period over which the concentration value is to be measured. Table 4-2 presents the current federal AAQS.

Table 4-2
Federal Ambient Air Quality Standards

Pollutant	Averaging Time	National Standards Concentration
Ozone	1-hour	-
	8-hour	0.075 ppm (147 µg/m³) (3-year average of annual 4th-highest daily maximum)
Carbon Monoxide	8-hour	9 ppm (10,000 µg/m³)
	1-hour	35 ppm (40,000 µg/m³)
Nitrogen dioxide	Annual Average	0.053 ppm (100 µg/m³)
	1-hour	0.100 ppm (188 µg/m³) (3-year average of annual 98th percentile daily max's)
Sulfur dioxide	Annual Average	-
	24-hour	-
	3-hour	0.5 ppm (1,300 µg/m³)
	1-hour	0.075 ppm (196 µg/m³) (3-year average of annual 99th percentile daily max's)
Respirable particulate matter (10 micron)	24-hour	150 µg/m³
	Annual Arithmetic Mean	-
Fine particulate matter (2.5 micron)	Annual Arithmetic Mean	12.0 µg/m³ (3-year average)
	24-hour	35 µg/m³ (3-year average of annual 98th percentiles)
Sulfates	24-hour	-
Lead	30-day	-
	3 Month Rolling Average	0.15 µg/m³

Source: CARB website, table updated 6/4/13
Notes:
µg/m³ = micrograms per cubic meter
ppm = parts per million

Table 4-3 presents the AVAQMD attainment/nonattainment status. The nearest representative air quality monitoring station is the Lancaster Division Street site. The monitoring station is 2.5 miles north from the PEP in the city of Lancaster, which has an approximate population of 160,000 and is near the Sierra Highway (110 meters), the Antelope Valley Freeway (SR-14) (4 kilometers), Division Street (50 meters), and the Southern Pacific Railway (80 meters). This monitoring station collects NO_2, CO, PM10, PM2.5 and O_3 data. Based on the siting of this station in a very urban setting, along with its close proximity to roadways, it would provide a conservative estimate of background air quality. This site also satisfies the EPA requirements for sitting NO_2 and O_3 monitoring stations near well-traveled roadways. This urban location would also be considered conservative for background data.

Ambient monitoring data for these sites for the most recent three-year period (2012-2014) are summarized in Table 4-4, Air Quality Monitoring Data. Data from these sites are a reasonable representation of background air quality for the Project Site and impact area.

Table 4-3
AVAQMD Attainment Status

Pollutant	Averaging Time	Federal Status
Ozone	1-hr	Nonattainment
Ozone	8-hr	Nonattainment
CO	All	Attainment
NO_2	All	Unclassified/Attainment
PM10	All	Unclassified
PM2.5	All	Unclassified/Attainment
Source: CARB website status maps, 3/2015. AVAQMD CEQA Guidelines, 3/2015.		

Table 4-4 presents a summary of the air quality monitoring data representative of the project region.

Table 4-4
Air Quality Monitoring Values for 2012-2014

Pollutant	Site	Averaging Time	2012	2013	2014
Ozone, ppm	Lancaster	8 Hr Max* NAAQS	0.095	0.094	0.087
		24-Hr H2H NAAQS	38	74	80
PM10, µg/m^3	Lancaster	24 Hr 98th% NAAQS	14**	11	28
		Annual Mean NAAQS	5.4**	5.8	7.2
		1 Hr 98th% NAAQS	46	44	40
PM2.5, µg/m^3	Lancaster	Annual Mean	9	8	8
		1 Hr Max* NAAQS	1.9	1.9	N/A
NO_2, ppb	Lancaster	8 Hr Max* NAAQS	1.4	1.2	N/A
		8 Hr Max* NAAQS	1.4	1.2	N/A

		8 Hr Max* NAAQS	1.4	1.2	N/A
CO, ppm	Lancaster	8 Hr Max* NAAQS	1.4	1.2	N/A
		8 Hr Max* NAAQS	1.4	1.2	N/A

*For 1-hour and 8-hour ozone and CO, the maximum measured background concentrations were used for the NAAQS assessment. Normally, the NAAQS assessments are based on lesser concentrations such as the second-highest measured concentration each year for 24-hour PM10 and 1-hour and 8-hour CO, and the fourth-highest daily maximum 8-hour concentration averaged over three years for the ozone NAAQS.

**Incomplete data for year (does not meet ARB/USEPA criteria).

Source: USEPA AirData website (www.epa.gov/airdata) except for annual PM10 and NO_2, taken from ARB iADAM Top -4 website (http://www.arb.ca.gov/adam/topfour/topfour1.php). Due to periods of suspect or invalid data in the USEPA AirData for 2014, Lancaster CO data were not used.

Table 4-5 shows the background air quality values based upon the data presented in Table 4-4. The background values represent the appropriate values for the NAAQS according to the format of the standard as noted below.

Table 4-5
Background Air Quality Data

Pollutant and Averaging Time	Background Value
Ozone – 8-hour Maximum NAAQS	0.095 ppm (187 µg/m^3)
PM10 – 24-hour High Second-High NAAQS	80 µg/m^3
PM2.5 – 3-Year Average of Annual 24-hour 98th Percentiles NAAQS	18 µg/m^3
PM2.5 – 3-Year Average of Annual Values NAAQS	6.1 µg/m^3
CO – 1-hour Maximum NAAQS	1.9 ppm (2176 µg/m^3)
CO – 8-hour Maximum NAAQS	1.4 ppm (1603 µg/m^3)
NO_2 – 3-Year Average of Annual 1-hour 98th Percentile Daily Maxima NAAQS	0.043 ppm (81 µg/m^3)
NO_2 – Annual Maximum NAAQS	0.008 ppm (15.1 µg/m^3)

* The 3rd highest seasonal NO_2 concentrations for each hour, averaged over the past three years, were used in the cumulative multisource inventory 1-hour NO_2 NAAQS analyses.

For conversion from the ppm measurements to µg/m^3 concentrations typically required for the modeling analyses, used: µg/m^3 = ppm x 40.9 x MW where MW = 48, 28, and 46, for ozone, CO, and NO_2, respectively.

4.5 SOILS AND VEGETATION

The soils and vegetation analysis presented herein was updated, as needed, from the following source: *Palmdale Hybrid Power Plant, PSD Application, Supplemental Information, Section 5.0, AECOM, June 2010*. As the soils and vegetation in the project area have remained unchanged from the previous application date, the use of the analysis, with updates to reflect PEP, is valid.

The original project included approximately 333 acres of total disturbance. The Modified Project has eliminated the solar components but is retaining the location for the power generating equipment thereby reducing the total disturbance to 70 acres (20 acres of temporary construction laydown area and 50 acres permanent area). The United States Fish and Wildlife Service (USFWS) previously consulted on the original project and issued a letter determining that the project would not likely adversely affect federally protected species and therefore no Biological Opinion and Incidental Take Statement would be required. Since the Modified Project involves the same land and there have been no new federally listed species known to occur in the project vicinity, the previous determination by the USFWS is still applicable. Therefore, no additional Biological Assessment documentation is proposed or required to support this PSD application for the Palmdale Energy Project.

4.5.1 Regulatory Overview and Background

The PSD regulations codified at 40 Code of Federal Regulations (CFR) §52.21(o) require that an analysis of the impact to soils and vegetation of significant commercial or recreational value that would occur as a result of the project be conducted. The regulation indicates that the owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value. The EPA guidance document for soils and vegetation, *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (EPA 450/2-81-078, OAQPS, Research Triangle Park, NC. December 12, 1980)* was the basis for the analysis previously submitted in the PSD application submitted in April 2009. The EPA guidance document establishes the air pollutant concentrations that are generally viewed to be protective of soils and vegetation having significant commercial or recreational value, including agricultural crops, based on a broad review of pertinent scientific literature.

During a conference call in March 2010, EPA Region 9 requested that the PHPP analysis of soils and vegetation impacts be supplemented pursuant to the following Environmental Appeals Board case: *In re: Indeck-Elwood, LLC*; PSD Appeal No. 03-04; PSD Permit No. 197035AAJ (decided September 27, 2006) (“Indeck”). The Indeck case contemplates the need for additional analysis beyond a “screening analysis” with respect to soil and vegetation for a PSD application. Accordingly, the Indeck case was reviewed for applicability to the PHPP (and PEP) application. As an initial matter, key aspects of the Indeck case are not directly applicable. For example, PEP, like PHPP is a clean, state-of-the-art, gas-fired combined-cycle facility located within developed city limits, while the Indeck facility is a proposed large-scale coal-fired power plant located approximate to a prairie reserve of national importance.

Although a more rigorous analysis is provided herein, we note that the PEP will have substantially lower air quality impacts than would a coal-fired power plant. The key holding of Indeck is that an agency should consider requiring more than a "screening analysis" to evaluate soil and vegetation impacts to the extent that the 1990 New Source Review (NSR) Manual would result in a different significance conclusion. In particular, the Indeck case contemplates an inventory of applicable soils and vegetation and consideration of site-specific effects where appropriate to identify potential impacts. *See*, *e.g.,* Indeck, pp. D.4-5 and D.11-12.

Following the review of Indeck, AECOM supplemented the PHPP (now PEP) soils and vegetation analysis to ensure the analysis reflected the methodology in the 1990 NSR Manual (EPA, 1990). Although AECOM believed the prior submittal achieved the standard in the 1990 NSR Manual, they provided additional information in this submittal to better demonstrate consistency. The guidance in the 1990 NSR Manual, Section II.C Soils and Vegetation Analysis, is brief, less than one page long. The key components of the analysis are to develop an inventory of the soils and vegetation types with commercial or recreational value found in the area, and to analyze the impacts from *regulated pollutants* that are proposed to be emitted by the facility. This requirement only applies to regulated pollutants that are to be emitted from the facility in *significant amounts*. While an example related to fluorides is provided in Section II.C, an additional example analysis provided in Section III.C of the NSR Manual clearly states "…the sensitivity of the various soils and vegetation types to each of the applicable pollutants that will be emitted by the facility *in significant amounts*." (pg D.11, emphasis added).

PEP will only have significant emissions of NOx, VOC, CO, and PM/PM10/PM2.5, and hence the fact that the prior PHPP analysis only addressed modeled impacts of these pollutants is appropriate for the PEP. As a clean, natural-gas fired project, PEP will not emit any of the other regulated, non criteria pollutants listed in Table A.4 of the NSR Manual in significant amounts (also summarized in Chapter 2.0 above).

4.5.2 Extent of the Analysis

The prior PSD soils and vegetation analysis conducted for the PHPP was performed for three pollutants: NOx, CO and PM10. The maximum modeled concentrations for PHPP normal operations are found in Table 6-6 of the 2009 PSD application. As shown in that table, the predicted annual NOx, as well as the 1-hour and 8-hour CO impacts did not exceed the EPA Significant Impact Level (SIL). These results are identical for the PEP. Both the 24-hour and the annual PM10 impacts exceeded the EPA SIL for PHPP while only the 24-hour PM10 SIL was exceeded for the PEP. The peak PM10 impact occurred at a distance of less than 400 meters from the project boundary, in a small area on the USAF Plant 42 property in a small area northeast of the power block. Therefore, the maximum extent of the SIA for these pollutants encompasses an approximately 400 meter radius around the combined-cycle facility, although PM10 impacts only occurred in a small area near developed industrial facilities. The PEP has identical results. Because pollutant concentrations associated with both projects are highest within this area, the analysis for the SIA provide conservative pollutant concentration values in regard to the regional facility impact. In addition, the SIA for both projects includes land use, terrain, soil type, and flora that is typical of the Antelope Valley in the western Mojave Desert. The SIA circle encompasses industrial land, undeveloped land, military land/airport, and commercial/light industrial properties.

In addition to analyzing impacts within the SIA, soils and vegetation types with respect to the five sensitive Class II areas identified in Section 4 of the PHPP PSD permit application (i.e., three state parks, one woodland and one wilderness area located within 50 km of the proposed Project) were discussed. Due to the substantial distance beyond the SIA, pollutant impacts in these areas would be significantly lower than those in the area of maximum impact within the SIA for both projects. The supplemental soils and vegetation analysis provides additional information on the vegetation and soils inventory in the project area and examines the potential effects of NOx, CO and PM10/PM2.5 within the project area on these soils and vegetation types.

4.5.3 Vegetation Types

Some agricultural crops are grown within the vicinity of the PEP site. As noted in the AFC, these crops include primarily commercial alfalfa and onion production. Agricultural/orchard lands lie about two miles northeast and east of the power plant site

Within the defined 400 m SIA, the vegetation communities on the PEP site and immediate surrounding area can generally be classified as desert scrub, consisting primarily of perennial shrub species with an herbaceous understory of annuals that grows during the wetter and cooler spring months, as well as Joshua tree woodland. Focused botanical surveys of the proposed project areas (power plant site and laydown area) and perimeters of buffer zones conducted in 2006 and 2008 did not reveal the presence of any federal, state, or California Native Plant Society (CNPS)-list 1 or 2 sensitive plant species. An additional survey conducted in early and late spring of 2010, limited to the PHPP power plant site, laydown area, and reclaimed water supply pipeline and buffer areas around these project components, also did not detect any such listed species. This is applicable to the PEP.

Plant species protected by the City of Palmdale's Native Desert Vegetation Ordinance were observed during these surveys. In particular, the Joshua tree (Yucca brevifolia) currently exists throughout the project site, although all of these trees on the PEP site will be removed at the start of construction. The closest state parks or sanctuary are located approximately 14 miles east-north-east of the proposed Project, i.e., Antelope Valley Indian Museum State Park and Saddleback Butte State Park (see Section 4).

The vegetation at Saddleback Butte State Park includes spring wildflowers, creosote bushes, cholla cacti and Joshua trees at lower elevations. The Antelope Valley Indian Museum State Park has vegetation indigenous to the area. The Antelope Valley California Poppy State Reserve is on the state's most consistent poppy-bearing land. Other wildflowers growing there include owl's clover, lupine, goldfield, cream cups, coreopsis, lacy phacelia, Davy Gilia, rabbit brush, red maids, and green grasses. The Arthur B. Ripley Desert Woodland State Park protects a major stand of native Joshua trees and junipers. This park is very near the Antelope Valley California Poppy Reserve State Natural Reserve and has similar wildflowers growing there. The Sheep Mountain Wilderness has grazing land, mining activities and is used for water-related recreational use. All of these areas are quite distant to PEP, and hence given that the PEP emissions are very low and the maximum impacts occur in the immediate vicinity of the power plant, there would be only de minimus impacts expected to the vegetation in these parks.

No designated critical habitat areas for federally-listed species occurs within 20 miles of the power plant site. The closest Los Angeles County Significant Ecological Areas is the Little Rock Wash, which occurs about five miles to the east of PEP power plant site.

The analysis of the air pollutants on vegetation submitted with the April 2009 PSD application was performed using the EPA 1980 screening document. There is also a screening document developed by the U.S. Department of Agriculture (USDA) entitled, *A Screening Procedure to Evaluate Air Pollution Effects in Region 1 Wilderness Areas, 1991*. The 1991 document includes plant species specific pollutant concentration thresholds for western U.S. species, as well as other information that complements the 1980 EPA guidance. The two referenced guidance documents have been reviewed to identify the most appropriate threshold values (if available) for this region based upon the species identified that have significant commercial or recreational value.

Although the reference documents do not provide values for all of the identified species or pollutants, they do provide information about the alfalfa and onion field crops which are the primary crops in the vicinity of the project area. Based upon the information provided in Appendix B in *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals*, the alfalfa were found to be rated as “sensitive” to NO2 and the onions were found to be “resistant” to NO2. The “sensitive” rating means that the lowest damage threshold is applied. Based upon this information, the proposed impact analysis was based upon compliance with the threshold levels for “sensitive” vegetation that are identified in Table 3.1 of *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals*. These criteria are shown for the applicable pollutants (CO and NOx) in Table 6-17 of the April 2009 PSD application. In that table, the total modeled air concentrations for the proposed project plus ambient background concentrations are compared to the criteria to evaluate impacts. The total concentrations are well below the significance criteria for each pollutant and averaging time. Since no thresholds were exceeded, there is no potential for adverse impact on vegetation. This approach uses the most stringent level of damage threshold to assure conservative results, thus additional evaluation of impacts of air pollutants to vegetation is unnecessary.

4.5.4 Soil Types

Soils on and around the PEP include Adelanto coarse sandy loam, Cajon loamy sand, and Cajon loamy fine sand. Section 5.12 Soils of the PHPP AFC includes a complete list of the soil types found in Los Angeles County and the Antelope Valley Area.

4.5.5 Nitrogen Deposition

In addition to the ambient pollutant exposure levels (that was evaluated in the March 2009 PSD application and updated here), plants have the potential to be affected by intake of air pollutants that have deposited and subsequently accumulated in the soil. Compared to the amount of published information on the effects of atmospheric pollution on plants and animals, relatively little has been reported on their effects on soils. Often the effect on soils can be seen in plants and animals such that the impacts to soil are secondary. For instance, if contaminated soil causes vegetative damage, the result could be increased erosion, increase in solar radiation reaching the ground, higher soil temperature and moisture stress. In agricultural and populated areas, intentional human actions taken to improve soils and assist vegetation growth, such as fertilization and application of insecticides, tend to have a much more direct and profound effect on soils than airborne pollutants. Nitrogen can be added to soil as a result of atmospheric deposition. Nitrogen deposition in soil can have beneficial effects to vegetation if they are currently lacking these elements. At levels above plant requirements, gaseous emission impacts on soils can cause acidic conditions to develop. Soil acidification and eutrophication can occur as a result of atmospheric deposition of nitrogen.

To calculate nitrogen depositional impacts from operation of the project, the *Near Field Nitrogen Deposition Modeling Guidance (November 2013)* was followed. The primary purpose of any screening analysis is to produce a preliminary or conservative estimate of potential impacts (USEPA, 2005). Treatment of emissions as inert NO_2 likely will underestimate near-field deposition of nitrogen because the deposition velocities for NO and NO_2 are relatively low in comparison to other nitrogen species. While most emissions are initially introduced into the atmosphere as NO and NO_2 (NO_x), chemical processes in the atmosphere can rapidly convert to other nitrogen species with higher deposition velocities. Nitric acid (HNO_3) is of greater concern because it has one of the highest deposition velocities of various nitrogen species. Using non-reactive (no chemistry) dispersion models such as AERMOD to complete a deposition analysis by assuming all conservative of NO_x emissions into depositional nitrogen provided a conservative methodology.

A threshold at which harmful effects from nitrogen deposition on plant communities has not been firmly established. However, a value of 5 kilograms per hectare per year (kg/ha/yr) is often used for comparing nitrogen deposition among plant communities. Research conducted in the South San Francisco Bay Area indicates that intensified annual grass invasions can occur in areas with nitrogen deposition levels of 11–20 kg/ha/yr, with limited invasions at levels of 4–5 kg/ha/yr (Weiss 2006a and Weiss 2007, as cited in CEC 2007). Using a depositional value of 0.05 m/s, the levels of nitrogen deposition in the area around the project site are estimated at 0.419 kg/ha/yr, far below levels necessary to cause adverse effects.

Furthermore, the level of nitrogen deposition from the PEP on plant-available nitrogen would actually be less than the calculated amount because the deposition will be distributed in small amounts during the year and not all of the nitrogen added to the soil during each deposition event is available for plant use because of losses associated with soil processes. Therefore, it is unlikely that there would be significant impacts to biological resources from nitrogen deposition.

Particulate emissions will be controlled by inlet air filtration and use of natural gas. The deposition of airborne particulates (PM10 and PM2.5) can affect vegetation through either physical or chemical mechanisms. Physical mechanisms include the blocking of stomata so that normal gas exchange is impaired, as well as potential effects on leaf adsorption and reflectance of solar radiation. Information on physical effects is scarce, presumably in part because such effects are slight or not obvious except under extreme situations (Lodge et al., 1981). Studies performed by Lerman and Darley (1975) found that particulate deposition rates of 365 g/m^2/year caused damage to fir trees, but rates of 274 g/m^2/year and 400 to 600 g/m^2/year did not damage vegetation at other sites.

The maximum annual predicted concentration for PM10 from the PEP is 0.723 µg/m^3. Assuming a deposition velocity of 2 cm/sec (worst-case deposition velocity, as recommended by the California Air Resources Board [CARB]), this concentration converts to an annual deposition rate of 0.456 g/m^2/yr, which is several orders of magnitude below that which is expected to result in injury to vegetation (i.e., 365 g/m^2/year). Using an average deposition rate across the modeling domain, the total deposition becomes 0.042 g/m^2/yr. The addition of the maximum predicted annual particulate deposition rate for the PEP to the maximum background concentration of 28.3 µg/m^3, measured at the nearest monitoring station yields a total estimated particulate deposition rate of 17.9 g/m^2/yr, utilizing the 2 cm/sec factor. This total is still less than levels expected to result in plant injury.

The primary chemical mechanism for airborne particulates to cause injury to vegetation is by trace element toxicity. Many factors may influence the effects of trace elements on vegetation, including temperature, precipitation, soil type, and plant species (USFWS, 1978). Trace elements adsorbed to particulates emitted from power plant emissions reach the soil through direct deposition, the washing of plant surfaces by rainfall, and the decomposition of leaf litter. Ultimately, the potential toxicity of trace elements that reach the root zone through leaching will be dependent on whether the element is in a form readily available to plants. This availability is controlled in part by the soil cation exchange capacity, which is determined by soil texture, organic matter content, and the kind of clay present. Soil pH is also an important influence on cation exchange capacity; in acidic soils, the more mobile, lower valence forms of trace metals usually predominate over less mobile, higher valence forms. The silty clay and clay soils in the CCGS project area will have a lower potential for trace element toxicity from the comparatively high soil pH commonly found in local soils.

Perhaps the most important consideration in determining toxicity of trace elements to plants relates to existing concentrations in the soil. Several studies have been conducted relating endogenous trace element concentrations to the effects on biota of emissions from model power plants (Dvorak et al., 1977; Dvorak and Pentecost et al., 1977; Vaughan et al., 1975). These studies revealed that the predicted levels of particulate deposition for the area surrounding the model plant resulted in additions of trace elements to the soil over the operating life of the plant that were, in most cases, less than 10 percent of the total existing levels. Therefore, uptake by vegetation could not increase dramatically unless the forms of deposited trace elements were considerably more available than normal elements present in the soil.

4.5.6 Soil Acidification

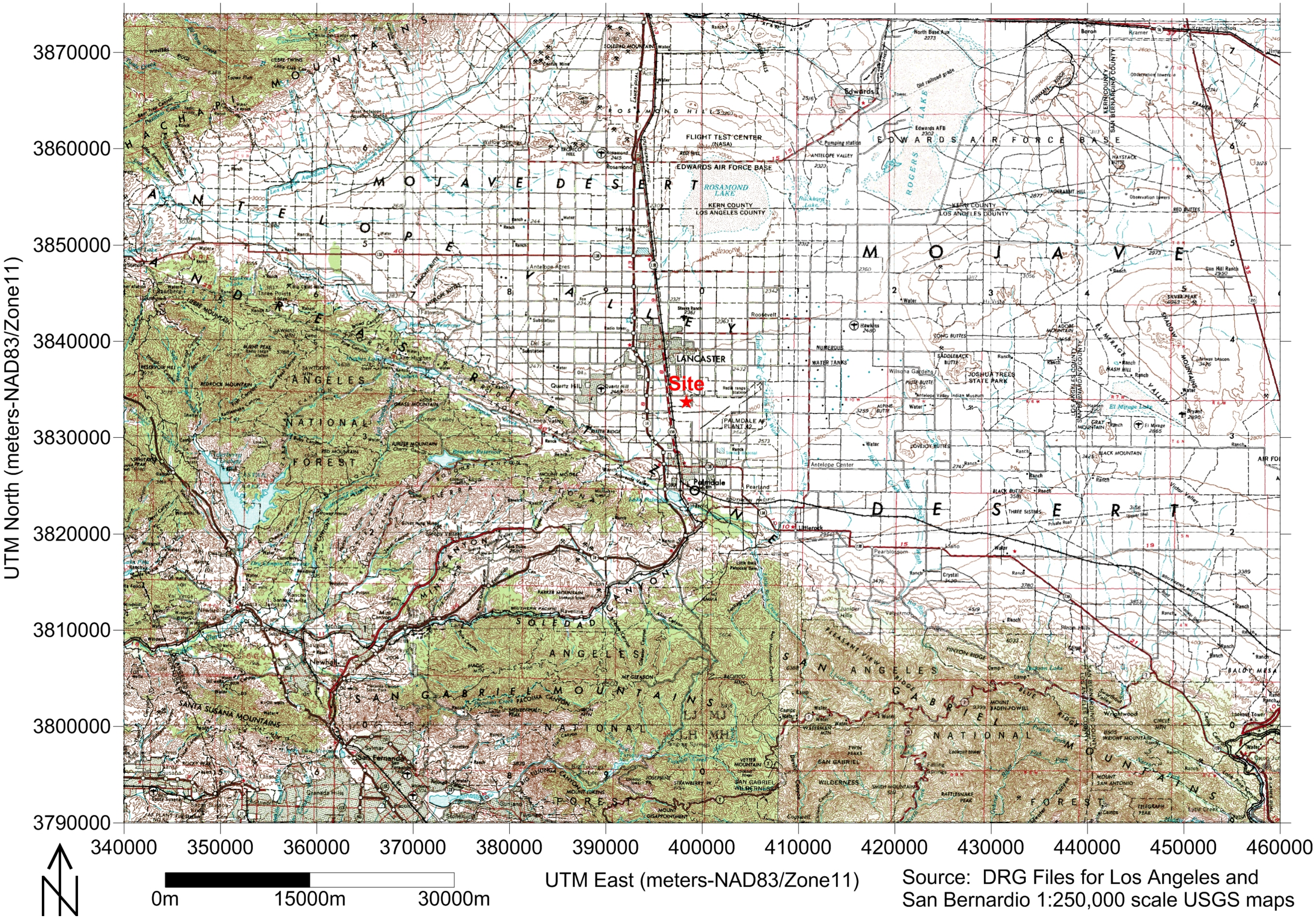
Nitrogen deposition on proximal soils is expected to occur over time as a result of PEP operations. As noted above, nitrogen deposition acts as a plant nutrient that can benefit soils, especially soils such as sandy loam that exists in the project area. However, this soil amendment can also be detrimental where it benefits non-native plants competing with native vegetation important to herbivores like the tortoise. For PEP, no desert tortoises were found in the vicinity of the power plant. Also no sensitive vegetative communities have been identified in the vicinity of PEP that would be expected to be negatively impacted by nitrogen deposition.

4.5.7 Soil Eutrophication

Eutrophication is an increase in the concentration of chemical nutrients in an ecosystem to an extent that increases the primary productivity of the ecosystem. Atmospheric deposition of nitrogen can facilitate eutrophication of the soil and vegetation community.

A measure of the existing ambient deposition (wet + dry) in the area was obtained from the most representative monitors (Death Valley and Joshua Tree) in the CASTNET monitoring network (EPA web site). Death Valley background deposition is only based on wet deposition data and is 0.272 kg/ha/yr for 2013. For Joshua Tree, the most recent data is for 2013 and is 2.152 kg/ha/yr (wet + dry). No screening thresholds to evaluate soil eutrophication were identified. Since the PEP incremental annual nitrogen is expected to be very small (e.g., less than 1 percent of the ambient measured value), the effects of deposition on eutrophication is considered to be insignificant.

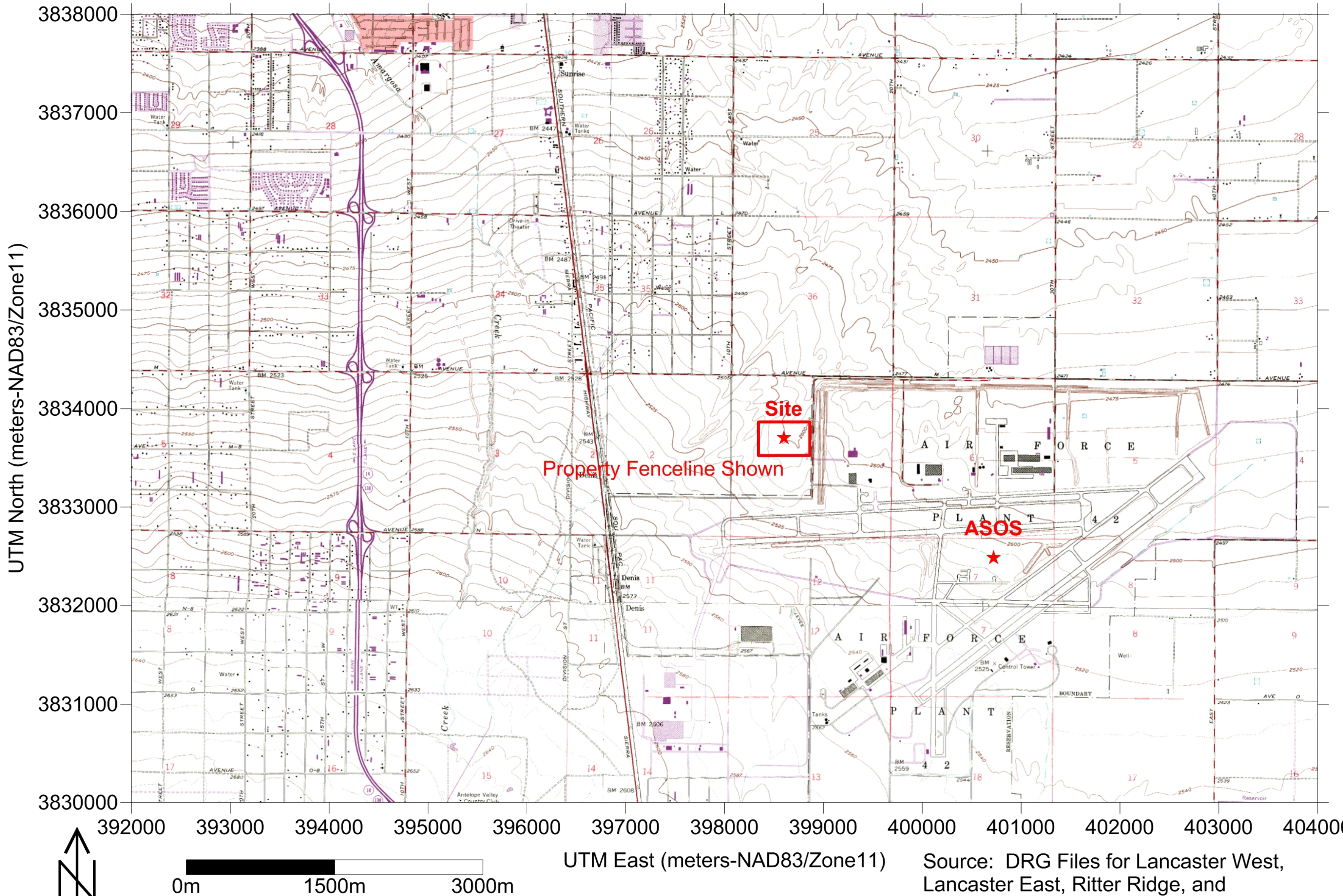
Figure 4-1
Palmdale Regional Map



Source: DRG Files for Los Angeles and San Bernardio 1:250,000 scale USGS maps

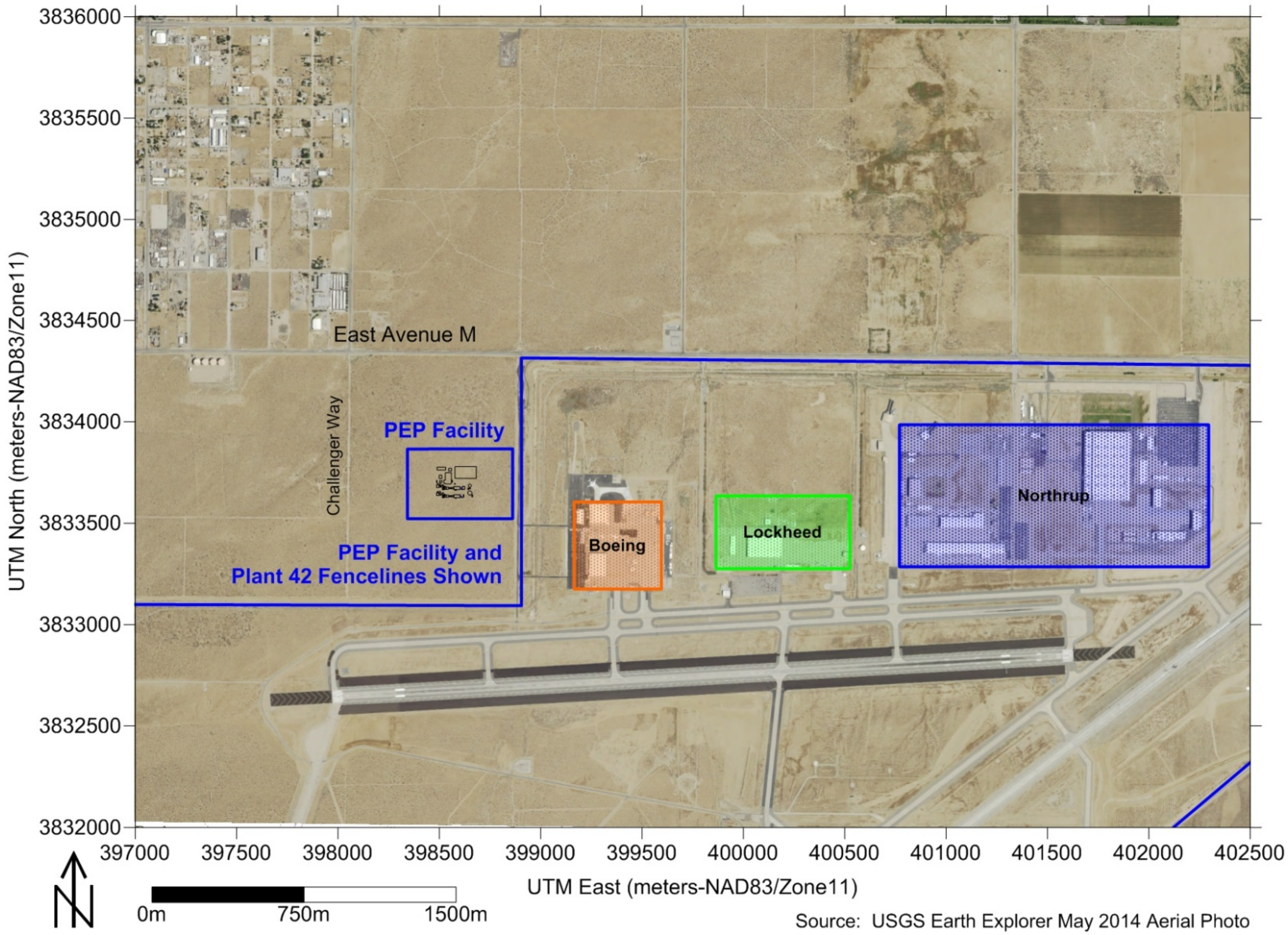
Figure 4-2

PEP Site Vicinity



Source: DRG Files for Lancaster West, Lancaster East, Ritter Ridge, and Palmdale 1:24,000 scale (7.5') USGS maps

Figure 4-3
PEP Site Vicinity



Source: USGS Earth Explorer May 2014 Aerial Photo

Section 5 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

This section presents the required best available control technology (BACT) analyses for the Palmdale Energy Project (PEP). Appendix A and F contains support data for this analysis, i.e., emissions calculations, BACT summary listings, cost analysis data, etc.

5.1 APPLICABILITY

The Federal Prevention of Significant Deterioration regulations (40 CFR 52.21) require that BACT be applied for each pollutant which is major, i.e., in the case of a combined cycle power plant the major source threshold level is 100 tons per year. In addition, once a source is determined to be "major" for one or more PSD pollutants, then any remaining pollutants which are emitted in quantities in excess of the "significant emissions rates (SERs)" are also subject to PSD and a BACT determination. The major source trigger levels as well as the significant emissions rates are pollutant specific and are shown in Table 5-1. Also shown in Table 5-1 are the potential emissions from the PEP facility.

Prevention to Significant Deterioration (PSD) requirements, including BACT, are applicable to greenhouse gas (GHG) emissions as indicated in 40 Code of Federal Regulations (CFR) 52.21(b)(49)(iv). There is no delegation agreement in place between the US Environmental Protection Agency (EPA) and the Antelope Valley Air Quality Management District (AQMD) under which the AQMD implements the PSD requirements, therefore PSD review is under the jurisdiction of EPA Region 9. CO_2e emissions are also included in Table 5-1.

Table 5-1
PSD Major Source and Significant Emissions Levels and Estimated Project Emissions

Pollutant	Major Source Trigger, TPY	Significant Emissions, TPY	Project Emissions, TPY[1]
NO_x	100	40	138.99
CO	100	100	351.09
VOC	100	40	51.64
TSP,PM10/2.5	100	15/10	81.01
H_2SO_4	100	7	4.8
CO_2e	-	75,000	2,117,775

Notes:
[1] Project emissions are the worst case for each pollutant based on the three proposed operational scenarios. These emissions estimates include the turbines/duct burners, aux boiler, and IC engines.
[2] SO_2 emissions are not subject to PSD BACT review for this facility.
As stated earlier in Section 4, the term PM10/2.5 will include TSP by default.

The source is "major" for NO_x, CO, VOCs,, PM10, PM2.5 and CO_2e. The source is minor for SO_2 and H_2SO_4. Based on the above, a BACT analysis for the following pollutants must be performed: NO_x, CO, VOC, PM10, PM2.5, and CO_2e. The required BACT analyses for the turbines/duct burners, auxiliary boiler, emergency fire pump and emergency generator, dry cooling tower, and circuit breakers are presented below.

5.2 BACT ANALYSIS METHODOLOGY

The BACT analyses conducted addresses the EPA BACT definition and has been prepared following the steps of the EPA's top-down BACT analysis method.

5.3 TOP-DOWN BACT ANALYSIS METHODOLOGY SUMMARY

On December 1, 1987, the EPA Assistant Administrator for Air and Radiation issued a memo that implemented certain program initiatives to improve the New Source Review (NSR) program, one of which was the "top-down" method for determining BACT. The steps for conducting a top-down BACT analysis are listed in EPA's *New Source Review Workshop Manual*, Draft (EPA 1990). Each step of the top-down method of determining BACT is described briefly below.

Step 1: Identify All Control Technologies

The first step in the top-down method is to list all available control technologies that may apply to the emission unit and the regulated pollutant being evaluated. The list of control alternatives should include existing technologies and innovative control technologies. Technologies required by lowest achievable emission rate (LAER) determinations must also be included. According to EPA's *New Source Review Workshop Manual*, "an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."

Step 2: Eliminate Technically Infeasible Options

The second step in the top-down method is to eliminate any of the identified control technologies that are technically infeasible with respect to the emission unit being evaluated. A determination of technical infeasibility is based on physical, chemical, and engineering principles. Technical difficulties that would preclude successful application of the control technology to the emission unit under review are also considered. All technologies that are identified as being technically infeasible are then removed from further review in the BACT analysis.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

In the third step of the top-down method, all remaining control technologies that were not eliminated as being technically infeasible are ranked and listed in order of control effectiveness for the pollutant under review, with the most effective control at the top of the list. In some instances Step 3 and Step 4 which follows are not required due to data presented in Steps 1 and 2.

Step 4: Evaluate Most Effective Controls and Document Results

In the fourth step of the top-down method, an analysis is presented that details the associated environmental, energy, and cost impacts associated with the control technologies. An objective evaluation of each impact, including both beneficial and adverse impacts, should be included. If an applicant is proposing the top control technology, then detailed impact information is not necessary. If the top control technology is not chosen, then the associated energy, environmental, and economic impacts are considered. If, based on the impacts, the top technology is shown to be inappropriate, the analysis proceeds to the next most effective control in the listing. The process continues until the technology under consideration is not eliminated because of energy, environmental, or economic impacts.

Step 5: Select BACT

The most effective control option that is not eliminated in Step 4 is proposed as BACT for the pollutant and emission unit under review.

5.4 TURBINE AND DUCT BURNER NORMAL OPERATION BACT ANALYSES

The exhaust from the turbines will be combined with the exhaust from the duct burners. In a combined-cycle plant the duct burners cannot normally be fired without the turbine being on line. This is the case for the proposed PEP design. Add-on control devices that would control emissions from the turbines will also control emissions from the duct burners. As a result, for the add-on control methods reviewed, emissions from the duct burners and turbines are analyzed together.

5.4.1 Turbine And Duct Burner Normal (Base Load) Operation NO_X Analysis

The BACT analysis for NO_X emissions from the Siemens SGT6-5000 turbines and duct burners is presented below.

Step 1: Identify All Control Technologies

Potential NO_X control technology options for the turbines and duct burners are:

- Catalytic combustion (K-LEAN™);
- Lean Pre-Mix Combustion, also referred to as dry low NO_X combustion (DLN);
- Water or steam injection;
- Selective Non-Catalytic Reduction (SNCR);
- Selective Catalytic Reduction (SCR); and
- EMx.

Catalytic Combustion

Catalytic combustion is a NO_X pollution prevention option for combustion turbines that limits the temperature in the combustor preventing NO_X formation. The only commercially available catalytic combustion system for combustion turbines is K-LEAN™ (formerly Xonon™), available from Kawasaki. K-LEAN™ is only available on small turbines (<20 megawatts [MW]). The use of Xonon™ technology on a 750 MW combustion turbine project south of Bakersfield, California called the Pastoria Energy Facility was proposed but never undertaken. Instead, the project was ultimately constructed using DLN combustion turbines equipped with SCR.

Catalytic combustion technology has yet to be demonstrated on large combustion turbines and is therefore not an available technology for this project.

Lean-Premix Combustion

Lean-premix combustion, also referred to as DLN, is also a NO_X pollution prevention option for combustion turbines. DLN limits NO_X formation by limiting combustion temperature and equalizing temperature distribution. This is accomplished by thoroughly premixing fuel with air in a lean (containing more air than is stoichiometrically required) mixture prior to injection into the combustion chamber. Turbines available for purchase in the size-range of this project's turbines are usually equipped with a lean-premix combustion system.

SCR

SCR is a post-combustion NO_X control method in which ammonia is injected into the exhaust stream in a catalytic reactor. SCR is widely used on combined-cycle combustion turbines and is an available technology for NO_X control for the turbines and duct burners.

EMx

EMx (formerly $SCONO_X$) is a post-combustion catalytic oxidation and absorption NO_X control system offered by EmeraChem. This technology uses parallel catalyst beds to reduce NO_X and CO emissions simultaneously. The EMx system includes a second catalyst bed knows as ES_X™. ES_X™ is needed to capture sulfur compounds in the exhaust stream. The EMx bed preferentially absorbs sulfur compounds masking the catalyst. Sulfur compounds have been a problem for the EMx catalyst even for turbines fired exclusively on natural gas.

The EMx catalyst beds become saturated with NO_X and have to be regenerated as frequently as every 20 minutes. Regeneration takes from 5-7 minutes. The beds are taken off line using mechanical dampers and a dilute concentration of hydrogen in steam is used to regenerate the off-line bed. The regeneration gas, containing molecular hydrogen and carbon dioxide (CO_2) in steam, is produced from natural gas.

The EMx catalyst upstream of EMx catalyst is regenerated at the same time. The ES_X™ catalyst oxidizes sulfur dioxide (SO_2) to sulfur trioxide (SO_3). During regeneration, the SO_2 is released and exhausted with the regeneration gas.

EMx has been demonstrated on several small turbines. The largest is a 45 MW turbine at the Redding, California municipal power plant. EMx has not been demonstrated on a large turbine or on a turbine configuration that includes duct firing. The La Paloma Generating Project in California initially proposed to demonstrate EMx on 150 MW turbines, but ultimately an SCR system was installed instead. This was also the case with the Otay Mesa project also located in California. Over 10 years ago, Goal Line Environmental Technologies LLC, the inventor of $SCONO_X$, entered into an agreement with Alstom Power Company making Alstom the EMx supplier for turbines larger than 100 MW. That agreement never resulted in the use of EMx on a turbine larger than 100 MW.

There are many questions surrounding the scale up and reliability of the EMx technology. Turbine size has an impact on the physical and chemical characteristics of the exhaust stream. Although the exhaust streams from turbines of different sizes may contain the same pollutants, the pollutant concentrations will be different. In addition, the exhaust temperatures and flow rates will also differ. The addition of duct burner exhaust further differentiates the exhaust streams from this project's turbines and duct burners from the exhaust streams upon which EMx has been demonstrated.

A primary concern related to use of EMx on large turbines is the distribution of both exhaust gas and regeneration gas across the catalyst. To achieve low NO_X emission levels, proper distribution across the catalyst is critical. In fact, the first generation of the $SCONO_X$ system had to be taken out of operation because of problems with regeneration gas distribution.

The larger heat recovery steam generator (HRSG) associated with a turbine larger than the turbines using EMx presents a significant challenge in achieving proper regeneration gas distribution and is a hurdle in system scale up. A model of fluid flow dynamics and distribution generated by Alstom Power indicated that the EMx regeneration gas delivery method used on the smaller turbines required redesign to achieve appropriate gas distribution on a large turbine (Czarnecki 2001, *Performance of SCONOx™ Emission Control Systems*). Several mechanical distribution systems were considered to help achieve uniform gas distribution. A design was chosen and flow scale modeling was performed to verify the effectiveness of the design (Czarnecki 2001). While the research results helped select a design, the newly designed manifold system has not been tested on a large gas turbine.

In addition to regeneration gas distribution, there is also a scale up concern associated with the many mechanical linkages, activators, and damper seals that must operate reliably for the system to remain online and provide successful emission control. Alstom also researched damper system scale-up. Four full-scale damper assemblies were tested at operation temperature for 100,000 cycles (equivalent to about three years of operation in the field). This testing revealed several problems. Alstom believed they had solved the identified problems (Czarnecki 2001). These solutions have not been tested on a large turbine in commercial operation.

While research and development has been performed to design a EMx system that can be used successfully on large-scale turbines, questions associated with the reliability and long-term performance of a large-scale EMx system remain. Until EMx is operated commercially on a large-scale turbine and on a turbine configuration including duct firing, it cannot be considered a viable control option for large turbines and turbines systems with duct firing.

Even with the many concerns surrounding the scale up and reliability of the EMx system, it has been considered an available technology for large turbines by some regulatory agencies.

The applicant believes that the EMx™ technology should not be considered as a viable control technology due to a complete lack of progress or showing, over the last 10-15 years, that the technology is scalable to turbines in excess of approximately 50 MW. For this reason the EMx™ technology is being eliminated from consideration.

Step 2: Eliminate Technically Infeasible Options

Two of the control options are technically infeasible for the PEP turbines and duct burners.

Water or Steam Injection

Water or steam injection has been widely used for NO_X emission control. Water or steam is injected into the combustion chamber and acts as a heat sink, reducing the formation of thermal NO_X. This control method works well on diffusion flame turbines, but injection of steam or water into the combustion zone does not enhance NO_X emission reductions on DLN turbines. As a result, water or steam injection is not considered a technically feasible NO_X reduction method for this project.

SNCR

SNCR is a post-combustion control method in which ammonia or urea is injected into the exhaust stream, reducing NO_X to nitrogen and water. SNCR works in a temperature range of 1,600 to 2,200 degrees Fahrenheit (^{o}F) and requires a residence time of 100 milliseconds (EPA 1993, *Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines*, *EPA-453/R-93-007*). The temperature range required for SNCR is higher than the exhaust temperature from combined-cycle combustion turbines and the flow velocities necessary to meet the residence time are much slower than the flow velocities for combined-cycle combustion turbines. SNCR is therefore not considered a technically feasible NO_X reduction method for this project.

Remaining Technologies

The remaining control technologies that are technically feasible and available are DLN and SCR. These two technologies are analyzed further below.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Turbines available for purchase in the size-range of this project's turbines are equipped with DLN. DLN is built into the turbines and is integral to turbine operation. Use of DLN is a form of pollution prevention. In EPA's *New Source Review Workshop Manual* (EPA 1990), as part of a discussion on calculating baseline emissions for determining cost effectiveness, the application of post- process emission controls to "inherently lower polluting processes" is addressed. This discussion indicates that for inherently lower polluting processes, baseline emissions may be assumed to be the emissions from the lower polluting process itself. A turbine equipped with DLN is an "inherently lower polluting process." As such, post-combustion control technologies will be evaluated in conjunction with DLN.

Emission rates for each of the technically feasible technologies are required to rank the technologies in order of effectiveness. Siemens guarantees an exhaust NO_X concentration of 9 parts per million by volume (ppmv) at 15% oxygen (O_2) from the SGT6-5000 turbines. The PEP turbines equipped with SCR will comply with a NO_X

emission limit of 2 ppmv at 15% O_2 on a 1-hour average basis. The control technology ranking using these emission concentrations is shown in Table 5-2.

Table 5-2
NOx Control Technology Rankings

Technology and Rank	Emissions Level Achieved, ppm
SCR and DLN – Rank 1	<= 2 ppm
DLN – Rank 2	9-12 ppm
Notes: PPM levels are for normal operations with duct firing mode On.	

Step 4: Evaluate Most Effective Controls and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The top-down process requires that the evaluation begin with the most effective technology. For this project, the most effective and proven technology are SCR with DLN.

SCR and DLN

There are energy and environmental impacts associated with the use of SCR to control emissions from DLN turbines. The energy impacts result from the increased backpressure the control system places on the turbine. The increased backpressure increases the heat input required to produce power and reduces the peak power output of the turbine. A pressure drop of ~3 inches is expected for SCR.

A document looking at the use of CO oxidation catalysts to control hazardous air pollutant (HAP) emissions from gas turbines includes an estimate of the energy penalties associated with increased backpressure. This document, (ICCR 1998a, *Cost-Effectiveness of Oxidation Catalyst, Control of Hazardous Air Pollutant (HAP) Emissions from Stationary Combustion Turbines)*, includes an estimate of the increased heat rate input required to compensate for the pressure drop associated with the catalyst. The Work Group used a heat rate increase of 0.105% per inch of pressure drop measured in inches of water. The document goes on to say that this is a low estimate and that most turbines would experience a higher increased heat rate requirement. For heavy- frame turbines, the document cites a rule of thumb estimate of 0.15% penalty per inch of pressure drop.

The document also discusses the loss of power production capacity when the turbine operates at full load that results from the increased exhaust backpressure. This power loss is 0.15% per inch of pressure drop. This reduced capacity is also an energy impact.

Based on the additional 3 inches of pressure drop associated with the SCR system, the energy penalty for the system would be 0.45% heat input penalty and a 0.45% peak power penalty.

SCR technology has two well-documented potential environmental impacts, ammonia emissions and handling and disposal of spent catalyst. Some ammonia emissions from an SCR system are unavoidable because of imperfect distribution of the reacting gases and ammonia injection control limitations. This ammonia slip is either directly emitted or reacts with the sulfur and nitrogen in the exhaust stream to form ammonia salts. The ammonia salts are emitted as PM. Dispersion modeling for the PEP project has shown that the impacts of PM_{10} and $PM_{2.5}$ emissions will be below the National Ambient Air Quality Standard (NAAQS) limitations.

The safety aspects of handling ammonia were addressed by (EPA 2000, *NO_X Control on Combined Cycle Turbines)*. This document indicates that although ammonia is identified by EPA as an extremely hazardous substance, it is typically handled safely and without incident. This is especially true of the aqueous ammonia (industrial grade) that will be used at the PEP facility. The use of aqueous ammonia rather than anhydrous ammonia greatly reduces the risks associated with ammonia use. Use of aqueous ammonia greatly reduces the probability and severity of accidental releases. Spills associated with aqueous ammonia can also be more easily contained and cleaned up. By using aqueous ammonia, the safety issues associated with anhydrous ammonia storage and handling will be minimized.

The other potential environmental impact associated with SCR is disposal of the catalyst. Modern catalysts used in SCR systems are showing useful lifetimes of well over 6 years. These catalysts contain heavy metals including vanadium pentoxide. Vanadium pentoxide is an acute hazardous waste under the Resource Conservation and Recovery Act (RCRA), Part 261, Subpart D – Lists of Hazardous Materials. This must be addressed when disposing of the spent catalyst. This potential impact is mitigated through recycling, i.e., the spent catalyst is returned to the catalyst manufacturers for reactivation or recycling.

Costs

SCR in combination with DLN is a proven control technology. There are literally hundreds of projects across the country that have proposed and installed SCR systems in various sizes and configurations. The applicant is not aware of any data for a combined cycle facility such as PEP that would indicate that SCR with DLN is not cost effective. Early data compiled by EPA (*EPA-452/F-03-032, CICI Fact Sheet*) indicated that SCR on large frame turbines would result in cost effectiveness values in the range of $3000-6000 per ton of NOx removed. Cost values for newer turbines are still in this range but can be higher since the uncontrolled floor is now DLN at 9 ppm instead of older values in the range of 25-42 ppm (for natural gas). Using a 9 ppm floor results in cost values that actually represent “incremental costs”, rather than a base cost effectiveness value. The applicant has estimated the control cost effectiveness (on a per turbine basis) for NOx using the standard EPA cost analysis procedures. These results are presented in Appendix D. The cost effectiveness of the proposed SCR system, assuming the reduction is from 9 to 2 ppm is $4,900/ton of NOx removed. This value is reasonable and well within the cost range of other similar facilities.

Step 5: Select BACT

The final step in the top-down BACT analysis process is to select BACT.

The PEP project will use SCR and DLN. The use of SCR and DLN in combination is both proven and achieved in practice. Table 5-3 presents the anticipated energy, environmental, and cost impacts of using the SCR/DLN system.

Table 5-3
NOx Control Technology Impacts

Technology	Energy Impacts	Environmental Impacts	Cost Impacts
SCR and DLN	Increased pressure drop Potential heat input penalty Potential power penalty	Ammonia emissions PM emissions increase Ammonia handling/storage Catalyst disposal/recycling	~$4900/ton removed
Notes: All data for a single turbine/DB unit.			

The BACT emission limit of 2.0 ppmv at 15% O_2 on a 1-hour average proposed for the PEP project has been compared to other emission limits imposed on similar projects. EPA's Reasonably Available Control Technology (RACT)/BACT/LAER Clearinghouse (RBLC), a database of past technology decisions, a listing of turbine projects maintained by EPA, and information on projects permitted in California and other states have been reviewed to compile a listing of turbine NO_x emission limits.

The Applicant could only identify one project with duct firing and an emission limit less than 2 ppmv at 15% O_2 on a 1-hour average was identified. The IDC Bellingham project was issued an emission limit of 1.5 ppmv. This project was cancelled and never constructed. As a result, compliance with this limit has not been demonstrated. The lowest demonstrated emission limit is therefore the limit proposed for this project for normal operations, 2.0 ppmv at 15% O_2 on a 1-hour average.

A BACT limit must not be higher than an emission limit in an applicable New Source Performance Standard (NSPS). The NO_x emission limit from 40 CFR 60, Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines," will apply. The NO_x limit in this subpart is 15 ppmvd at 15% O_2. The applicable NSPS limit is much higher than the 2.0 ppmv at 15% O_2 limit proposed as BACT.

Note that the emission limit proposed in this section as BACT for normal operations cannot be achieved during startup, shutdown, or tuning. As BACT must be applied at all times and the proposed normal operation emission limit is not achievable during other operating modes, a separate BACT analysis is required for startup and shutdown. That analysis is provided in Section 5.4.4 of this document.

5.4.2 Turbine and Duct Burner Normal (Base Load) Operation CO and VOC Analysis

The BACT analysis for CO and VOC emissions from the PEP turbines and duct burners is presented below.

Step 1: Identify All Control Technologies

Four control technologies have been identified for CO and VOC control. They are:

- Catalytic combustion (K-LEAN™);
- Oxidation catalyst; and
- Combustion controls.

Both the EMx and K-LEAN™ technologies were described in detail in Section 5.4.1. The CO catalyst is a post-combustion control device applied to the combustion system exhaust, while combustion controls are part of the combustion system design.

As discussed in Section 5.4.1.1, the only commercially available catalytic combustion system for combustion turbines is K-LEAN™ (formerly Xonon™). K-LEAN™ is only available on small turbines (<20 MW). A 750 MW project south of Bakersfield, California was to be used to demonstrate the Xonon™ technology on larger turbines. The project was ultimately constructed using DLN combustion turbines equipped with oxidation catalysts. As a result, catalytic combustion has yet to be demonstrated on large combustion turbines and is not available for this project.

EMx (formerly $SCONO_X$) was discussed in detail in Section 5.4.1 and eliminated as a viable control technology due to the lack of progress in showing or proving that the technology can be scaled up to turbines larger than 50 MW.

Step 2: Eliminate Technically Infeasible Options

Oxidation catalysts and combustion controls are technically feasible for this project.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

To rank the control technologies, it is necessary to estimate the level of control each technology offers. The Siemens turbines/duct burners to be used for the PEP project typically have a maximum uncontrolled exhaust CO concentration of less than 15 ppm. The PEP turbines equipped with oxidation catalysts will achieve a CO exhaust concentration of 2.0 ppmv at 15% O_2 on a 1-hour average, and a VOC concentration of 1 ppm at 15% O_2 on a 1-hour average (with duct burners operational, the VOC concentration will be 2.0 ppm). The control technology ranking for the CO and VOC BACT analysis is shown in Table 5-4.

Table 5-4
CO and VOC Control Technology Rankings

Technology and Rank	**CO Emission Level Achieved, ppm**
Oxidation catalyst (with and without duct burners)	2 ppm
Good combustion practices (no add-on control)	<= 9 ppm
Technology and Rank	**VOC Emission Level Achieved, ppm**
Oxidation catalyst without duct burners	1 ppm
Oxidation catalyst with duct burners operational	2 ppm
Good combustion practices (no add-on control)	3 ppm
Notes: PPM levels are for normal operations with and without duct firing mode.	

Step 4: Evaluate Most Effective Controls and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The top-down process requires that the evaluation begin with the most effective technology. The top technology is an oxidation catalyst.

There are environmental and energy impacts associated with the use of oxidation catalysts. As with other add-on control devices, there are energy impacts associated with oxidation catalysts. The increased backpressure in the turbine that results from adding the catalyst increases the heat input required and reduces the peak power output of the turbine. A typical increase in backpressure from the oxidation catalyst panels for a frame-size turbine is approximately 1 inch (ICCR 1998a). Using the rule of thumb energy penalties of 0.15% per inch heat rate penalty and 0.15% per inch peak power penalty discussed in Section 5.4.1, this results in a heat input penalty of 0.15% and a peak power penalty of 0.15%.

Disposal of the spent catalysts could represent an environmental impact. The catalysts used must be replaced periodically, usually about every 6 years. The catalyst contains heavy metals that may cause the spent catalyst to be considered a hazardous waste. However, catalyst vendors typically accept return of spent catalysts for recovery and reuse of the catalysts' precious metals and the environmental impact is mitigated.

Costs

Use of a CO oxidation catalyst is a proven control technology. There are literally hundreds of projects across the country that have proposed and installed CO catalyst systems in various sizes and configurations. The applicant is not aware of any data for a combined cycle facility such as PEP that would indicate that a CO catalyst system is not cost effective. Cost values for newer turbines can be higher as compared to older turbines which were constructed with older versions of CO catalysts, since the uncontrolled floor is now at 9 ppm instead of older values in the range of 12-15 ppm (for natural gas). Using a 9 ppm floor results in cost values that actually represent "incremental costs", rather than a base cost effectiveness value. The applicant has estimated the control cost effectiveness (on a per turbine basis) for CO using the standard EPA cost analysis procedures. These results are presented in Appendix D. The cost effectiveness for CO of the proposed CO catalyst system, assuming the reduction is from 9 to 2 ppm is $3,400/ton of CO removed. This value is reasonable and well within the cost range of other similar facilities.

Step 5: Select BACT

The final step in the top-down BACT analysis process is to select BACT.

The CO BACT emission limit of 2.0 ppmvd at 15% O_2 on a 1-hour average proposed for the PEP project has been compared to other emission limits imposed on similar projects. EPA's RBLC, EPA's turbine spreadsheet, information on projects permitted in California, and information available from other air quality regulatory agencies have been reviewed to confirm the applicability of the proposed turbine CO emission limits. The majority of BACT emission limits issued for frame-size combustion turbines is 2 ppmv at 15% O_2 on a 1-hour average. Emission limits for six (6) projects identified with emission limits less than 2 ppmv at 15% O_2 are shown in Table 5-5.

Table 5-5
Facilities with CO BACT Limits Less than 2 PPM

Facility Name	CO Emissions Limit, ppm	Comments
Kleen Energy Systems	0.9 w/o DB 1.7 w/DB	Online May 2011
Avenal Power Center	1.5 w/o DB 2.0 w/DB	Not built
VEPC-Brunswick Plant	1.5 w/o DB 2.4 w/DB	-
VEPC-Warren County Plant	1.5 w/o DB 2.4 w/DB	-

Palmdale Hybrid Plant	1.5 w/o DB 2.0 w/DB	Not built
SCGP-McDonough Plant	1.8	3-hr averaging period
Notes: ppm values at 15% O2 (Dry)		

As indicated in Table 5-5, the limits below 2 ppmvd at 15% O_2 for several of these facilities are for operation without duct firing. The CO limits for Avenal Power Center LLC and Palmdale Hybrid Power Project with duct firing are 2.0 ppmvd at 15% O_2. The limits without duct firing for these projects do not have to be met for the first three years of operation. The CO limits for the Virginia Electric and Power Company, Warren County Facility, and Brunswick Plant with duct firing are 2.4 ppmvd at 15% O_2.

The CO emission limit for the Southern Company/Georgia Power, Plant McDonough project is1.8 ppmv at 15% O_2 on a 3-hour average. With the longer averaging period, this limit is not appreciably more stringent than the 2 ppmv limit on a 1-hour average proposed for the PEP project.

In 2002, Kleen Energy Systems, LLC (Kleen Energy) submitted a permit application to the Connecticut Department of Environmental Protection, Bureau of Air Management for a combined-cycle combustion turbine project to be located in Middletown, Connecticut. The project consists of two dual fuel Siemens SGT6-5000F combustion turbines, a heat recovery steam generator, and 445 million British thermal units per hour (MMBtu/hr) duct burners. In its permit application, Kleen Energy proposed a BACT limit of 1.8 ppmv at 15% O_2 for natural gas combustion. The BACT analysis included no discussion of energy or economic impacts associated with the use of oxidation catalysts and the only environmental impact mentioned was the tendency of SO_2 to oxidize to SO_3 with the use of fuel oil. In 2006, Kleen Energy submitted updated BACT analyses for the project. The CO BACT analysis was unchanged.

In 2007, the Connecticut Department of Environmental Protection (Connecticut DEP), Bureau of Air Management prepared an engineering evaluation for the Kleen Energy project and selected CO BACT levels for natural gas combustion of 0.9 ppmvd at 15% O_2 without duct firing and 1.7 ppmvd at 15% O_2 with duct firing. The engineering analysis did not include any discussion of environmental, energy, or economic impacts associated with CO control. A New Source Review (NSR) permit was issued for the project on February 25, 2008 (CDEP 2007, *NSR Engineering Evaluation, Firm Name: Kleen Energy Systems, LLC*) and contained the emission limits included in the state's engineering evaluation (CDEP 2008, *New Source Review Permit to Construct and Operate a Stationary Source, Owner/Operator: Kleen Energy Systems LLC*.).

Following issuance of the Kleen Energy permit, at least 30 permits were issued for natural gas- fired, combined-cycle turbine projects with CO BACT limits of 2 ppmvd at 15% O_2 or higher. In several cases the permitting authority considered the Kleen Energy permit limits as outliers. In others, because the facility had yet to be constructed or had only been operating for a short time, the lower limits were determined not to have been demonstrated in practice.

The Kleen Energy project turbines started up in early May 2011. Following startup of the project, EPA Region 9 issued permits for the Avenal Power Center LLC and Palmdale Hybrid Power Projects with BACT limits of 1.5 ppmv at 15% O_2, but the permits do not require compliance with the lower limits for three years. The delay in compliance with the lower limits was because of the lack of long-term compliance data demonstrating achievement of the lower limits (EPA 2011a, *Reponses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Avenal Energy Project,* and EPA 2011b, *Reponses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Hybrid power Project*). The oxidation catalysts used to control CO have a useful life of three to five years. Control is highest when the catalyst is new. As the catalyst ages, control becomes less efficient. To be demonstrated in practice, an emission limit below 2 ppmv at 15% O_2 would need to be met for at least three years. In addition, the Avenal plant has not yet been constructed.

To achieve an emission limit less than 2 ppmv at 15% O_2 requires the installation of more catalyst than that needed to meet a limit of 2 ppmv at 15% O_2. EPA Region 9 did not review the additional energy and economic costs associated with the use of additional catalyst. As discussed previously, oxidation catalysts increase the backpressure on the turbine increasing the heat input required to produce power and reducing the peak power output of the turbine. The increase in required heat input increases as catalyst is added and the decrease in peak power output of the turbine decreases with increased catalyst. The additional catalyst material also increases the cost of the control system, the cost of periodic catalyst replacement, the cost of fuel, and decreased revenue from decreased peak power output.

In 2009, Connecticut DEP, the same agency that permitted the Kleen Energy project with emission limits less than 2 ppmvd, agreed to a BACT recertification for Towantic Energy, LLC with a turbine CO limit of 2.0 ppmvd for natural gas combustion. Towantic Energy, LLC had received a permit in 2004 for a project with two combined-cycle GE Frame 7FA combustion turbines without duct firing. The original permit contained a CO BACT limit of 5.0 ppmv at 15% O_2. As the project was not constructed within three years of permit issuance, BACT recertification was required. The BACT recertification submitted for the project contained a CO BACT level of 2 ppmv at 15% O_2. The recertification application included energy and cost impact information for meeting either a 1.3 ppmv at 15% O_2 limit or a 0.9 ppmv at 15% O_2 limit (Towantic 2008). An incremental cost effectiveness of more than $7,000 per ton for a limit of 1.3 ppmv at 15% O_2 and a reduction in net power output capacity of 18 kilowatts (kW) were estimated and an incremental cost-effectiveness of $27,000 and a reduction of net power output capacity of 50 kW were estimated for a limit of 0.9 ppmv at 15% O_2. Based on the information provided, Connecticut DEP agreed to the proposed CO BACT limit of 2 ppmv at 15% O_2 (CDEP 2009, *Letter from Gary S. Rose, Director, Engineering and Enforcement Section, Connecticut Department of Environmental Protection, Bureau of Air Management to Mr. James Shapiro, Senior Vice President, Towantic Energy, LLC. RE: Recertification of Towantic Energy, LLC*).

In 2010, the Virginia Department of Environmental Quality (VDEQ) considered oxidation catalyst cost information for reducing the BACT limit with duct firing below 2.4 ppmv at 15% O_2 submitted for the Virginia Electric and Power Company, Warren County Facility. Virginia determined that it was not cost effective to require a lower CO limit (VDEQ 2010, *Engineering Evaluation of Prevention of Significant Deterioration (PSD) Permit Application Submitted by Dominion for Warren County Power Station Registration No, 81391*).

In 2013, the Bay Area Air Quality Management District (BAAQMD) re-issued a non-PSD permit for the Oakley Generating Station Project, a natural gas-fired, combined-cycle combustion turbine project proposing to use GE Frame 7FA, Model 5 turbines. Although the permit was not a PSD permit, BAAQMD regulations require a BACT analysis. BAAQMD reviewed the economic impacts associated with a CO limit of less than 2 ppmv at 15% O_2 and noted the associated energy impacts. BAAQMD determined that a limit below 2 ppmv at 15% O_2 was not cost effective (BAAQMD 2013, *Evaluation for Renewal of the Authority to Construct the Oakley Generating Station, Plant Number 19771*).

Each agency that has considered energy and cost impacts associated with a CO BACT limit below 2.0 ppmvd for natural gas combustion in combined cycle turbine system has determined that such a limit is not warranted. As a result, a CO BACT limit of 2.0 ppmvd at 15% O_2 is proposed as BACT for the PEP turbines.

A BACT limit must not be higher than an applicable NSPS emission limit. The requirements of 40 CFR 60, Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines," will apply to the turbines; however, the subpart does not include an applicable CO limit.

Note that the proposed CO BACT limit is for normal operations only and cannot be achieved during startup, shutdown, or tuning. As BACT must be applied at all times and the normal operation emission limit is not achievable during other operating modes, a separate BACT analysis is required for startup, shutdown, and tuning. That analysis is provided in Section 5.4.4 of this document.

5.4.3 VOC BAC for Turbine and Duct Burner Normal (Base Load) Operations

The data presented above for CO is directly applicable to emissions of VOCs from turbine/duct burner combinations. Uncontrolled emissions of VOCs for turbine/duct burner units from large frame turbines is typically on the order of 3 ppm. Use of an oxidation catalyst results in substantial reductions of VOCs in conjunction with reductions in CO emissions. The PEP proposed oxidation catalyst for CO control will also be the BACT choice for VOC. The oxidation catalyst will reduce VOC emissions from the turbine/duct burner exhaust to levels equal to or less than 2 ppm. Recent test data on large turbines has shown that short term VOC concentrations can be controlled to less than 2 ppm. But these short term values show increases over time as the catalyst efficiency degrades. As such, the VOC BACT limit chosen for the PEP turbine/duct burners is 2 ppm, based on a 1-hr average for duct firing mode, and 1 ppm for non-duct firing mode.

The cost effectiveness for VOC of the proposed CO catalyst system, assuming the reduction is from 3 ppm to 2 ppm is $54,941/ton of VOC removed. This cost would normally be considered excessive, but the control of VOCs is simply an added benefit from the CO catalyst that is separately demonstrated as BACT for CO.

5.4.4 Turbine and Duct Burner Normal (Base Load) Operation $PM_{10}/PM_{2.5}$ Analysis

For the turbines and duct burners it has been assumed that all of the particulate matter emissions will be $PM_{2.5}$. A single analysis will therefore be conducted for PM, PM_{10}, and $PM_{2.5}$. According to research conducted by GE (GE 2009, *Particulate Matter, PM10 and PM2.5: What is it, How is it Regulated, How is it Measured, and What is GE's Position on PM Emissions from Gas Turbines?*, *Revision 2*), particulate matter emissions from natural gas-fired turbines are from ambient PM that passes through the turbine inlet air filters, inert solids in the fuel gas supply, construction debris, and metallic rust or oxidation products.

Step 1: Identify All Control Technologies

Five control methods for the combustion devices have been identified for $PM/PM_{10}/PM_{2.5}$ control:

- Electrostatic precipitators (ESPs);
- Scrubbers;
- Fabric filters;
- Combustion of natural gas.

EmeraChem, the supplier of EMx, a post-combustion catalytic oxidation and absorption system discussed in Sections 5.4.1 and 5.4.2 of this application (not listed above), has been marketing the control system as an option for PM control as well as NO_X and CO control. No regulatory agency has yet verified that the control system is a viable option for PM control and no agency has yet considered it a technically feasible PM control technology in a BACT analysis. EMx has only been used on small turbines for NO_X and CO control and has never been demonstrated on large frame-size turbines like those to be used at PEP. Concerns about the technical issues associated with the scale-up of EMx were presented in detail Section 5.4.1. Given that EMx has not been proven as a viable PM control technology and that it has not been demonstrated on large turbines, EMx is not considered an available PM control option for the PEP project.

Step 2: Eliminate Technically Infeasible Options

ESPs, scrubbers, and fabric filters are not considered to be technically feasible options for gas turbines because of the high exhaust flow rates and low particulate matter loading associated with turbine exhaust. In addition to the flow rate and loading problems, the particle resistivity associated with gas turbine exhaust is a problem for ESPs. ESPs remove particles by charging the particles and then collecting them on plates. ESP performance is greatly affected by the ability of particles to accept and maintain a charge. Because of the resistivity of the exhaust particles from gas turbines, ESPs are not effective for turbine PM control. Corrected cost data presented in (AECOM 2010, *PHPP PSD Application Supplemental Information, Section 8, BACT*) and updated to reflect 2015, indicates that control cost effectiveness for PM control devices on combustion turbines for technologies such as ESPs and fabric filters ranges from $167,200 to $143,900 per ton removed. These values are well in excess of established cost effectiveness values for PM. Because of the technical infeasibility of these technologies, no further analysis was attempted.

Steps 3, 4 and 5: Select BACT

As a result of the top-down analysis, the only remaining control method is the use of natural gas; therefore, Steps 3 and 4 are unnecessary and the use of natural gas is chosen as the basis for BACT for this project. This decision is consistent with the decisions contained in the RBLC for particulate matter emissions associated with natural gas-fired combustion turbines. Information from the RBLC, EPA's turbine spreadsheet, and information on projects permitted in California show that add-on controls for PM have not been required for any natural gas-fired combustion turbine project.

A maximum (combined filterable and condensable) $PM/PM_{10}/PM_{2.5}$ limit of 11.8 pounds per hour (lb/hr) is proposed for each PEP turbine and duct burner pair. PM emission limits issued to other similar turbines have been reviewed to determine if this limit represents BACT for this project.

The proposed $PM/PM_{10}/PM_{2.5}$ limit of 11.8 lb/hr (combined filterable and condensable) for each PEP turbine and duct burner pair is comparable to other recently permitted projects and is proposed as BACT. Additionally, it must be remembered that the emissions of PM, in all size ranges, is dependent upon the firing scenario of the turbines/duct burners as well as ambient conditions. The estimated range of PM emissions (all size ranges) is from 8.0 to 11.8 lbs/hr, or less than or equal to 0.0048 lbs/mmbtu.

A BACT limit must not be higher than an applicable NSPS emission limit. The requirements of 40 CFR 60, Subpart KKKK, "Standards of Performance for Stationary Combustion Turbines," will apply to the turbines; however, the subpart does not include an applicable PM, PM_{10}, or $PM_{2.5}$ limit.

The proposed BACT limit can be met during all turbine operating conditions, including startup, shutdown, making a separate BACT analysis for those conditions unnecessary for PM, PM_{10}, and $PM_{2.5}$.

5.4.5 Turbine and Duct Burner Startup, Shutdown, and Tuning Analysis

The proposed NO_X, VOC, and CO BACT emission limits for normal operation of the turbines cannot be met during periods of startup, shutdown, and tuning. Turbine tuning occurs primarily after routine maintenance when the turbine is tested at various incremental loads, during which the emission controls may not be operating and emissions are often similar to those associated with cold startup.

Startup sequences for combined-cycle combustion turbines are specified by the equipment vendors and include multiple steps in which the equipment power output is gradually increased until normal operating conditions are reached. The combustion turbines' speed and load are carefully increased as the HRSG, steam drums, steam piping, emissions control equipment, steam turbine, and other equipment are heated and brought to a stable operating condition. The gradual increase is necessary to protect personnel and equipment and to maintain equipment warranties.

One of the primary reasons that normal operation emission limits cannot be met during startup, shutdown, and tuning is that the DLN system cannot be operated at low loads. To ensure proper function at normal operating loads, the injector nozzles connecting the premixing chamber to the combustion chamber must be large enough to ensure that the fuel-air mixture flows into the combustion chamber at the proper rate. During startup, shutdown, and tuning when the turbine is not at an operational load, the low fuel flow from the nozzles is insufficient to prevent the flame wall in the combustion chamber from backing up into the premixing chamber. To avoid the risk of fuel blowback, which could cause the premixing chamber to overheat, the premixing chamber must be bypassed when the unit is in startup, shutdown, or tuning mode. When the premixing chamber is bypassed, the turbine operates like a standard single-stage diffusion flame turbine.

In addition to the startup requirements of the turbine, the NO_X and CO (VOC) control equipment do not provide control, or provide only partial control, when the exhaust temperatures are not at optimum levels. Until the optimal exhaust temperature range for the controls is reached and the catalysts are at operating temperature, the control devices do not operate at design levels. As such, during the periods of startup, shutdown, and tuning, the DLN system is not operating to minimize emissions and the emission control systems are not capable of efficiently controlling the emissions that are generated.

As these conditions are part of the expected operation of the turbines, the requirement to meet BACT still applies. As the normal operation BACT emission limits cannot be met, a BACT analysis specifically for these conditions is required for the turbines for NO_X and CO (and VOC), taking into account the conditions that exist during startup and shutdown.

Generation of NO_X and CO emissions from combustion are interrelated. Higher combustion temperatures lead to more complete combustion and lower CO emissions, but produce higher NO_X emissions. Conversely, lower temperatures reduce the generation of NO_X, but the associated incomplete combustion yields higher CO emissions. Because emission control equipment performance is diminished during startup, shutdown, and turning, the generation of emissions during these operating conditions will influence the BACT analysis to a greater extent than during normal operations. As such, the BACT analyses for NO_X and CO (and VOC) have been combined for startup and shutdown.

Step 1: Identify All Control Technologies

The following control options have been identified as possible strategies for reducing emissions during startup and shutdown:

- Fast start design such as Siemens Flex Plant™;
- Work practices.

Total emissions during startup, shutdown, and tuning are a factor of the emissions generated and emitted and the length of the event. One of the primary reasons that combined-cycle turbines cannot start up faster is the need to slowly heat the thick-walled steam drum in the steam generator for safety and reliability purposes. Steam drum re-designs that eliminate the steam drum or use once-through steam technology, and designs using a steam drum with thinner walls have been developed to reduce startup times. In addition, fast start designs decouple the combustion turbine from the steam turbine during the early phases of startup, reducing low load, higher emission combustion turbine operation. These designs allow power plant operators to maximize energy production, but have the collateral benefit of reducing startup emissions by reducing startup times.

Siemens has developed a fast start combined-cycle turbine design using once-through steam technology. Conventional combined-cycle turbine facilities use a steam drum in the steam generator to contain the steam before it is introduced to the steam turbine. Once-through steam boiler technology replaces the steam drum with external steam separators and surge bottles so that startup can proceed more rapidly.

The Siemens once-through steam boiler design is called Fast Start and is used in integrated plant designs referred to as Flex Plant™ 10 and Flex Plant™ 30. The most recent version of Flex Plant design is simply refered to as Flex Plant

The only project operating with a Flex Plant™ 30 design is the Northern California Power Agency's Lodi Energy Center. The Lodi Energy Center has a one on one configuration (one combustion turbine and one steam turbine) and began operation in November 2012. Although the fast start technology is expected to reduce start times considerably, the permit issued by the San Joaquin Valley Air Pollution Control District (SJVAPCD; SJVAPCD 2010, *Final Draft Staff Report, Proposed Amendments to Rule 4306 (Boilers, Steam Generators, and Process Heaters – Phase 3), Proposed Amendment to Rule 4307 (Boilers, Steam Generators, and Process heaters – 2.0 MMBtu/hr to 5.0 MMBtu/hr), Proposed New Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and process Heaters Greater than 5.0 MMBtu/hr*) for the Lodi Energy Center contains an initial duration limit for startups and shutdowns of 3.0 hours and requires that within 15 months following commissioning the owner of the project, the Northern California Power Agency propose new startup durations based on data collected during the 12 month period following commissioning. As such, the Flex Plant™ 30 turbine is in a demonstration period for startup durations.

In January 2013, a request for a permit modification to raise the Lodi Energy Center turbine CO emission limit during startup was submitted (NCPA 2013, *Petition to Amend Air Quality Conditions of Certification for the Lodi Energy Center Project (08-AFC-10C*). The requested increase was necessary as under certain conditions, primarily cold ambient temperatures and after the turbine had been shut down for many hours, the startup CO emissions were higher than expected. The permit was modified in June 2013, raising the CO emission limit during startup from 900 lb/hr to 1500 lb/hr (SJVAPCD 2013, *Authority to Construct, Permit No. N-2697-5-1, Northern California Power, San Joaquin Valley Air Pollution Control District*).

Flex Plant™ 30 has been proposed for two additional projects in California, the Blythe Energy Project Phase II and the Huntington Beach Energy Project. Construction on the Blythe Energy Project Phase II project has not begun and permitting of the Huntington Beach Energy Project has not yet been completed.

Notwithstanding the above, the PEP facility (turbines/duct burners) is being designed to use the most recent design of the Flex Plant system. This design incorporates the use of an auxiliary boiler rated at 110 mmbtu/hr.

Step 5: Select BACT

As a result of the top-down analysis, the Flex Plant design in conjunction with the proposed auxiliary boiler is the chosen BACT option. In addition, the following "beyond BACT" work practices will also be used:

Work practices that will be used for startup are:

- Following plant equipment manufacturer and engineering design recommendations;
- Injecting ammonia as soon as possible; and
- Bringing the turbine load to the point that the normal operation

NO_X and CO emission limits can be met as quickly as possible, consistent with the equipment vendors' recommendations and safe operating practices.

During shutdown, the load would be reduced to zero as quickly as possible consistent with safe operating practices and equipment vendors' recommendations and ammonia injection to the SCR system would be maintained as long as the system remains above the minimum SCR operating temperature.

Even with a limited number of project emission values to review, emission limits for startup, shutdown, and tuning are extremely difficult to compare for a number of reasons. These include: the unique nature of startups for combined-cycle turbines, the definition of startup and shutdown, the delineation of types of startup, ambient conditions associated with the limits, and the form of the emission limits.

Startup is a function of integrated plant performance. Factors influencing startup include the turbine model, HRSG manufacturer and model, steam turbine manufacturer and model, plant distributed control system, configuration (arrangement and number of combustion and steam turbines), and other plant features. Vendors do not guarantee startup, shutdown, and tuning emissions. These emissions are based on vendor estimates and engineering calculations.

Ambient temperature and humidity influence turbine emissions including emissions during startup, shutdown, and tuning. It would seem that emission limits for these special operating conditions would be based on the worst-case ambient conditions; however, this may not be the case and would vary by location.

The form of startup and shutdown emission limits (mass per time, mass per event, average emission rate during event) varies considerably. Limits on the total mass emissions during an event are more comparable than limits expressed in other forms, with less uncertainty that different types of limits are being compared. Mass per event limits are available for the PEP for which the Flex Plant design is proposed.

Table 5-6 presents the startup/shutdown estimated emissions for the PEP. The limits proposed for the PEP turbines are within the range of the limits proposed for other projects that have selected a fast start design. The values listed in Table 5-6 are the proposed BACT limits for startups and shutdowns.

Table 5-6
Startup and Shutdown Emissions Per Turbine

Parameter/Mode	Cold Startup to 100% Turbine Load	Warm Startup to 100% Turbine Load	Hot Start to 100% Turbine Load	Shutdown from 100% Turbine Load
NO_x, lbs/event	51.48	46.8	43.2	33.0
CO, lbs/event	415.80	378	304.8	75.9
VOC, lbs/event	30.36	27.6	27.6	19.8
PM10/2.5, lbs/event	8.32	7.56	6.48	4.07

Parameter/Mode	Cold Startup to 100% Turbine Load	Warm Startup to 100% Turbine Load	Hot Start to 100% Turbine Load	Shutdown from 100% Turbine Load
Event Time, minutes (hours)	39 (0.65)	35 (0.583)	30 (0.5)	25 (0.417)
Maximum Number of Events/Year (Operational Scenario)	5 (Operational Scenario 1, 2 and 3)	360 (Operational Scenario 2 and 3)	360 (Operational Scenario 2)	725 (Operational Scenario 2)
* Startup data is not guaranteed by the vendor. A 20% and 10% margin has been added to the startup and shutdown emissions, respectively. During the remaining minutes during the start hour, Case 1 (23°F) full load, non duct burner emissions are used. Cold start event data is based on 100% turbine load at the end of the start cycle. Duct burner operation would not be available during the first hour of any start.				

Startup is proposed to be defined as "setting in operation of a turbine to the point that the control equipment has reached operating temperature and normal operation emission limits can be met." Shutdown is proposed to be defined as "from the point at which the combustion turbine load falls below the point at which the normal operation emission limits can be met to a point where the fuel supply can be cut off from the turbine."

5.4.6 Turbine and Duct Burner GHG Analysis

The BACT analysis for GHG emissions from the turbines and duct burners is presented below.

Step 1: Identify All Control Technologies

EPA has issued a document titled *PSD and Title V Permitting Guidance for Greenhouse Gases* (EPA 2011c). References provided in the EPA guidance document were consulted to identify GHG emission technology options. Two areas of power plant GHG emission reduction measures were identified:

- Carbon capture and sequestration (CCS); and
- Energy-efficiency measures.

The EPA guidance document indicates that CCS should be listed in Step 1 of the BACT analysis for large CO_2-emitting facilities (EPA 2011c). CCS involves capturing the GHGs, transporting them to a suitable storage location, and storing them securely in geologic reservoirs. CCS is an attractive option as emissions could be reduced substantially without changing the energy supply infrastructure. CO_2 is already captured in the petroleum and petrochemical industries and several gas-fired and coal-fired electric generating stations capture a small slipstream of CO_2 for sale as a commodity. Underground storage of CO_2 has taken place as a byproduct of the injection of CO_2 into oil fields for enhanced oil recovery (EOR).

Efficient power generation minimizes GHG emissions by minimizing the amount of fuel combusted. Combined-cycle turbine facilities are the most efficient commercial technology for central station power generation (EPA 2008a, *Catalog of CHP Technologies*. *US Environmental Protection Agency, Climate Protection Partnership Division, Combined Heat and Power Partnership*). Combined-cycle turbine system efficiency is influenced by a number of factors including turbine design and configuration.

Step 2: Eliminate Technically Infeasible Options

In this step each option listed in Step 1 is reviewed to determine if it is feasible for the project under review. Options that are technically infeasible for the project are eliminated.

CCS

There are three primary components to CCS: capture, transport, and storage. The feasibility of each of these components for the PEP turbines and duct burners is examined below.

CCS-Capture

The first CCS step is GHG capture. The goal of GHG capture is to produce a concentrated stream of GHGs that can be transported to a sequestration site. Several technologies in various stages of development exist for GHG capture. They can be divided into three approaches: pre-combustion capture, oxyfuel, and post-combustion capture.

Pre-combustion capture uses a gasification plant to convert the fuel to hydrogen and CO_2. The CO_2 can then be separated from the hydrogen fuel prior to combustion. This option is primarily being considered for coal in integrated gasification combined-cycle plants.

Oxyfuel or oxy-combustion uses nearly pure oxygen in the combustion process rather than air. This produces an exhaust stream that is primarily water and CO_2. The high concentration of CO_2 in the flue gas can then be captured. According to the Intergovernmental Panel on Climate Change (IPCC), this technology is only in the demonstration phase (IPCC 2005, *IPCC Special Report on Carbon Dioxide Capture and Storage*). Current studies indicate that the timeframe for this technology to be available on a commercial scale is 2017-2020 (Clean Air Strategic Alliance 2009).

Post-combustion capture separates GHGs from the exhaust stream. There are several process technologies that can be used for CO_2 capture. While post-combustion capture options are further developed for large-scale use than the other capture options, the scale of these systems is still considerably smaller than what is needed for a power plant, and there are difficulties in applying CO_2 post-combustion capture to power plants. These result from:

- Low pressure and dilute GHG concentrations in the exhaust (only 3%-4% by volume in exhaust from gas-fired turbines) require a high volume of gas to be treated;

- Trace impurities, such as NO_X, reduces the effectiveness of CO_2 adsorbing processes; and,
- Compressing CO_2 from atmospheric pressure to pipeline pressure requires a large amount of energy.

(NETL 2013, Online at www.netl.doe.gov/technologies/carbon_seq), and (ITF 2010, *Report of the Interagency Task Force on Carbon Capture and Storage*).

Much of the research into addressing these issues is focused on capture of GHG emissions from coal-fired power plants. This is because coal combustion produces about twice as much CO_2 as natural gas combustion (EPA 2013c, Online at www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html).

CCS-Transport

The second CCS component is transport to the sequestration site. CO_2 has been transported in pipelines in the United States for nearly 40 years and there are 3,600 miles of existing CO_2 pipelines (ITF 2010). There are no existing CO_2 pipelines within 50 miles of the PEP facility.

CCS-Storage

The final CCS component is the storage of CO_2 in subsurface formations. Natural CO_2formations known to have contained CO_2 over geologic time indicate the feasibility of engineered storage (ITF 2010) and injection of CO_2 into geologic reservoirs for EOR has occurred for many years. The Department of Energy (DOE) created a network of seven Regional Carbon Sequestration Partnerships to help develop “the technology, infrastructure, and regulations to implement large-scale CO_2 sequestration in different regions and geologic formations within the Nation” (NETL 2013). California is part of the West Coast Regional Carbon Sequestration Partnership and the Southwest Carbon Partnership.

Work by the partnerships is being conducted in three phases. Phase I was the Characterization Phase during which the partnerships identified opportunities for carbon sequestration. In Phase II, the Validation Phase, multiple small scale field tests were conducted. The partnerships are now into Phase III, the Development Phase, which involves large-volume sequestration tests. DOE’s NETL expects the results to “provide the foundation for CCS technology commercialization throughout the United States, including providing input that can be used in demonstration projects” (NETL 2013). The Development Phase is scheduled to last at least 10 years.

CCS Feasibility Determination

CCS is not a feasible GHG control option for the PEP turbines and duct burners as there are issues with each of the three CCS components.

No pre-combustion, oxyfuel, or post-combustion technology is currently demonstrated to capture GHG emissions at the scale needed for a combined-cycle combustion turbine plant. In February 2010, the President established an ITF chaired by EPA and DOE. In August 2010, the ITF issued a report that assessed current capture technologies as "not ready for widespread implementation because they have not been demonstrated at the scale necessary to establish confidence for power plant application" (ITF 2010). In addition, in reviewing natural gas processing facilities that currently capture the largest volume of CO_2, the ITF states, "the degree to which experience with natural gas processing is transferrable to separation of power plant flue gas is unclear, given the significant differences in the chemical make-up of the two gas streams" (ITF 2010).

The EPA guidance document states that "if a control option has been demonstrated in practice on a range of exhaust gas streams with similar physical and chemical characteristics … it may be considered as potentially feasible for application to another process" (EPA 2011c). The ITF has identified that differences in chemical make-up between the gas streams upon which demonstrated CO_2 capture technology has been applied and power plant flue gas are an uncertainty in the technical transfer of the technology.

CO_2 transport is also problematic. While there are no technology barriers to CO_2 transport through pipelines, the pipeline infrastructure currently does not exist in the Mohave Desert air basin.

Figure 5-1 shows the current location of CO2 Sequestration sites in California (NETL 2010, *2010 Carbon Sequestration Atlas of the US and Canada, 3rd Ediiton*). No sequestration sites are within a reasonable distance of the proposed project site.

Figure 5-1
Potential CO_2 Sequestration Locations by Type in California

Capture technology has not yet been demonstrated, transport infrastructure is lacking, and a commercially available storage site is many years away. As a result, CCS is still in a developmental stage and not yet available for controlling power plant GHG emissions. This current state of CCS for GHG emissions from power plants is confirmed in a statement made by EPA in the Advanced Notice of Proposed Rulemaking for the GHG Tailoring Rule in the discussion of potential options for regulating GHGs under the Clean Air Act: "… where critical new control strategies, such as carbon capture and storage, are still in the early stages of development" (75 FR 44485). CCS technology is not an available option for control of GHG emissions from the PEP turbines and duct burners and is eliminated from this BACT analysis.

Energy Efficient Power Generation

Energy efficient power generation is an available option for the PEP turbines and duct burners.

Solar Hybrid

The previous project (PHPP) included solar thermal equipment that proposed to utilize arrays of parabolic collectors to heat a high-temperature working fluid. The hot working fluid would then be used to boil water to generate steam and the steam would be injected into the HRSG drums/piping systems. The combined-cycle equipment is integrated thermally with the solar equipment at the HRSG and both utilize the single gas turbine.

A solar hybrid project's economics are dependent on having the combined cycle plant operating at base load when the solar generated steam is available to supplement natural gas fuel, otherwise there is no way to generate power with the solar portion of the plant and the economic value of that energy is lost. This will not generally be the case with in a flexible capacity resource which will typically operate to meet the ramping and peak load requirements in the morning and late afternoon thus helping to integrate the ramp up and ramp down of solar generation.

After review, it was determined that a solar hybrid is not cost effective and consistent with the Project Objectives to be a flexible capacity resource.

Steps 3, 4 and 5: Select BACT

The only remaining control option for the turbines and duct burners is energy efficient power generation. Steps 3 and 4 of the top-down BACT method are not applicable and efficient generation is selected as the basis for GHG BACT for the PEP combustion turbines and duct burners.

To determine the appropriate BACT level associated with efficient generation, the efficiency of the PEP combined-cycle combustion turbine plant was compared to the efficiency of other similar facilities. To accurately compare combined-cycle combustion turbine plant efficiencies, the basis of the efficiency values must be the same. The most critical aspects of the basis for combined-cycle combustion turbine plant efficiency include:

- Fuel Basis: The fuel basis for the efficiency can be on a lower heating value (LHV) basis or a higher heating value (HHV) basis. Typically, combustion turbine efficiency has been discussed on an LHV basis. The EPA guidance document indicates a preference for the use of HHV.
- Ambient Conditions: Combustion turbine efficiency varies with ambient conditions. Combustion turbine power production is a function of mass flow of air and exhaust gases through the turbine. As such, the lower the air density, the lower the power production and efficiency. Combustion turbine efficiency decreases as the ambient temperature increases, decreases as relative humidity decreases, and decreases as ambient pressure decreases.
- Power Production Basis: Combined-cycle combustion turbine plant efficiencies can be determined based on the overall production of power, gross efficiency, or on the power provided to the grid, net efficiency.

A search for efficiency information for permitted combined-cycle combustion turbine plants similar to the PEP turbines was conducted and the results are summarized in Table 5-7. Efficiency data in Table 5-7 is for permitted combined-cycle combustion turbine plants similar in size to the PEP operating with and without duct firing. Size is a significant factor in combustion turbine efficiency with efficiency increasing with increasing turbine size. While duct firing is an economic method of obtaining small capacity additions, it has a negative impact on plant efficiency that varies with duct burner size.

As shown in Table 5-7, the PEP combined-cycle combustion turbine plant efficiency compares favorably with the efficiencies of similar projects. Installation of efficient combined-cycle combustion turbines and an emission limit of 2,117,775 tons per year CO_2e emissions for the combined facility is proposed as BACT. The turbines/duct burners contribute approximately 2,112,350 tons per year of the total value presented above.

The EPA guidance document indicates a preference for output-based emission limits. An output- based emission limit, based on the heat rate, is not proposed for the turbines and duct burners due to difficulty in determining an appropriate limit that accounts for the variation in heat input and electricity output for differing ambient conditions and operating modes. This problem was discussed at length during the development of the New Source Performance Standards for Stationary Combustion Turbines (40 CFR 60, Subpart KKKK).

EPA initially proposed output-based limits on a pound per megawatt-hour (lb/MWh) basis for turbine NO_X limits in 40 CFR 60, Subpart KKKK. The agency received numerous comments explaining why achievable output-based limits were difficult to set for combustion turbines. Several commenters pointed out that combustion turbines are most efficient at full load and ISO conditions, the point at which components of the turbine are best matched for efficiency. "Any reduction in load or change in atmospheric conditions causes a reduction in efficiency" (American Petroleum Institute 2005). As a result, output-based emission rates would increase at partial load conditions, even though emissions on a mass basis would not. EPA acknowledged this problem in the Preamble to the proposed rule: "… at part- loads there may be a concern about higher output-based NO_X levels emitted due to lower thermal efficiencies." (70 Federal Register 8319, February 18, 2005). The increase in output-based emissions at partial loads with no increase in mass emissions would be equally true for GHGs.

Commenters also pointed out an output-based limit would become untenable at extremely low or zero load conditions, which could occur at PEP, for example, for a portion of the startup sequence when the turbines may be emitting but no or very little electricity is being generated. GE drew the logical conclusion that "a standard that is predicated on the full load capability of a given gas turbine must either make an allowance for part load operation, or apply a limit that is so high as to be of no consequence at full load (and in essence hollow as a regulatory imposition)" (GE 2005, *Comments of General Electric Company on the Proposed Standards of Performance for New Stationary Combustion Turbines*, *EPA-HQ-OAR-0490-0199*).

With respect to 40 CFR 60, Subpart KKKK, EPA acknowledged the commenters conclusions regarding the difficulty in setting achievable output-based limits for combustion turbines and ultimately gave owners/operators of affected facilities the choice of meeting either concentration-based or output- based limits.

In California, there are three (3) primary regulatory programs which address GHG emissions:

1. California Global Warming Solutions Act of 2006 (AB32) – this act requires the California Air Resources Board (CARB) to enact standards that will reduce GHG emissions to 1990 levels. Electricity production facilities are specifically regulated in the Act.
2. California Code of Regulations, Title 17, subchapter 10, Article 2, Sections 95100 et seq. – which provides the implementing regulations for AB32 (noted above).
3. California Code of Regulations, Title 20, Section 2900 et.seq. – which delineates the CPUC decision #D0701039 pursuant to proceeding #R0604009. This decision prohibits utilities from entering into long-term contracts with any base load facility that does not meet a GHG emission standard of 0.5 metric tons of CO_2 per megawatt-hr (or 1,100 lbs of CO_2 per megawatt-hr).

Table 5-7, in addition to showing plant efficiency comparisons also shows the GHG performance levels as they relate to the CPUC performance standard for a number of recently permitted combined-cycle facilities.

A BACT limit must not be higher than an applicable NSPS emission limit. NSPS Subpart TTTT (which will become effective on or about October 3, 2015 will establish the CO_2 limit for base load combujstion turbines at 1,000 lbs CO_2/MWh-gross.

The applicant is selecting the following as BACT for GHGs from the combustion turbines: (1) use of clean fuels (natural gas) in the turbines and duct burners, (2) compliance with the NSPS performance standard of 1,000 lbs CO_2 per MWh-gross, (3) limiting annual CO2e emissions from the turbines and duct burners to 2,112,350 tons per year. This BACT limit also complies with the CPUC performance standard.

Table 5-7
Heat Rate Efficiency and GHG Performance Data

Plant Name	Heat Rate, Btu/kWh	Energy Output, GWh and Data Year	~Lbs CO_2/MWh
Oakley GS	6779	5300 (2009)	785
Gateway GS	7123	2490 (2009)	832
Los Medanos GS	7184	3395 (2009)	838
Delta EC	7308	5014 (2009)	851
La Paloma GS	7172	6185 (2008)	862
Pastoria EF	7025	4905 (2008)	845
Sunrise Power	7266	3605 (2008)	873
Palmdale Hybrid Facility	6970	4993 (2010)	814
Proposed PEP	**6733**	**5315**	**795**
CPUC Performance Standard	**-**	**-**	**1,100**
Notes: Ref: CEC, FSA for PHPP, 700-2010-001, December 2010, GHG Tables 4 and 5.			

5.5 AUXILIARY BOILER NO_X ANALYSIS

This project includes one auxiliary boiler rated at 110 MMBtu/hr that will operate a maximum of 4884 hours per year (hr/yr). The boiler will be equipped with ultra-low NO_X burners and flue gas recirculation that are integral to the boiler design and function. The BACT analysis for NO_X emissions from the auxiliary boiler is presented in this section.

Step 1: Identify All Control Technologies

The following control methods have been identified for reducing NO_X emissions from the natural- gas fired auxiliary boiler:

- SCR;
- SNCR;
- Ultra-low NO_X burners;
- Flue gas recirculation (FGR); and
- Low NO_X burners.

SNCR is a post-combustion control method in which ammonia or urea is injected into the exhaust stream, reducing NO_X to nitrogen and water. SCR is similar to SNCR in that it is a post-combustion NO_X control method in which ammonia is injected into the exhaust stream. However, SCR systems use a catalytic reactor to overcome the temperature and residence issues that can occur with SNCR.

Ultra-low NO_X burners and low NO_X burners are designed to reduce thermal NO_X formation. This is accomplished using designs such as staged air burners, staged fuel burners, pre-mix burners, internal recirculation, and radiant burners. These burners may be used by themselves or in conjunction with FGR. FGR re-circulates a portion of the combustion exhaust stream back to the combustion zone. This reduces thermal NO_X by reducing peak temperature and available oxygen.

Step 2: Eliminate Technically Infeasible Options

All of the identified control options are technically feasible for the PEP auxiliary boiler.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

SCR systems can achieve NO_X control efficiencies of 90% or greater (ICAC 2010, *"NO_X Controls Technologies". Institute of Clean Air Companies, Inc.*). SNCR reduction levels range from 30% to 75% (ICAC 2010). Ultra-low NO_X burners are guaranteed with NO_X exhaust gas concentrations of 9 ppmv. Low NO_X burners achieve NO_X gas concentrations of 30 ppmv. FGR is often incorporated into ultra-low NO_X and low NO_X burners, including the PEP auxiliary boiler burners, and will not be considered further as a separate control option.

The control effectiveness ranking for auxiliary boiler NO_X controls is:

1) SCR;
2) SNCR;
3) Ultra-low NO_X burners; and
4) Low NO_X burners.

Step 4: Evaluate Most Effective Controls and Document Results

Ultra-low NO_X burners and FGR (9 ppm @ 3% O_2) are proposed as the basis for BACT for the auxiliary boiler. The higher ranked control options have extreme economic impacts and are not cost effective in this case. The auxiliary boiler is being permitted to operate only 4884 hr/yr, which results in annual NO_X emissions of only 2.95 tpy.

A 2008 document by the Northeast States for Coordinated Air Use Management (NESCAUM 2008) estimated the capital cost of industrial boiler SNCR at $5,372 per MMBtu/hr (NESCAUM 2008, *Applicability and Feasibility of NOx, SO2, and PM Emission control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers*). Using only the capital costs, and a NOx reduction of 67% (9 ppm to 3 ppm), results in an incremental cost effectiveness value in excess of $250,000 per ton for SNCR. This is much higher than is normally considered reasonable for BACT.

The same document contains an estimated capital cost for SCR of $9,566 per MMBtu/hr (NESCAUM 2008). Using only the capital costs, and a NOx reduction of 78% (9 ppm to 2 ppm), an incremental cost effectiveness value in excess of $400,000 per ton was calculated for SCR. This is much higher than is normally considered reasonable for BACT. The applicant has prepared a cost estimate for the proposed aux boiler for SCR using a scale up of data presented for the Oakley GS aux boiler (see Appendix D). This data indicates an SCR application cost effectiveness value of ~$58,100 per ton reduced. Although lower than the NESCAUM value, this value is also well above the typical cost effectiveness range for NOx for small auxiliary boilers.

Several air quality agencies in California have published BACT guidelines for several size ranges of natural gas fired boilers. Boilers in the size range and operational scenario as that proposed by PEP are generally required to achieve a NOx limit of 9 ppm (3% O_2).

Step 5: Select BACT

SCR, and SNCR are eliminated as BACT because of high cost impacts. Purchase of an auxiliary boiler with ultra-low NO_X burners and FGR designed to achieve a 9 ppmv NO_X concentration in the exhaust gas, and operation limited to 4884 hours per year, are proposed as the basis for BACT for the auxiliary boiler. The emission rate corresponding to 9 ppmv NO_X is 0.011 lb/MMBtu.

A BACT limit must not be higher than an applicable NSPS emission limit. The auxiliary boiler will be an affected facility under 40 CFR 60, Subpart Db, “Standards of Performance for Industrial- Commercial-Institutional Steam Generating Units.” Subpart Db does include a NO_X emission limit for natural gas-fired steam generators at a level of 0.20 lbs/mmbtu. The BACT level of 0.011 lbs/mmbtu is well below the NSPS limit.

5.6 AUXILIARY BOILER CO AND VOC ANALYSIS

The BACT analysis for CO and VOC emissions from the auxiliary boiler is presented in this section.

Step 1: Identify All Control Technologies

The following control methods have been identified for reducing CO and VOC emissions from the auxiliary boiler;

- Oxidation catalyst; and
- Good combustion practices.

Step 2: Eliminate Technically Infeasible Options

The operating temperature window for oxidation catalysts is from 500^{O}F to 1100^{O}F (NJDEP 2004, *State of the Art (SOTA) Manual for Stationary Combustion Turbines*, *2nd Revision*). The auxiliary boiler exhaust temperature of ~300^{O}F is outside this range and use of an oxidation catalyst is not considered feasible for the auxiliary boiler.

Notwithstanding the above, the applicant has prepared a cost estimate for the proposed aux boiler for a CO catalyst using a scale up of data presented for the Oakley GS aux boiler (see Appendix D). This data indicates a CO catalyst application cost effectiveness value for CO of ~$9,700 per ton reduced, and a cost effectiveness value for VOC of $85,000 per ton reduced. These values are well above the typical control cost ranges for CO and VOC for small auxiliary boilers.

Steps 3, 4 and 5: Select BACT

Use of good combustion practices is the only remaining control option. As a result, Steps 3 and 4 are unnecessary and purchasing a boiler designed to meet an emission concentration of 50 ppmv and operation limited to 4884 hours per year are chosen as the basis for BACT for the auxiliary boiler. The boiler manufacturer's guaranteed CO emission rate corresponding to an exhaust concentration of 50 ppmv is 0.037 lb/MMBtu. Annual CO emissions are estimated to be 9.94 tpy. The boiler manufacturer's guaranteed VOC emission rate corresponding to an exhaust concentration of 15 ppmv is 0.006 lb/MMBtu. Annual VOC emissions are estimated to be 1.61 tpy.

A BACT limit must not be higher than an applicable NSPS emission limit. The auxiliary boiler will be an affected facility under 40 CFR 60, Subpart Db, "Standards of Performance for Industrial- Commercial-Institutional Steam Generating Units." However, Subpart Db does not include an emission limit for either CO or VOC for natural gas-fired steam generators.

5.7 AUXILIARY BOILER /PM_{10}/$PM_{2.5}$ ANALYSIS

The BACT analysis for PM/PM_{10}/$PM_{2.5}$ emissions from the auxiliary boiler is presented in this section.

Step 1: Identify All Control Technologies

PM_{10}/$PM_{2.5}$ emissions from combustion of natural gas are low and the concentration in the exhaust flow is also low, making it very difficult to control emissions from natural gas-fired boilers. For these reasons, add-on control devices such as scrubbers, ESPs, and fabric filters have not been demonstrated in practice on gas-fired boilers (SJVUAPCD 2008) and are not considered available for the auxiliary boiler. Data presented in (AECOM 2010, *PHPP PSD Application Supplemental Information, Section 8, BACT*) indicates that control cost effectiveness for PM control devices on auxiliary boilers for technologies such as ESPs and fabric filters would be in excess of $1,000,000 per ton removed. This value is well in excess of established cost effectiveness values for PM.

The use of natural gas can also minimize particulate sulfate emissions and is an available control option for the auxiliary boiler.

Steps 3, 4 and 5: Select BACT

Use of clean fuel is the only available control option for the PEP natural gas-fired auxiliary boiler. Therefore, Steps 2 through 4 are unnecessary and the use of natural gas is chosen as the basis for PM_{10}/$PM_{2.5}$ BACT, with a proposed limit of 0.007 lb/MMBtu based on the manufacturer's guarantee.

A BACT limit must not be higher than an applicable NSPS emission limit. The auxiliary boiler will be an affected facility under 40 CFR 60, Subpart Db, "Standards of Performance for Small Industrial- Commercial-Institutional Steam Generating Units." However, Subpart Db does not include particulate matter emission limits for natural gas-fired steam generators.

5.8 AUXILIARY BOILER GHG BACT ANALYSIS

The BACT analysis for GHG emissions from the auxiliary boiler is presented in this section.

Step 1: Identify All Control Technologies

There are no add-on control options for GHG emissions from non-electrical generation boilers. There are options that increase the efficiency of boilers thereby reducing emissions by reducing fuel use. Equipment and actions that increase boiler efficiency are:

- Electronic ignition;
- Optimization of excess air;
- Stack gas heat recovery (air preheaters and economizers);
- Blowdown waste heat recovery;
- Blowdown optimization; and
- Proper boiler maintenance.

Electronic ignition eliminates the need for pilot light fuel combustion.

Excess air optimization balances the heat losses associated with heating combustion air in excess of stoichiometric conditions while providing sufficient combustion air to avoid excess CO emissions.

Air preheaters recover stack gas heat and use it to heat the incoming combustion air. Economizers recover stack gas heat and use it to pre-heat boiler feed water. The proposed boiler will have a non-condensing economizer but no air pre-heater.

Blowdown waste heat recovery systems reduce losses associated with the energy contained in the hot water and solid particles discharged during blowdown. The recovered heat is used to pre-heat boiler feed water.

Blowdown optimization balances the need to control solids with the waste heat lost in the blowdown. Excessive blowdown reduces boiler efficiency while insufficient blowdown may lead to deposits or carryover.

Proper boiler maintenance keeps boiler efficiency high. Periodic boiler tune-ups ensure that proper excess air control is maintained. Cleaning heat transfer surfaces avoids reductions in heat transfer and increased fuel use caused by scaling. Inspections to identify repair problems with steam distribution equipment, steam traps, and piping insulation assist in avoiding energy losses and increased fuel use.

Step 2: Eliminate Technically Infeasible Options

In this step each option listed in Step 1 is reviewed to determine if it is feasible for the project under review. All options listed in Step 1 are technically feasible for the PEP auxiliary boiler.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

An EPA Climate Leaders document (EPA 2008b, *Climate Leaders Greenhouse Gas Inventory Protocol Offset Project Methodology for Project Type: Industrial Boiler Efficiency (Industrial Process Applications)* contains efficiency improvement ranges for the efficiency options under consideration. These options are presented in Table 5-8.

Table 5-8
Auxiliary Boiler Efficiency Options

Efficiency Option	Efficiency Range,%
Non-condensing economizer	1-7
Condensing economizer	1-2
Air preheaters	1-2
Blowdown waste heat recovery	1-2
Optimize excess air	1
Blowdown optimization	Avoids reduction in efficiency
Proper maintenance	Avoids reduction in efficiency
Notes:	

The various efficiency improvement options can be implemented individually or in combination. This includes implementation of all of the options together with the exception of the economizer. A non- condensing and condensing economizer could not both be used at the same time.

Step 4: Evaluate Most Effective Controls and Document Results

In this step the environmental, energy, and economic impacts of the options are considered. There are no negative energy impacts associated with any of the options. All of the efficiency options save energy by increasing efficiency and reducing fuel use.

The only possible environmental impacts are increased NO_X emissions with air preheaters (proposed boiler will not have an air pre-heater), increased CO emissions with excess air control, and increased wastewater generation with blowdown control. For excess air control and boiler blowdown, optimization to minimize the environmental impacts, while achieving the desired boiler efficiency, is an integral part of the option.

Air preheaters can impact NO_X emissions by increasing the peak flame temperatures in the boiler. In conjunction with low NO_X burners, boilers can be equipped with flue gas recirculation (FGR) to control NO_X emissions. FGR is used to lower peak flame temperature. Boilers are designed for optimum flame temperature for proper boiler operation and to minimize NO_X emissions. An air preheater in combination with low

NO_X burners and FGR would adversely impact boiler flame temperature and increase NO_X emissions.

For the options other than blowdown optimization and proper maintenance, the cost of additional equipment presents an economic impact that is offset by the decreased fuel consumption that results from increased efficiency.

Step 5: Select BACT

The auxiliary boiler will be equipped with the following energy efficiency measures:

- Electronic ignition
- Optimization of excess air using ultra-low NO_X burners and FGR
- Non-condensing economizer

Use of these efficiency measures result in a gross boiler efficiency (per the manufacturer) when new of 83.0 - 83.7% (HHV).

Based on the use of the identified boiler efficiency measures that provide the auxiliary boiler with a gross efficiency of 83.0 - 83.7% (HHV), an emission limit of 31,431 tons CO_2e per year reflecting use of these energy efficiency measures and maximum operation of 4884 hours per year is proposed as BACT for GHG emissions. An output based emission limit is not proposed given the operation of the auxiliary boiler in a combination of the three (3) proposed operating regimes and various load scenarios.

5.9 EMERGENCY FIRE PUMP AND EMERGENCY GENERATOR NO_X ANALYSIS

The project includes a diesel-fired, 140 horsepower (Tier 3), emergency fire pump that will operate no more than 52 hr/yr in non-emergency service, and a 2011 horsepower (Tier 2) emergency electrical generator that will operate no more than 26 hr/yr in non-emergency service. The BACT analysis for NO_X emissions from the engines is presented in this section.

Step 1: Identify All Control Technologies

The proposed IC engines are both diesel fuel fired using California certified ultra-low sulfur diesel. The following control options have been identified for the diesel-fired engines:

- SCR
- NSCR (NOx Tech)
- Water injection and
- Combustion controls.

NO_X adsorbers, also called lean NO_X traps, and Lean NO_X catalyst controls are post-combustion control devices that have been developed for controlling NO_X from on-road diesel engines. There has been no use of NO_X adsorbers on stationary diesel engines nor have there been any studies of their use on stationary engines (EPA 2010b, *Alternative Control Techniques Document: Stationary Diesel Engines, Final Report*). Lean NO_X catalyst controls have also not been used on stationary diesel engines (EPA 2010b). As such, NO_X adsorbers and lean NO_X catalyst controls are not considered available for use on the PEP diesel engines.

Step 2: Eliminate Technically Infeasible Options

SCR, SNCR, water injection, and combustion controls are considered feasible for the PEP fire pump and emergency generator engines.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The next step is to rank the control technologies by effectiveness. The post-combustion control options, SCR and SNCR, can achieve greater than 90% NO_X control efficiencies (Alpha-Gamma Technologies, Inc. 2005*, Memorandum from Tanya Parise (Alpha-Gamma Technologies, Inc.) to Sims Roy (US EPA) regarding "NO_X Control Technologies for Stationary Diesel ICE*). Combustion control can reduce emissions by as much as 80% (Alpha-Gamma Technologies, Inc. 2005) and water injection reduces emissions by 25%-35%. Table 5-9 shows the control effectiveness ranking.

Table 5-9
Diesel Engine NOx Control Technology Ranking

Control Option	Control Efficiency, %
Post-combustion add-on systems	>90%
Combustion controls	80%
Water injection	25-35%
Notes:	

Step 4: Evaluate Most Effective Controls and Document Results

Given the limited hours of operation and corresponding small annual NO_X emissions, i.e., (0.022 tpy for the fire pump, and 0.218 tpy for the generator enigne), the cost impacts associated with post-combustion NO_X controls are prohibitive. Cost information obtained has been obtained from available references and used to calculate cost effectiveness values for the fire pump engine. An emission control efficiency of 95% was assumed for the post-combustion control options. The cost effectiveness information for the post combustion controls is summarized in Table 5-10.

Table 5-10
Diesel Engine Post Combustion NOx Control Cost

Control Option	Annualized Cost, $/ton	Emission Reduction, tpy	Cost Effectiveness, $/ton
Fire Pump			
SCR @ 90%	$9520	0.0198	$480,000
SNCR @90%	$1427	0.0198	$72,000
Emergency Generator			
SCR @ 90%	$9520	0.196	$48,500
SNCR @90%	$1427	0.196	$7,281
Notes: EPA's *Alternative Control Techniques Document: Stationary Diesel Engines*			

As indicated by the values in Table 5-10, the application of post-combustion control to the fire pump and emergency generator engines would have a large economic impact. Data presented in (AECOM 2010, *PHPP PSD Application Supplemental Information, Section 8, BACT*) indicates that control cost effectiveness for NOx control devices on diesel engines for technologies such as SCR ranges from $242.400 to $396,800 per ton removed for the generator and fire-pump respectively. Additionally, (AECOM 2010) indicates that NOx control costs associated with NOx Adsorbers and CDPF technologies ranges from $13,400 to $22,000 for the generator and fire-pump respectively. These values are well in excess of established cost effectiveness values for NOx.

Step 5: Select BACT

The final step in the top-down BACT analysis process is to select BACT. Limiting hours of operation to 26 and 52 hours per year respectively for the generator and fire pump engines, use of ultra-low sulfur fuel, modern engine design, and compliance with current EPA Tiered emissions standards are proposed as BACT. Post-combustion controls are not chosen as BACT because of high cost impacts.

A BACT limit must not be higher than an applicable NSPS emission limit. Emissions limits from 40 CFR 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines," will apply to the emergency fire pump. The fire pump engine chosen for the project will meet the combined NO_X and non-methane hydrocarbon emission limit of 3.0 g/hp-hr applicable to engines with a rated horsepower between 100 and 175 installed after 2010. The generator engine currently complies with the emissions standards for NOx as found in 40 CFR 89.112.

5.10 EMERGENCY FIRE PUMP AND EMERGENCY GENERATOR CO AND VOC ANALYSIS

The BACT analysis for CO emissions from the diesel fired IC engines is presented in this section.

Step 1: Identify All Control Technologies

Control options identified for CO and VOC emissions from diesel-fired internal combustion engines are:

- Oxidation catalysts;
- Catalyzed diesel particulate filters (CDPF);
- Flow through filters; and
- Combustion controls.

Lean NO_X catalyst controls are post-combustion control devices that have been developed for controlling emission from on-road diesel engines. Lean NO_X catalysts have not been used on stationary diesel engines (EPA 2010b) and are not considered available for this analysis.

Step 2: Eliminate Technically Infeasible Options

The identified control options are technically feasible for the diesel IC engines.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The post-combustion control methods, oxidation catalysts, CDPF, and flow through filters, identified as feasible control options for the diesel IC engines, are the top ranked controls.

Oxidation catalysts are less effective when used on emergency equipment than when used on equipment that is operated in a more continuous manner (ICCR 1998b, *Recommended Subcategories and MACT Floors for Existing Stationary Reciprocating Internal Combustion Engines (RICE).* Oxidation catalysts provide control once the effective temperature is reached. The emergency fire pump will only be operated for brief periods of time. This means that during a portion of the operation, the oxidation catalysts may not have reached temperature and will not be providing control. It is for this reason that oxidation catalysts are seldom used on emergency equipment. For purposes of this analysis, it has been assumed that an oxidation catalyst will provide control throughout engine operation and will provide a 90% control efficiency.

CDPF can provide CO, PM, and VOC control. As with oxidation catalysts, exhaust temperatures are important to the operation of CDPF. The exhaust temperature must be sufficient to facilitate regeneration. This may be a problem with an emergency use engines that operate infrequently and for short periods of time. However, as with oxidation catalysts, CDPF has been assumed to be a feasible option providing CO emission control during engine operations. CDPF can provide a CO emission reduction of 90% (EPA 2010b).

Flow through filters can control CO, PM, and VOCs. One manufacturer has demonstrated CO control of 90% (EPA 2010b).

Step 4: Evaluate Most Effective Controls and Document Results

The top ranked technologies are the use of oxidation catalysts, CDPF, or a flow through filter. Because of the low emissions associated with the diesel IC engines, cost impacts associated with the use of these controls are very high.

EPA's *Alternative Control Techniques Document: Stationary Diesel Engines* contains cost information for diesel oxidation catalysts, CDPF, and flow through filters (EPA 2010b). This information has been used to calculate a cost effectiveness value for their use to control CO and VOC emissions from the engines. The calculated cost effectiveness values are:

<u>Fire Pump</u>

Diesel oxidation catalyst: $7150/ton CO, and $27,200/ton VOC;

CDPF: $18,300/ton CO; and $131,600/ton VOC;

Flow through filters: >$15,000/ton CO, no data for VOC.

<u>Emergency Generator</u>

Diesel oxidation catalyst: $4140/ton CO, and $11,500/ton VOC;
CDPF: $9837/ton CO, and $78,500/ton VOC
Flow through filters: >$41,000/ton CO, and no data for VOC.

These cost values are much higher than what is typically considered reasonable for BACT.

Step 5: Select BACT

The final step in the top-down BACT analysis process is to select BACT. Limiting hours of operation to 26 and 52 hours per year respectively for the generator and fire pump engines, use of ultra-low sulfur fuel, modern engine design, and compliance with current EPA Tiered emissions standards are proposed as BACT for CO and VOC. Oxidation catalysts, CDPF, and flow through filters have not been selected as CO and VOC BACT because of high cost impacts.

A BACT limit must not be higher than an applicable NSPS emission limit. The emergency fire pump will be an affected facility under 40 CFR 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines." The fire pump engine chosen for the project will meet the CO limit of 3.7 g/hp-hr applicable to engines with a rated hp between 100 and 175, as well as the NMHC limit. The generator engine currently complies with the CO and VOC standards in 40 CFR 89.112.

5.11 EMERGENCY FIRE PUMP AND EMERGENCY GENERATOR $PM_{10}/PM_{2.5}$ ANALYSIS

The BACT analysis for $PM_{10}/PM_{2.5}$ emissions from the diesel IC engines is presented in this section.

Step 1: Identify All Control Technologies

Methods identified for controlling $PM_{10}/PM_{2.5}$ emissions from diesel-fired internal combustion engines are:

- Diesel particulate filters;
- CDPF;
- Flow through filters; and
- Low sulfur fuel.

Step 2: Eliminate Technically Infeasible Options

All of the identified control options are feasible for the PEP diesel IC engines.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

The control ranking is presented in Table 5-11.

Table 5-11
Control Option Ranking for Diesel Engine PM

Control Option	Control Efficiency, %
Particulate filters	90
Catalyzed particulate filters	90
Flow through filters	75
Low sulfur fuel vs. ultra-low sulfur fuel	LSF at 0.05% S wt. ULSF at 0.0015% S wt.
Notes: ULSF required in California, therefore no reduction is calculated.	

Step 4: Evaluate Most Effective Controls and Document Results

The $PM_{10}/PM_{2.5}$ emissions from the diesel engines are very small due to the limited hours of operation, i.e., 0.002 and 0.005 tpy for the fire pump and generator respectively. Installation and use of add-on control equipment for such small emissions is extremely cost prohibitive. Cost information from EPA's *Alternative Control Techniques Document: Stationary Diesel Engines* has been used to calculate cost effectiveness values for the add-on control options. The resulting values are:

- Diesel oxidation catalyst: $125,700/ton-generator; and $127,900/ton-fire-pump
- CDPF: $99,700/ton-generator; and $57,000/ton-fire-pump
- Flow through filters: $50,510/ton-generator; and $76,900/ton-fire-pump

These cost values are much higher than what is typically considered reasonable for BACT.

Step 5: Select BACT

The final step in the top-down BACT analysis process is to select BACT. Limiting hours of operation to 26 and 52 hours per year respectively for the generator and fire pump engines, use of ultra-low sulfur fuel, modern engine design, and compliance with current EPA Tiered emissions standards are proposed as PM BACT. Diesel particulate filters, catalyzed diesel particulate filters, and flow through filters are rejected as BACT because of high cost impacts.

A BACT limit must not be higher than an applicable NSPS emission limit. Emissions limits from 40 CFR 60, Subpart IIII, “Standards of Performance for Stationary Compression Ignition Internal Combustion Engines,” will apply to the emergency fire pump. The fire pump engine chosen for the project will meet the particulate matter 0.22 g/hp-hr limit applicable after 2010 to engines with maximum power between 100 and 175 hp. In addition, Subpart IIII requires the use of ultra-low sulfur fuel. The fuel used in the emergency fire pump engine will meet the Subpart IIII requirements. The generator engine currently meets the emissions standards in 40 CFR 89.112.

5.12 EMERGENCY FIRE PUMP AND EMERGENCY GENERATOR GHG ANALYSIS

The BACT analysis for GHG emissions from the emergency diesel engines is presented in this section.

Step 1: Identify All Control Technologies

There are no add-on options for control of GHG emissions from non-electric generation reciprocating engines. The only option identified that increases engine efficiency, reducing the fuel used and the emissions generated, for four-stroke, diesel-fired engines is the use of turbocharging and intercooling.

A turbocharger is an intake air compressor that forces more air and fuel into the cylinders increasing engine output. The discharge air from the turbocharger, the intake air for the engine, is heated by the compression. This reduces the air density and limits the mass of the intake air to the engine. To compensate for this increase in air temperature, a heat exchanger is used to cool the air between the turbocharger and the engine. This heat exchanger is referred to as an intercooler or aftercooler.

Step 2: Eliminate Technically Infeasible Options

In this step each option listed in Step 1 is reviewed to determine if it is feasible for the project under review. Turbocharging and after/intercooling are feasible for the PEP diesel engines.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

In this step the control options are ranked. The only two options identified are the use of turbocharging and after/intercooling to increase engine efficiency and use of an engine without turbocharging and afterintercooling. Obviously, use of a more efficient engine equipped with turbocharging and after/intercooling is the higher ranked option.

Step 4: Evaluate Most Effective Controls and Document Results

In this step the environmental, energy, and economic impacts of the options are considered. The highest ranked option is the use of turbocharging and after/intercooling to increase engine efficiency. The use of turbocharging and after/intercooling does not have any associated environmental impacts. Turbocharging and after/intercooling increase engine efficiency and therefore have a positive energy impact. There are no significant economic impacts with the use of turbocharging and after/intercooling.

Step 5: Select BACT

The PEP diesel fired IC engines are equipped as follows: the fire pump engine is turbocharged only, and the larger emergency generator is turbocharged and after-cooled. The efficiency of the engines is reflected in the respective fuel use rates. The engines will have a fuel input rates of 9.2 (fire pump) and 104.6 gallons per hour (generator) respectively at full load.

The final step in the top-down BACT analysis process is to select BACT. Limiting hours of operation to 26 and 52 hours per year respectively for the generator and fire pump engines, use of ultra-low sulfur fuel, modern engine design, and compliance with current EPA Tiered emissions standards are proposed as BACT.

5.13 COOLING TOWER $PM_{10}/PM_{2.5}$ ANALYSIS

The PEP facility is being designed, and will be constructed and operated using dry cooling technology. The BACT analysis for $PM_{10}/PM_{2.5}$emissions which follows simply describes the lower ranking technologies for purposes of completeness.

Step 1: Identify All Control Technologies

The following control methods have been identified for reducing $PM_{10}/PM_{2.5}$ emissions from cooling towers:

- Wet cooling with drift eliminators;
- Dry cooling; and
- Hybrid cooling.

Wet cooling condenses steam in water-cooled condensers. Cooling is achieved by the evaporation of a fraction of the circulating water flow. Some of the water becomes entrained in the air passing through the tower. The entrained water droplets are referred to as drift. Particulate matter emissions come from the solids dissolved in the water droplets. Drift eliminators are used to reduce drift by causing the water droplets to change direction while passing through the eliminators. Drift eliminator performance is described in terms of a percentage of the circulating water.

Dry cooling uses air cooled condensers. Steam is condensed inside tubes using cooled air blown across the tubes. The only direct emissions that can occur from dry cooling are entrainment of dust by the fans.

Hybrid cooling includes components of both wet and dry cooling. These systems use less water than wet cooling with greater plant efficiency than dry cooling.

Step 2: Eliminate Technically Infeasible Options

The three identified control options are technically feasible for the project.

Step 3: Rank Remaining Control Technologies by Control Effectiveness

Wet and hybrid cooling generate direct particulate matter emissions. Although dry cooling does not generate drift emissions, the California Energy Commission has indicated that particulate emissions do occur with dry cooling, i.e., re-entrainment, the dry cooling system fans can suspend particles in the area of the cooling structures. Given that estimating the extent of the emissions generated in this manner would be difficult, and that much of the area around the cooling structures would be paved, for purposes of this analysis, these emissions are considered to be zero.

Table 5-12
Cooling Tower Technology Ranking

Cooling Tower Design	Emissions Ranking
Dry Cooling	Zero emissions –Ranking Position 1
Hybrid Cooling	Low emissions – Ranking Position 2
Wet Cooling	Moderate emissions – Ranking Position 3
Notes:	

As indicated in Table 5-12, the lowest $PM_{10}/PM_{2.5}$ emissions are for dry cooling (basically zero emissions) and the highest are for wet cooling.

Step 4: Evaluate Most Effective Controls and Document Results

The energy, environmental, and economic impacts associated with the cooling options are evaluated below.

Energy Impacts

There are two energy-related impacts associated with cooling systems:

- Parasitic load
- Plant efficiency

The first of these impacts, parasitic load, deals with the energy used by the cooling system itself. The second, plant efficiency, deals with the effect that the cooling system has on plant power production.

Parasitic power is the power needed by the cooling system for fans and pumps. A dry cooling system requires a greater air flow than a wet or hybrid system. This air flow is provided by fans. The difference in fan power required for dry cooling is offset somewhat by the water pumping requirements of a wet cooling system. A hybrid system requires less fan power than a dry system and less water pump power than a wet system.

Generally, the hybrid cooling system has the highest parasitic power requirement followed by wet cooling. Advances in air cooled condenser design over the last five years have lowered the parasitic demand of dry cooling and the dry cooling system has the lowest parasitic power demand.

In addition to the parasitic power requirements, the cooling system used for a combined-cycle plant directly affects the efficiency of the steam turbine generator and the amount of power that can be produced. A plant configured with wet cooling is more efficient and can produce more power than a plant configured with hybrid or dry cooling.

The Arizona Corporation Commission, Utilities Division Staff in a document titled *Use and Associated Costs of Wet, Dry, and Hybrid Cooling Systems in New Power Plants*, dated April 14, 2010 addressed these difference concluding, “Power plants operating at high thermal efficiencies require less cooling water and cost less to operate. High thermal efficiencies are not as easily achieved with dry cooling systems because ambient dry bulb temperatures are always higher than ambient wet bulb temperatures” (Arizona Corporation Commission 2010, *Use and Associated Costs of Wet, Dry, and Hybrid Cooling Systems in New Power Plants*).

Steam turbines extract power from steam as it passes from high pressure and high temperature to lower pressure and lower temperature. After the turbine, the steam goes to a condenser. The energy available to drive the steam turbine in a combined-cycle system is directly affected by the steam turbine exhaust pressure. The steam turbine exhaust pressure is a function of the condenser temperature, which in turn is dependent on the temperature of the cooling water or air used to absorb the heat from the steam. A lower temperature at the condenser results in a lower turbine exhaust pressure. Above a practical lower limit, the lower the exhaust pressure, the greater the energy that can be produced.

For wet cooling towers, the temperature at the cooling tower outlet is the same as the condenser cooling water inlet temperature. The cooling water outlet temperature is a function of the wet bulb temperature of the ambient air. The wet bulb temperature takes into account the cooling effect of water evaporation and is a function of the ambient air temperature and humidity. Because no evaporation of water is involved with dry cooling, the performance of the cooling system is a factor of the ambient air temperature only. The ambient air temperature is also referred to as the dry bulb temperature.

The wet bulb temperature is always equal to or less than the dry bulb temperature. This means that the energy that can be produced from a plant configured with dry cooling will always be less than or equal to the power that can be produced by a plant configured with wet cooling. A system configured with a hybrid cooling system will produce more power than a dry system and less than a wet system.

As the ambient temperature increases, the difference in wet bulb and dry bulb temperatures increases. Given the dry climate and high temperatures experienced in Arizona, performance penalties associated with the use of dry or hybrid cooling are even greater than what would be encountered in a cooler, more humid climate.

The efficiency penalty associated with dry cooling increases the fuel required to produce power and reduces the peak power output that can be generated.

Environmental Impacts

There are environmental impacts associated with wet, hybrid, and dry cooling systems. Wet cooling systems have greater water consumption, greater wastewater production, and can generate visible plumes. A dry cooling system has greater noise impacts, greater visual impacts because the structures are larger, and, in terms of lb/MWh, greater emissions of pollutants other than $PM/PM_{10}/PM_{2.5}$. A hybrid system shares the environmental impacts of both wet and dry cooling.

Wet, hybrid, and dry cooling configurations require water for combustion turbine inlet evaporative cooler blowdown, HRSG blowdown, and miscellaneous other streams. Most of the water consumption in a wet or hybrid cooling configuration is evaporated in the cooling towers. The cooling system analysis conducted for the PEP project indicated that a dry cooling system would take approximately 3.6% of the water required for a wet cooling system and a hybrid system would take approximately 38.2% of the water required for a wet system.

Wastewater is generated regardless of the cooling configuration used. Because of the lower water use associated with dry and hybrid cooling, less wastewater would be generated and smaller evaporation ponds would be needed than for wet cooling.

Visual impacts can occur with wet cooling systems when atmospheric conditions are sufficient to make the steam plume from the towers visible. Visual impacts from dry cooling systems occur because the cooling structures are large and very tall. The structures associated with dry cooling are generally 100 to 145 feet high. Dry cooling structures are also more noticeable because the top 25-30 feet of a dry cooling tower structure appears as a solid wall (SMUD 2002, *Cosumnes Power Plant 01-AFC-19. Power Plant Cooling Analysis*). In addition to the visual impacts created by this solid wall, dispersion of emissions from the facility would be hindered under certain meteorological conditions by the wake effect created by the larger structure.

With aspects of both wet and dry cooling, hybrid cooling would have visual impacts associated with the possibility of visible plumes from the wet components and the large structure associated with the dry components.

Noise from dry cooling is also greater than noise from wet cooling. Wet cooling noise is generated by falling water, fans, and motors. Noise abatement is an integral part of the cooling tower design. Noise from dry cooling is primarily from air movement and fan motors. Dry cooling requires the movement of a large volume of air and a large number of fans are used. There are many more fans associated with dry cooling than with wet cooling. Because of the large volume of air moved, the number of fans used, and the height at which the fans would be located, the noise level beyond the plant boundary would be greater for dry cooling than for wet cooling. The noise level for hybrid cooling would be between the levels for wet and dry cooling. The PEP will be located in a semi-urban area (next to an existing Air Force base and flight facility) and the increased noise associated with dry or hybrid cooling is not expected to be noticeable and disruptive.

Plants using dry or hybrid cooling may generate more air pollutant emissions per MWh of electricity produced than wet cooling because of the energy penalty discussed earlier.

Economic Impacts

There are two areas of economic impacts associated with dry cooling and hybrid cooling:

- Increased construction and installation costs; and
- Decreased revenue.

Although the applicant understands that some economic impacts are associated with dry cooling, the lack of water supply in the project region has dictated that the facility be designed with dry cooling. The impacts of dry cooling on parasitic load, fuel use, and power sales have already been factored into the project design.

Step 5: Select BACT

For the PEP, a plant configuration using dry cooling is chosen as the basis for BACT for cooling tower PM_{10}, and $PM_{2.5}$. The choice of dry cooling was dictated by the lack of water in the project area as well as the success to date of the dry cooling systems installed on other similar power facilities in California, e.g., Colusa Generating Station located in the northern Sacramento Valley.

5.14 CIRCUIT BREAKERS GHG ANALYSIS

There will be an electrical switchyard within the PEP boundary. The switchyard will include six circuit breakers each containing 360 lbs of sulfur hexafluoride (SF_6), a potent GHG. SF_6 is a highly effective dielectric used for interrupting arcs and is the universally accepted medium for high- voltage circuit breakers (McDonald 2007, *Electric Power Substations Engineering, Second Edition*). The circuit breakers located on the PEP site will have the potential for fugitive emissions of SF_6 as a result of equipment leaks. The BACT analysis for GHG emissions from the circuit breakers is presented below.

Step 1: Identify All Control Technologies

Three control options have been identified for the SF_6 emissions from the circuit breakers.

- Use of another type of circuit breaker
  - Oil circuit breaker
  - Air blast breaker
  - Vacuum breaker
- Use of a different dielectric; and
- Use of leak detection monitoring

Air-blast, oil, and vacuum circuit breakers are three available alternative circuit breaker types. SF_6 circuit breakers provide superior performance to these alternatives (NIST 1997, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6.*). "SF_6 is about 100 times better than air for interrupting arcs" (McDonald 2007).

To reduce SF_6 emissions, other dielectric gases and mixtures of SF_6 with other gases are being investigated as replacements for SF_6 alone.

Leak detection monitoring is used to minimize emissions by identifying and repairing leaks as soon as possible.

Step 2: Eliminate Technically Infeasible Options

In this step each option listed in Step 1 is reviewed to determine if it is feasible for the project under review.

Use of vacuum circuit breakers is not a technically feasible option. The PEP will have a total of six (6) vacuum breakers as follows: 2 SF6 breakers located at the combustion turbines rated at 18kV and 325 MVA, and 4 SF6 breakers in the switchyard rated at 230 kV and 800MVA. Vacuum circuit breakers are used for medium voltage levels. Prototype large voltage vacuum circuit breakers have been developed; however, as indicated in a paper presented at the 2009 International Conference on Renewable Energies and Power Quality, “it is necessary to introduce changes in the design and the materials used to ensure the proper working of VCB [vacuum circuit breaker] at higher voltage values” (Iturregi 2009, *High Voltage Circuit Breakers: SF6 vs. Vacuum*). Vacuum circuit breakers are not available for high voltage applications and are therefore not available for the circuit breakers to be located on the PEP site.

Oil and air-blast circuit breakers are also not an available option for high voltage applications as they are no longer being offered by manufacturers (Lester 2008, *IEEE Tutorial: Design and Application of Power Circuit Breakers, Part 1 History of Circuit Breaker Standards*). Oil and air-blast circuit breakers were commonly used for voltage applications from 15 kV to 345 kV until the mid-1970s (Garzon 2002, *High Voltage Circuit Breakers, Design and Applications, Second Edition, Revised and Expanded*), but have since been replaced by SF_6 circuit breakers.

SF_6 breakers replaced oil and air-blast breakers because of their superior performance, but also because of other issues with oil and air-blast breakers. The oil breaker disadvantages were flammability and high maintenance costs. The maintenance costs were a result of oil replacement requirements. Oil in circuit breakers is degraded by small quantities of water and by carbon deposits from the carbonization that occurs when the oil comes into contact with the electric arc.

Air-blast circuit breakers require the installation of expensive compression stations, are very large, and create a very high level of noise on operation. In a document discussing possible alternatives to use of SF_6 alone, NIST stated that SF_6 is used almost exclusively because “It offers significant savings in land use, is aesthetically acceptable, has relatively low radio and audible noise emissions, and enables substations to be installed in populated areas close to the loads” (NIST 1997).

EPA’s SF_6 Emission Reduction Partnership for Electric Power Systems, a voluntary public- private partnership focused on reducing SF_6 emissions, has not advocated for a return to oil or air-blast breakers for high voltage applications, but instead has focused on leak detection and repair, education of SF_6 handlers, and replacement of older SF_6 circuit breakers with new SF_6 breakers.

Use of an alternative dielectric is not a feasible option as there are no replacement gases that have been developed. Decades of investigation have found alternatives for medium voltage electric power equipment, but no viable alternative to SF_6 for high-voltage equipment (McDonald 2007). The 2010 annual report (the most recent available) for the EPA’s SF_6 Emission Reduction Partnership for Electric Power Systems states, “Because there is no clear alternative to SF6, Partners reduce their greenhouse gas emissions through implementing emission reduction strategies …” (EPA 2011g, *SF_6 Emission Reduction Partnership for Electric Power Systems, 2010 Annual Report*).

Use of leak detection monitoring is feasible for the circuit breakers to be located at the PEP site.

Steps 3, 4 and 5: Select BACT

GHG BACT for the PEP SF_6 circuit breakers is proposed as follows:

1. Use of enclosed-pressurized circuit breakers.
2. Annual SF_6 leak rates shall not exceed 0.5% by wt.
3. The breakers will be equipped with a 10% by wt. leak detection system.