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PETITION TO AMEND

TURBINE REPLACEMENT PROJECT
INLAND EMPIRE ENERGY CENTER (01-AFC-17C)

Submitted to:

The California Energy Commission

Submitted by:

Inland Empire Energy Center LLC

Prepared by:

URS Corporation

October 7, 2014

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ACRONYMS

AB	Assembly Bill
ACFM	actual cubic feet per minute
AFC	Application for Certification
AQMP	air quality management plan
BACT	Best Available Control Technology
BAE	baseline actual emissions
CAAQS	California Ambient Air Quality Standards
CAPCOA	California Air Pollution Control Officer's Association
CARB	California Air Resources Board
CCR	California Code of Regulations
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
CPUC	California Public Utilities Commission
CT	combustion turbine
CTG	combustion turbine generator
DLN	dry low-NO_X
EIA	U.S. Energy Information Administration
EMWD	Eastern Municipal Water District
EPS	emission performance standard
ERC	Emission Reduction Credit
°F	degrees Fahrenheit
GCP	good combustion practice
GE	General Electric Company
GHG	greenhouse gas
gpm	gallons per minute
gr/scf	grains per standard cubic foot
GWP	global warming potential
HHV	higher heating value
HRA	health risk assessment
HRSG	heat recovery steam generator
H_2S	hydrogen sulfide
Hz	Hertz
IEEC	Inland Empire Energy Center
IEEC LLC	Inland Empire Energy Center, LLC
IOU	investor-owned utility
lb	pound per day
lb/day	pounds per day
lb/hr	pounds per hour
lb/MWh	pound per megawatt-hour
LORS	laws, ordinances, regulations, and standards
LTPP	Long-Term Procurement Plan
$\mu g/m^3$	micrograms per cubic meter
MMBtu/hr	million British thermal units per hour
MW	megawatt

MW-hr	megawatt-hour
MW-hr/yr	megawatt-hours per year
NAAQS	National Ambient Air Quality Standards
NH_3	ammonia
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
N_2O	nitrous oxide
NSPS	new source performance standard
NSR	New Source Review
O_2	oxygen
PAE	projected actual emissions
PAL	Plantwide Applicability Limit
PM	particulate matter
PM_{10}	particulate matter less than 10 microns in diameter
$PM_{2.5}$	particulate matter less than 2.5 microns in diameter
ppmvd	parts per million by volume, dry basis
POU	publicly owned utility
PSD	Prevention of Significant Deterioration
PTA	Petition to Amend
PTE	potential to emit
PTO	Permit to Operate
RTC	RECLAIM Trading Credit
RWRF	Regional Water Reclamation Facility
SB	Senate Bill
SCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
scf	standard cubic foot
SCR	selective catalytic reduction
SJVAPCD	San Joaquin Valley Air Pollution Control District
SO_2	sulfur dioxide
SO_X	sulfur oxides
STG	steam turbine generator
tpy	tons per year
U.S. EPA	U.S. Environmental Protection Agency
VOC	volatile organic compounds

1.0 INTRODUCTION

In accordance with Title 20, California Code of Regulations (CCR), Section 1769 (Section 1769), Inland Empire Energy Center, LLC (IEEC LLC or Applicant) submits this Petition to Amend (PTA or Petition) the IEEC's license to address proposed changes related to equipment replacement.

The IEEC is an 810-megawatt (MW) combined-cycle power plant located on approximately 46 acres in the City of Menifee, in Riverside County (see Figure 1-1). The IEEC was certified by the California Energy Commission (CEC or Commission) in December 2003 (CEC, 2003b). In March 2005, IEEC LLC filed a PTA to change the power generation configuration for the originally proposed General Electric Company (GE) 7FB combustion turbine generator (CTG) and one steam turbine generator (STG) to a new configuration using two GE S107H systems (IEEC, 2005) (2005 IEEC Amendment). Each GE S107H System has a steam turbine and gas turbine configured on a common shaft line driving a single generator. The GE S107H System included the most advanced commercially available gas turbine produced by GE Energy at that time. In June 2005 (CEC, 2005a), the Commission approved the 2005 IEEC Amendment, finding that the petition satisfied Section 1769, including that the project would comply with all applicable laws, ordinances, regulations, and standards (LORS), and that there would be no new or additional unmitigated significant environmental impacts associated with the proposed changes.

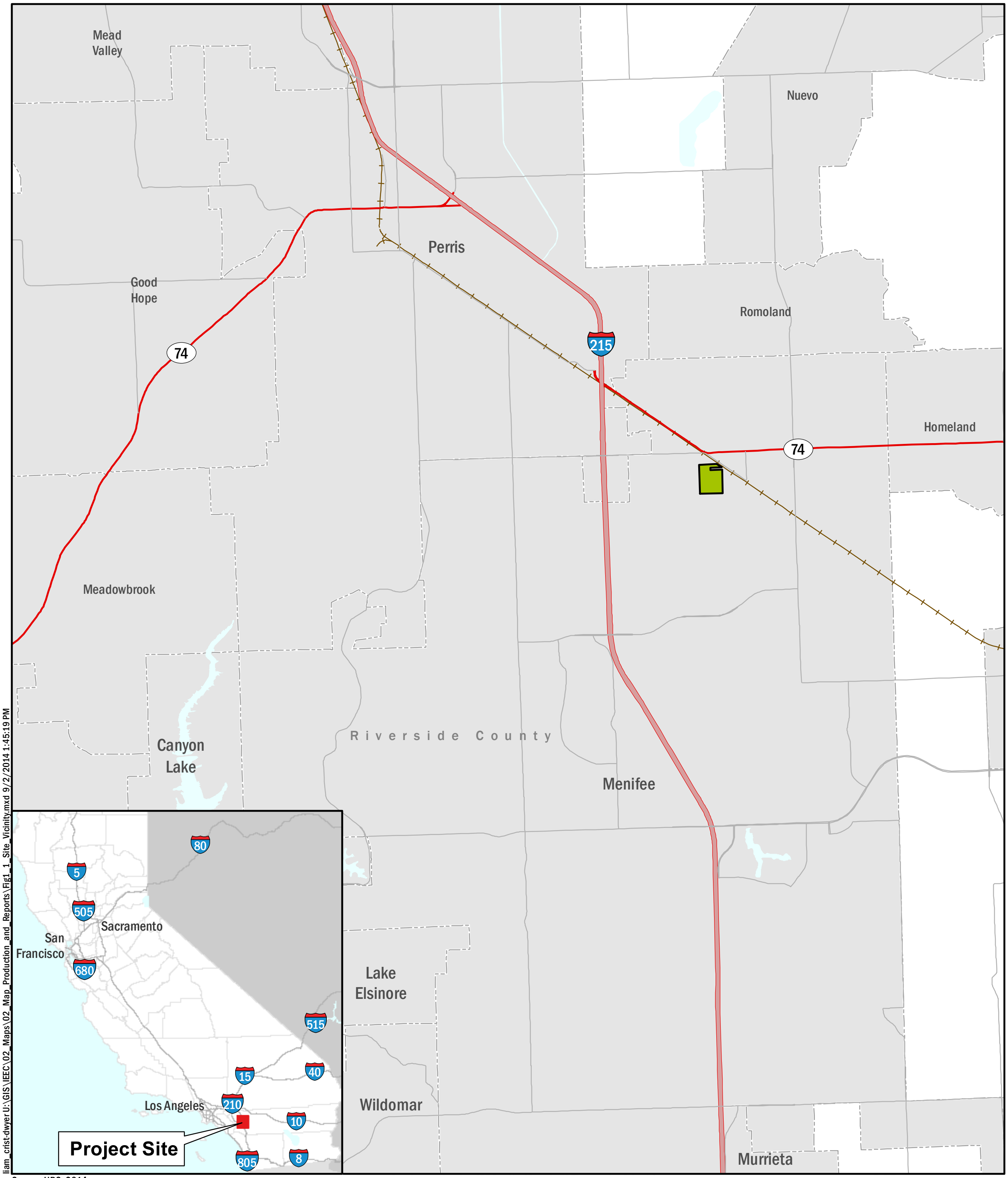
IEEC LLC began construction of both 7H units in 2005. Unit 1 commissioning activities were completed in January of 2009, with Unit 2 completed in June 2010.

In November 2009, IEEC LLC filed a PTA to modify the air quality Conditions of Certification to make them consistent with the South Coast Air Quality Management District (SCAQMD) RECLAIM/Title V permit for the IEEC (IEEC, 2009). The Commission approved the petition in December 2010 (CEC, 2010). The current version of the SCAQMD Permit to Operate (PTO) was issued in November 2012.

Applicant is submitting this PTA to replace one of the IEEC's existing GE 7H-technology gas turbines (GE S107H) with a functionally identical GE 7HA.01 gas turbine, the latest generation in H technology (Project). GE introduced the high efficiency H-class technology 10 years ago at the IEEC, and the two existing GE S107H turbines represented GE's most advanced technology at the time; they were the first installed in the United States, and the second and third installed in the world. The technology has continued to evolve, however, and the new 7HA.01 unit would provide the following benefits:

- Improved efficiency;
- Lower operation and maintenance costs; and
- Reduced water use from an air-cooled gas turbine.

The IEEC turbine replacement project provides a unique opportunity for GE to install and demonstrate performance of its new evolutionary technology at a facility in California that is wholly owned by a subsidiary of GE - IEEC LLC. GE is currently testing the 9HA (50 Hertz [Hz]) turbine at its Greenville, South Carolina full-load validation facility. The 7HA.01 (60 Hz) turbine will receive the same full-load validation in Greenville, South Carolina in 2015. The Project objective for Applicant is to have the new 7HA.01 turbine operating and in service at IEEC by summer 2016, and to gain operating hours as soon as practicable on the 7HA.01 machine to demonstrate its successful performance. To achieve the in-service date of summer 2016, the Project will need to begin a 12-month replacement process by the summer of 2015. The replacement requires removal of the existing Unit 2 7H prior to installation of the 7HA.01 replacement.



Source: URS, 2014

0 4,000 8,000 Feet

SITE VICINITY

Turbine Replacement Project
Inland Empire Energy Center
Menifee, California

October 2014

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FIGURE 1-1

Although IEEC currently intends to adhere to this schedule, it is possible that unforeseen circumstances could delay the Project, or cause it to be abandoned altogether. Until such time as IEEC commences the Project, the existing CEC license would continue in effect, and the amendments requested herein would only become effective upon full implementation of the Project.

The proposed 7HA.01 combustion turbine (CT) would be functionally identical to the existing turbine. The turbine replacement would be a flange-to-flange installation. The existing plant layout, including stacks and emission control unit locations, would remain unchanged. The proposed modifications, including all laydown and parking areas, are all within the 46-acre project site (see Figure 1-2). The Project will not result in any additional disturbed areas beyond the site that were not previously evaluated in the record supporting adoption of the 2003 Commission approval and the 2005 IEEC Amendment.

This Petition describes the proposed Project, and analyzes the Project's consistency with applicable LORS and potential to cause any significant environmental impacts. As set forth below, the Project is consistent with applicable LORS, and would not cause any new significant environmental impacts.

In addition to this Petition, Applicant has also submitted to SCAQMD an application to revise the existing Title V Operating Permit to reflect the change in equipment, and to obtain a Permit to Construct the replacement turbine. Other than administrative changes to reflect the change in gas turbine, Applicant will not request changes to the emission limits or other conditions in the current Title V Operating Permit for the 7HA.01 replacement. Because the 7HA.01 turbine is functionally identical to the existing 7H turbine, with no increase in maximum rating or potential to emit (PTE) any air contaminant, the Project is exempt from certain nonattainment New Source Review (NSR) requirements per the exemption for replacements in SCAQMD Rule 1304(a)(1). This provision exempts the Project from performing modeling or providing offsets. The Project still has to demonstrate that the 7HA.01 turbine meets all Best Available Control Technology (BACT) requirements. Applicant has notified the U.S. Environmental Protection Agency (U.S. EPA) that the Project does not trigger Prevention of Significant Deterioration (PSD) review because baseline actual emissions (BAE) compared to projected actual emissions (PAE) do not exceed PSD significance levels.

1.1 AMENDMENT PROCESS

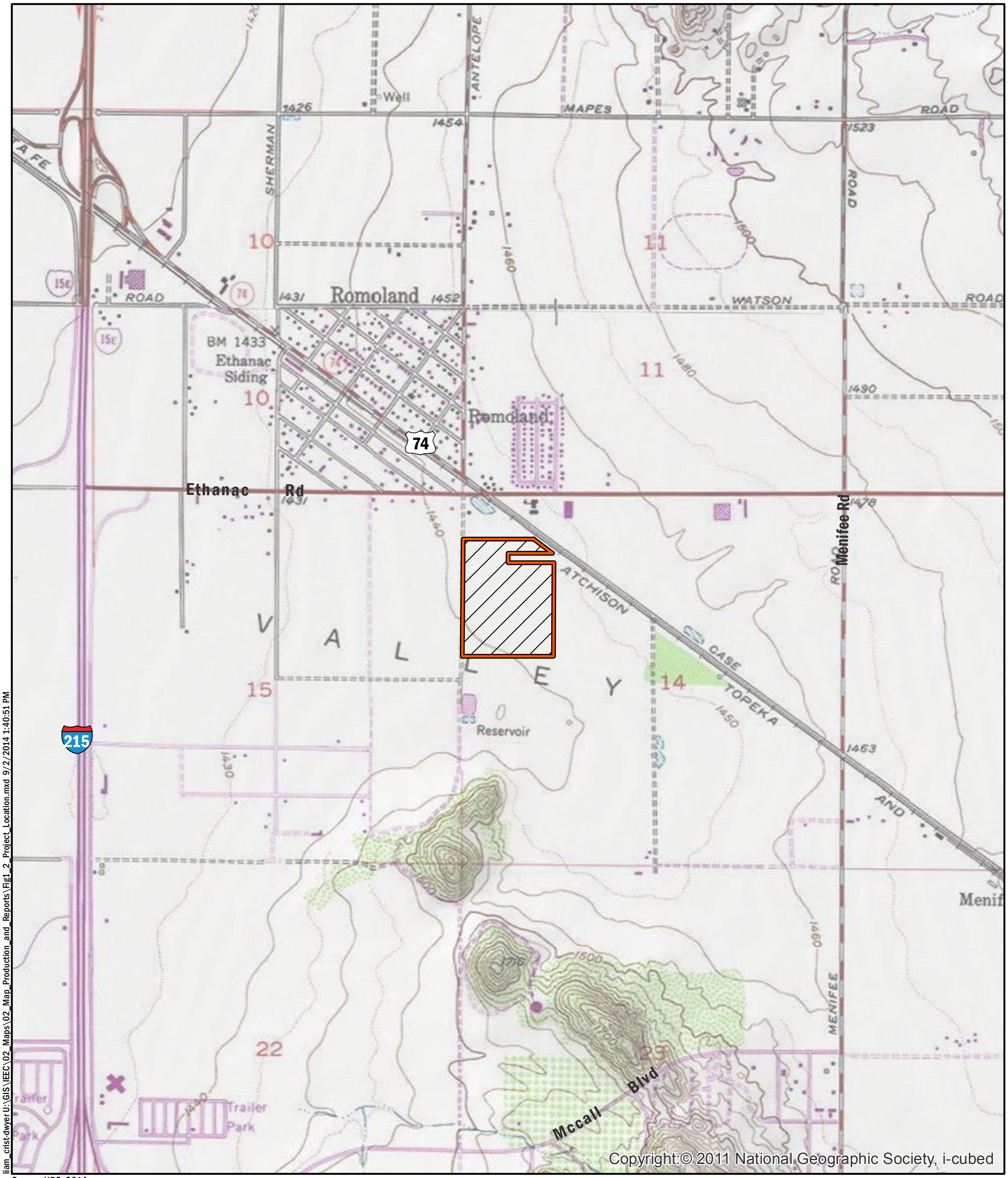
The CEC has the exclusive authority to certify the construction and operation of thermal electric power plants 50 MW or larger in California, such as the IEEC. The CEC certification is in lieu of any permit required by state, regional, or local agencies, and federal agencies to the extent permitted by federal law.[1] The CEC also has jurisdiction over petitions to amend its certification (such as this PTA), whereby the CEC assesses potential environmental impacts and compliance with applicable LORS.[2]

The CEC's siting regulations require staff to independently review the PTA. Staff conducts its environmental analysis in accordance with the California Environmental Quality Act (CEQA). The CEC's site certification and amendment program has been certified by the Resources Agency as a CEQA-equivalent process.[3] The CEC acts in the role of the CEQA lead agency.

Section 1769(a)(3) of the CEC's regulations authorizes the CEC's approval of the PTA if it can make the following findings:

- The findings specified in Section 1755(c) [whether all significant environmental impacts can be mitigated or avoided], and (d) [if all significant impacts cannot be avoided, overriding considerations justify approving the amendment], if applicable;

1 Pub. Resources Code Section 25500.
2 Pub. Resources Code Sections 25519, 25523(d).
3 Pub. Resources Code Section 21080.5; Cal. Code Regs., Title 14, Section 15251(k).



Source: URS, 2014

Project site

0 1,000 2,000 Feet

PROJECT LOCATION

Turbine Replacement Project
Inland Empire Energy Center
Menifee, California

October 2014

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FIGURE 1-2

- That the project would remain in compliance with all applicable LORS, subject to the provisions of Public Resources Code Section 25525;
- The change will be beneficial to the public, project owner, or intervenors; and
- There has been a substantial change in circumstances since the CEC certification justifying the change or that the change is based on information that was not available to the parties prior to CEC certification.

To facilitate staff's review, this PTA provides the information necessary to complete staff's CEQA analysis, determine compliance with applicable LORS, and make findings required by Section 1769. Applicant anticipates that staff can complete its analysis in a single Staff Assessment for consideration directly by the Commission at a regularly scheduled business meeting. Applicant does not anticipate that disputes would arise requiring the need for evidentiary hearings before the Siting Committee (Applicant does not believe the project requires a separate Committee).

1.2 INFORMATION REQUIRED BY 20 CCR 1769

20 CCR 1769 specifies that the petition must contain the following information:

(A) A complete description of the proposed modifications, including new language for any conditions that will be affected.

A complete description of the proposed modifications is provided in Section 2.0, below. A discussion of the Project's potential environmental impacts is provided in Section 3.0, and in the attached technical appendices.

Applicant is not proposing any significant changes to the Conditions of Certification included in the original IEEC approval, the 2005 IEEC Amendment and subsequent amendments (CEC, 2003b; CEC, 2005a; CEC, 2005b; CEC, 2005c; CEC, 2005d; CEC, 2007; CEC, 2010; CEC, 2012). Given the limited scope of the Project, only a subset of the existing conditions are applicable to the Project. The Conditions of Certification that apply to the Project are summarized in Appendix E. Applicant's proposed modifications to the Conditions of Certification are also provided in Appendix E.

(B) A discussion of the necessity for the proposed modifications.

The Project would allow the IEEC to take advantage of the most recent developments in gas turbine technology. The new 7HA.01 unit would provide the following benefits:

- Improved efficiency;
- Lower operation and maintenance costs; and
- Reduced water use from an air-cooled gas turbine.

Overall, the new turbine's operational improvements would better align and integrate IEEC with California's electric system as it increasingly relies on intermittent renewable resources, such as solar and wind facilities. The project also provides a unique opportunity for Applicant to install, test, and demonstrate this new technology.

(C) If the modification is based on information that was known by the petitioner during the certification proceeding, an explanation why the issue was not raised at that time.

The 7HA.01 turbine was not available prior to certification. Therefore, the proposed modifications could not have been raised at the time of the original certification.

(D) *If the modification is based on new information that changes or undermines the assumptions, rationale, findings, or other bases of the final decision, an explanation of why the change should be permitted.*

The turbine replacement does not materially change or undermine the assumptions, rationale, findings, or other bases of the Commission's approval of the IEEC. As shown in Section 3.0, the Project would not result in any new significant environmental impacts, and the IEEC would continue to comply with all applicable LORS.

(E) *An analysis of the impacts the modification may have on the environment and proposed measures to mitigate any significant adverse impacts.*

A detailed analysis of the potential environmental impacts of the Project and related mitigation measures is provided in Section 3.0, below. The Project would not result in any new significant environmental impacts, and no mitigation measures beyond those already included in the existing Conditions of Certification are required.

(F) *A discussion of the impact of the modifications on the facility's ability to comply with applicable laws, ordinances, regulations, and standards.*

Except as otherwise discussed in Section 3.0, the LORS analyses completed for the original certification and the 2005 IEEC Amendment continue to apply. Section 3.0 discusses compliance with LORS that may be affected by the Project. As shown below, the Project would comply with all applicable LORS.

(G) *A discussion of how the modification affects the public.*

As discussed in Section 3.0, the Project would not result in any significant environmental impact, and would be consistent with applicable LORS. As a result, the Project would not have a material adverse effect on the public.

(H) *A list of property owners potentially affected by the modification.*

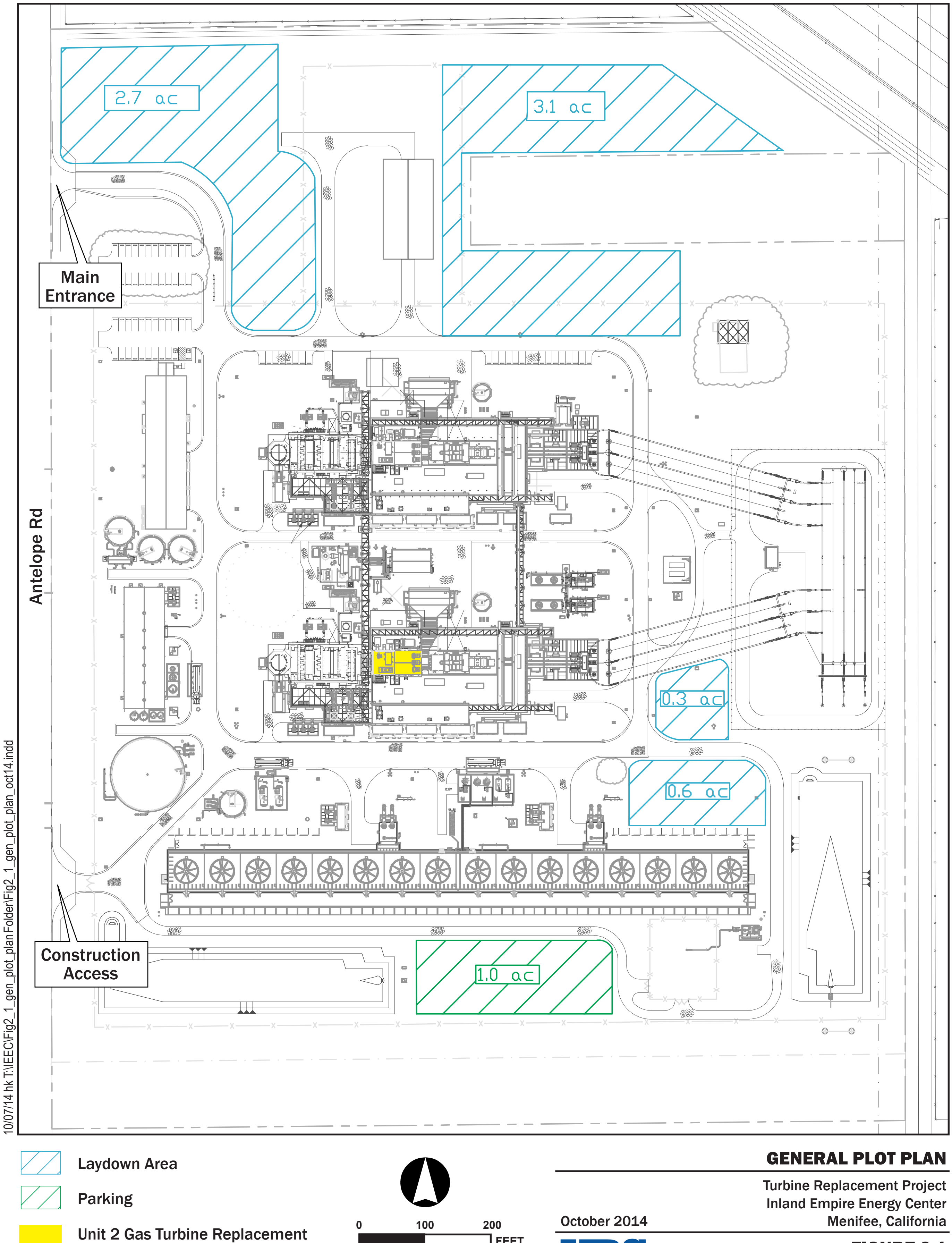
The Project would not have any material adverse effect on any property owners. The list of property owners within 1,000 feet of the IEEC is provided in Appendix A. The list has been newly compiled for this Petition to reflect data currently available in the public land records.

(I) *A discussion of the potential effect on nearby property owners, the public and the parties in the application proceedings.*

As discussed in Section 3.0, the Project would not result in any significant environmental impacts, and would be consistent with applicable LORS. The Project would not have a material adverse effect on nearby property owners or the public.

2.0 PROJECT DESCRIPTION

The Project would replace the existing Unit 2 7H turbine with a functionally identical replacement: the new GE 7HA.01 turbine. The 7HA.01 turbine has faster startup times with lower emissions; no increase in PTE of any criteria pollutant at steady-state; and is more efficient than the 7H. A comparison of the two turbines' operating parameters and steady-state emissions is shown in Table 2-1. The existing plant layout and balance of plant equipment, including stacks, heat recovery steam generator (HRSG) and associated emission control systems, and STG, will remain unchanged. The existing inlet air filtration, oxidation catalyst, and selective catalytic reduction systems will continue to provide emission controls. Figure 2-1 shows a general plot plan of the facility, with the small area affected by the Project highlighted in yellow.



GENERAL PLOT PLAN

Turbine Replacement Project
Inland Empire Energy Center
Menifee, California

October 2014

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FIGURE 2-1

Table 2-1
Inland Empire Energy Center
Comparison Between Existing 7H and Proposed 7HA.01 Gas Turbine

Parameter	Units	7H	7HA.01
Make and Model	—	GE S107H	TBD
Heat Consumption (HHV)	MMBtu/hr	2,598	2,576
Nameplate capacity of Unit 2	MW	405	405
Stack Height above ground surface	Feet	No Change	No Change
Exhaust temperature	°F	151	186
Exhaust flow rate	ACFM	1,360,935	1,376,317
Turbine Cooling	—	Steam-cooled	Air-cooled

Notes:

Exhaust parameters based on the cold temperature, baseload capacity case.

ACFM = actual cubic feet per minute
°F = degrees Fahrenheit
GE = General Electric Company
HHV = higher heating value
MMBtu/hr = million British thermal units per hour
MW = megawatts
TBD = to be determined

2.1 EQUIPMENT CHANGES

Only the turbine in Unit 2 would be replaced. Elements of the turbine replacement include the following:

- The new 7HA.01 gas turbine would replace the existing 7H gas turbine at Unit 2, as shown on Figure 2-1.
- Removal of the existing 7H gas turbine would include removal of the gas turbine compartment and foundation piers, and the 7H auxiliaries.
- Installation of the new 7HA.01 gas turbine would include: new modular gas turbine compartment, which includes auxiliaries; foundation piers; gas turbine controls; rapid-response terminal attemperators; and inlet bleed heat manifold and piping.
- The turbine replacement would be a flange-to-flange installation.
- The new gas turbine would be mounted on the existing concrete pedestal, elevated approximately 36 feet above grade.
- The existing plant layout, including stacks and emission control units, would remain unchanged.
- Table 2-1 identifies the characteristics of the new 7HA.01 gas turbine, and compares them to the existing 7H gas turbine.

2.2 REPLACEMENT ACTIVITIES

Replacement of the gas turbine is expected to take approximately 1 year, from the summer of 2015 to the summer of 2016. Testing and tuning is expected to take approximately 2 months out of the 12 months. Project completion is expected by Second Quarter 2016.

Project milestones are as follows:

- Begin Replacement Project – Second Quarter 2015
- Begin Startup and Testing – First Quarter 2016
- Project Completion – Second Quarter 2016

The onsite workforce profile is substantially less than the original build workforce profile, and is expected to reach its peak of approximately 100 individuals during month 8 of installation. There would be an average monthly workforce of approximately 80 craft people, supervisory, support, and installation management personnel on site during the replacement Project. Truck trips are expected to be an average of four delivery trucks and two heavy duty trucks per day. Assuming that approximately one-third of the workforce would carpool (1.5 persons per vehicle), the peak number of worker trips would be approximately 65 round trips per day, or about 50 on average. Because this is an existing operating site, heavy-haul, cranes, and installation equipment would be provided by onsite equipment and powered in a manner similar to a major outage.

Figure 2-1 shows the equipment laydown and parking areas within the 46-acre IEEC property. Most of the equipment laydown and parking areas are either paved or graveled. The northeastern area that will be used for laydown is tilled annually as part of ongoing operational best management practices. No new site preparation work, such as grading or excavating, is required for any of the laydown or parking areas.

Similar to delivery of the original gas turbines, the new gas turbine would be delivered by rail to the IEEC area and then trucked to the site. All heavy hauls will be completed in accordance with applicable requirements when the route is determined by the appropriate jurisdiction. Remaining materials and equipment would be delivered by truck. The main access for deliveries would be the IEEC's secondary entrance, located at the southwestern corner of the property.

2.3 OPERATIONS

IEEC would operate the facility with the new 7HA.01 turbine within the existing permitted envelope for emissions; therefore, no changes to the PTO conditions are expected.

Because the turbine would now be air cooled, steam cooling of the turbine and fuel moisturization would be removed. This results in a reduction of approximately 80 gallons per minute (gpm) of demineralized water consumption, or approximately 118 gpm of recycled water consumption. Currently, Unit 2 uses approximately 290 gpm of demineralized water. Therefore, the change to air cooling would reduce the amount of demineralized water used by approximately 27 percent, and the amount of recycled water used by approximately 4 percent.

The water treatment and water uses remain consistent with the previous design and license conditions. The plant's steam cycle would still be a closed cycle, with minimal makeup water required. Blow-down rates would not change. Cooling tower blow-down and evaporation remain unchanged, because output and cycles of concentration remain the same.

As currently licensed by the CEC, water supply would continue to be provided by Eastern Municipal Water District (EMWD), primarily from its Perris Valley Regional Water Reclamation Facility (RWRF), and supplemented from Moreno Valley RWRF and Temecula Valley RWRF.

The existing HRSG, steam turbine, pollution controls, and auxiliary equipment will not require significant modifications or changes to operational parameters. As shown in Table 2-2, the 7HA.01 turbine emissions in steady-state and startup are less than or equal to the emissions of the existing 7H turbine; therefore, no increase in permitted emissions will be necessary.

There are no anticipated changes in IEEC personnel for operations.

Table 2-2
Comparison of Turbine Emission Profiles

Operation	Turbine	NO_X	PM	CO	SO_2	VOC
Steady-State (lb/hr)	7HA.01	18.7	7.5	11.4	1.83	3.3
	7H	18.8	7.5	17.2	1.83	6.6
Cold Start (lb/event)	7HA.01	307	5.60	188	0.76	16
	7H	803	45	2000	10.98	48
Hot Start (lb/event)	7HA.01	59	3.10	144	0.33	13
	7H	408	7.5	800	1.83	16

Notes:

CO = carbon monoxide
lb/hr = pounds per hour
NO_X = nitrogen oxides
PM = particulate matter
SO_2 = sulfur dioxide
VOC = volatile organic compounds

3.0 ENVIRONMENTAL ANALYSIS

This environmental analysis is intended to support staff's environmental assessment of the Project. Under CEQA, the potential impacts are compared against the existing environmental setting, often called the "baseline." The baseline is typically considered the physical environmental conditions in the vicinity of the project at the time environmental analysis is commenced.[4] For an existing facility such as the IEEC, baseline conditions are not determined by maximum permitted levels, but rather by representative existing conditions at the time the environmental review is started.[5] Accordingly, the CEQA analysis compares the Project's impacts to the existing environmental conditions, which include the current operations of the IEEC.

As discussed in this section, the proposed turbine replacement would not result in any new significant environmental impacts. All impacts are expected to remain less than significant with implementation of Conditions of Certification set forth in the 2003 Commission decision and 2005 IEEC Amendment and subsequent amendments. As discussed, the IEEC would continue to comply with all applicable LORS after implementation of the Project.

3.1 AIR QUALITY

The 7HA.01 turbine has faster startup times with lower emissions, no increase in PTE of any criteria pollutant at steady-state, and is more efficient. The 7HA.01 turbine would use the existing HRSG, STG, emissions controls, continuous emission monitoring system, stack, and auxiliary equipment that are already in place, significantly minimizing the scope of the replacement effort involved. This section briefly describes the current background ambient air quality, and includes review of the Project emissions during the replacement, testing and tuning, and operations after the implementation of the Project. This section also includes detailed regulatory analyses of applicable, and potentially applicable rules and regulatory requirements organized by the SCAQMD rules, State of California regulatory programs, and federal regulations.

4 Cal. Code of Regs., tit. 14, § 15125(a).
5 *Communities for a Better Environment v. South Coast Air Quality Management Dist.*, 48 Cal. 4th 310, 316-17 (2010)

3.1.1 Background Ambient Air Quality

The IEEC is located in the South Coast Air Basin (SCAB). The SCAB is currently designated nonattainment with National Ambient Air Quality Standards (NAAQS) for particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) and ozone. The SCAB is also designated nonattainment for the California Ambient Air Quality Standards (CAAQS) for particulate matter less than 10 microns in diameter (PM_{10}), $PM_{2.5}$, and ozone. Existing background concentrations of criteria pollutants are shown in Table 3-1. Data are from the nearest monitoring site to the IEEC, Lake Elsinore, unless otherwise noted.

Table 3-1
Criteria Pollutant Background Concentrations

Pollutant	Averaging Period	Background[1] (μg/m^3)	CAAQS (μg/m^3)	NAAQS (μg/m^3)
CO[2]	1 hour	3,085	23,000	40,000
	8 hour	800	10,000	10,000
NO_2	1 hour CAAQS	94	339	–
	1 hour NAAQS	79	–	188
	Annual	19	57	100
PM_{10}[3]	24 hour	67	50	150
	Annual	34	20	–
$PM_{2.5}$	24 hour	41	–	35
	Annual	13	12	12
SO_2[4]	1 hour	21	655	196
	3 hour	N/A	–	1,300
	24 hour	13	105	365
	Annual	3	–	80

Notes:

1. Background is based on the highest concentration over the period from 2011-2013 at the Lake Elsinore monitoring station, unless otherwise noted.
2. CO only available at Lake Elsinore up to 2012; used 2010-2012 period.
3. PM_{10} data from the Perris monitoring station, as Lake Elsinore data was not complete.
4. SO_2 monitor data only available at the Riverside-Rubidoux station, approximately 25 miles northwest of IEEC.

N/A = not available

Data from California Air Resources Board (http://www.arb.ca.gov/adam/topfour/topfourdisplay.php) and U.S. EPA (http://www.epa.gov/airdata/ad_rep_mon.html).

CAAQS = California Ambient Air Quality Standards
CO = carbon monoxide
μg/m^3 = micrograms per cubic meter
NAAQS = National Ambient Air Quality Standards
NO_2 = nitrogen dioxide
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
SO_2 = sulfur dioxide

Since the 2005 IEEC Amendment (CEC, 2005a), air quality in the SCAB has improved, and there have been several changes in attainment status for various pollutants. These changes are shown in Table 3-2.

Table 3-2
South Coast Air Basin Attainment Status

Pollutant	Federal Attainment Status		State Attainment Status	
	2005	2014	2005	2014
Ozone	Nonattainment	Nonattainment	Nonattainment	Nonattainment
CO	Nonattainment	Maintenance	Attainment	Attainment
NO_2	Unclassified/ Attainment	Attainment	Attainment	Attainment
SO_2	Attainment	Attainment	Attainment	Attainment
PM_{10}	Nonattainment	Attainment	Nonattainment	Nonattainment
$PM_{2.5}$	Nonattainment	Nonattainment	Nonattainment	Nonattainment

Notes:

CO = carbon monoxide
NO_2 = nitrogen dioxide
SO_2 = sulfur dioxide
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter

Source: National Area Designations, U.S. EPA (http://www.epa.gov/airquality/greenbk/index.html)

3.1.2 Replacement Activity Emissions

Activities associated with the proposed turbine replacement Project could cause short-term emissions of criteria air pollutants. The primary source of nitrogen oxides (NO_X), carbon monoxide (CO), and sulfur oxides (SO_X) emissions is the operation of heavy equipment. The sources of particulate matter (PM_{10} and $PM_{2.5}$) emissions include activities such as foundation improvements, removal of the current Unit 2 7H gas turbine, and heavy equipment exhaust. Heavy equipment exhaust is also a source of diesel particulate matter.

The proposed turbine replacement Project does not require any soil-disturbing activities or paving operations. The primary sources for criteria air pollutants during installation are the operation of heavy equipment, delivery of equipment by rail and truck, and transportation of workers. There would only be minimal demolition activities that would create fugitive emissions, because the entire turbine compartment would be removed and replaced from flange to flange. The new turbine compartment would be coated/painted at the factory. Startup and testing tasks prior to routine operation of the plant after Project completion are discussed in the following subsection.

The replacement project will last approximately 12 months, of which 2 months are for gas turbine tuning and testing. Equipment laydown and parking areas would be within the boundaries of the 46-acre CEC-licensed site. Most of the equipment laydown, parking areas, and roads are either paved, graveled, or annually maintained (tilled). No new site ground disturbance or preparation work, such as grading or excavating, will be required.

The peak monthly workforce, and therefore the number of worker trips, would be considerably smaller than the workforce and trips for the original construction of the IEEC; construction activities that the Commission determined resulted in less-than-significant environmental impacts (CEC, 2003b). As described in the 2005 IEEC Amendment, the peak onsite construction workforce was estimated to be approximately 750, with an average monthly workforce of approximately 366 (IEEC, 2005). In comparison, the proposed turbine replacement Project would only require an estimated peak monthly workforce of approximately 100 workers, and average of approximately 80 workers, similar to an operational maintenance outage.

Major equipment delivery would be limited to the new 7HA.01 gas turbine, which would be delivered via rail and then trucked to the site. Deliveries of miscellaneous equipment also will be considerably less than deliveries during the original construction. For the 2005 IEEC Amendment, the analysis had assumed up to 553 peak daily round trips, of which 500 were for workers, 27 for deliveries, and 26 for heavy trucks. By contrast, peak daily round trips for the 7HA.01 turbine replacement project are estimated to be approximately 65 for workers, 4 for deliveries, and 2 for heavy trucks, similar to an operational maintenance outage.

In accordance with Air Quality Condition of Certification AQ-SC3, all diesel-fueled engines used will be fueled only with ultra-low sulfur diesel, containing no more than 15 parts per million sulfur. Furthermore, in accordance with the existing CEC license conditions, IEEC will implement emission reduction strategies during installation that would include the following:

- Limiting engine idling;
- Shutting down equipment when not in use;
- Conducting regular preventative maintenance to avoid engine problems;
- Use ultra-low sulfur and low aromatic fuel meeting California standards for motor vehicle diesel fuel; and
- Use low-emitting gas and diesel engines meeting state and federal emissions standards for diesel engines with a rating of 50 horsepower or higher.

The small greenhouse gas (GHG) emission increases from turbine replacement activities would not be significant for several reasons. First, the period of installation will be short-term, and the emissions will be intermittent during that period, not ongoing during the life of the Project. Additionally, implementation of control measures to address criteria pollutant emissions, such as limiting idling times, and requiring, as appropriate, equipment that meets the latest criteria pollutant emissions standards, would further minimize GHG emissions to the extent feasible. The use of newer equipment will increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of future California Air Resources Board (CARB) regulations to reduce GHG from construction vehicles and heavy equipment.

Due to the short duration of the replacement installation and the limited use of heavy equipment, emissions associated with the replacement activities are expected to be substantially less than what was analyzed and found to be less than significant in the 2005 IEEC Amendment. Accordingly, as with the 2005 IEEC Amendment, the Project will not result in any significant adverse impacts to air quality during the installation of the 7HA.01 gas turbine. Therefore, potential impacts associated with the replacement of the turbine will be less than significant.

3.1.3 Testing and Tuning Emissions

Because the 7H turbines at IEEC were the first installation of these units in the field, a "characterization program" was necessary for GE to be able to deploy these units in other locations. For this replacement project, the 7HA.01 turbine will undergo this preliminary full-speed, full-load testing at GE's extensive validation facility in Greenville, South Carolina. This will reduce the testing and tuning time at the Project site; therefore, the replacement Project emissions associated with testing and tuning will be less when compared to the previous turbine installation, as presented in Table 3-3.

Table 3-3
Inland Empire Energy Center
Testing and Tuning Emissions for 7H and 7HA.01 Turbines

Source	Total Fired Hours	NO_X Max Emission Rate lb/hr	CO Max Emission Rate lb/hr	VOC Max Emission Rate lb/hr	PM_{10} Max Emission Rate lb/hr	NO_X Total Tons	CO Total Tons	VOC Total Tons	PM_{10} Total Tons
2005 7H both units	509	N/A	N/A	N/A	N/A	43	14	1.1	3
2005 7H one unit	255	587	777	13	10	21	7	0.5	1.3
2014 7HA.01 one unit	247	169	412	13	7.5	11	6.7	0.45	0.9
Net Change	-8	-418	-365	0	-3	-10	-0.2	-0.1	-0.4

Notes:
1. In 2005, only one turbine was to be commissioned at a time; therefore, hourly emission rates for both units do not apply.

CO = carbon monoxide
lb/hr = pounds per hour
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
VOC = volatile organic compounds

Testing and tuning activities for the 7HA.01 will include the following steps:

- Gas turbine start-up
- Gas turbine sync and load
- HRSG operation on steam bypass (rapid response testing)
- Gas turbine loading up to base
- Dry low-NO_X Tuning
- Integrated tuning and performance test
- Operation tuning
- Performance tests
- Compliance testing
- Replacement project completed

For the 2005 IEEC Amendment, the CEC analyzed whether commissioning emissions would cause exceedances to applicable nitrogen dioxide (NO_2) or CO standards. PM_{10} and SO_X commissioning emissions were not analyzed because they were not higher than those occurring during normal startup and operation.[6] The state and federal standards for CO, both 1-hour and 8-hour, are currently the same as they were at the time of the 2005 IEEC Amendment. Therefore, with lower emissions compared to the 2005 IEEC Amendment, no significant impacts from CO emissions during the replacement project will occur.

Since the time of the 2005 IEEC Amendment, the CAAQS 1-hour NO_2 standard has been reduced from 470 micrograms per cubic meter ($\mu g/m^3$) in 2005, to a current value of 339 $\mu g/m^3$. This standard is a value not to be exceeded, and is compared to the maximum modeled impact plus a representative background concentration. The previously modeled emissions and maximum modeled impact have been used to estimate the maximum impact from the 7HA.01 replacement emissions of NO_X, which are significantly lower. As shown in Table 3-4, the estimated total impact is 168 $\mu g/m^3$, much less than the CAAQS of 339 $\mu g/m^3$. Because the installation of the gas turbine is a short-term event, emissions are not compared to the 1-hour NO_2 NAAQS, as it is a statistical standard based on a 3-year average (see Section 3.1.4.1.5 for additional discussion of the 1-hour NO_2 NAAQS standard). Therefore, as with the 2005 IEEC Amendment, no significant impact from NO_X emissions during testing and tuning will occur.

[6] 2005 IEEC Amendment, Staff Assessment, p. 11.

Table 3-4
Inland Empire Energy Center
Estimated NO_X Installation Impacts

Source	NO_X Maximum Hourly Emission Rate lb/hr	NO_2 1-Hour Modeled Maximum Impact µg/m³	NO_2 1-Hour Scaled Maximum Impact µg/m³	Background µg/m³	Total Impact µg/m³	CAAQS µg/m³
2005 7H (one unit)	587	257	—	169	426	470
2014 7HA.01	169	—	74	94	168	339

Notes:

1. 7H data from Tables 4 and 5 of the 2005 CEC Final Analysis.
2. Current background for comparison to the CAAQS is the maximum 1-hour NO_2 concentration at Lake Elsinore in 2011-2013 (http://www.arb.ca.gov/adam/topfour/topfour1.php). As indicated, background concentrations of NO_2 have decreased substantially since 2005.

CAAQS = California Ambient Air Quality Standards
CEC = California Energy Commission
lb/hr = pounds per hour
µg/m³ = micrograms per cubic meter
NO_X = nitrogen oxides
NO_2 = nitrogen dioxide

3.1.4 Operational Emissions and Regulatory Analysis

The Project's actual emissions during operation will depend on how the replacement Unit 2 is dispatched into the Southern California electricity market, and IEEC has considered a number of scenarios for this Project. As noted above, the Project operational emissions will be the same or less than the current Title V permitted emissions, and no changes to permitted emission rates or limits are proposed as part of the Project. Although approval of the replacement Project will not result in emissions in excess of the existing permitted emissions, a number of regulatory programs are applicable or potentially applicable. The methodology for comparing and calculating pre-Project and post-Project emissions varies depending on the particular requirements under consideration. Detailed emissions and regulatory analyses for potentially applicable local air district (SCAQMD), State of California, and federal requirements are included in the following subsections.

3.1.4.1 South Coast Air Quality Management District

The project will require a Permit to Construct pursuant to District Rule 201, which states that a person "shall not build, erect, install, alter or replace any equipment . . . the use of which may cause the issuance of air contaminants . . . without first obtaining written authorization for such construction from the Executive Officer." The Permit to Construct must be obtained prior to beginning physical installation of the replacement 7HA.01. In addition, IEEC currently holds a Title V Operating Permit that would be revised pursuant to SCAQMD Regulation XXX as part of the Project. Concurrent with the filing of this PTA, IEEC has filed the necessary applications with the SCAQMD.

3.1.4.2 SCAQMD Regulation 13 – Nonattainment New Source Review

Nonattainment NSR applies to new "major" sources, or "major modifications" at existing sources, for pollutants where the area is not in attainment with the NAAQS—such as the SCAB, where IEEC is located. NSR permitting generally requires: (1) the installation of BACT on the new or modified equipment; (2) the offsetting of project emissions, typically satisfied via the surrender of Emission Reduction Credits (ERCs); (3) modeling to demonstrate compliance with applicable air quality standards; and (4) opportunity for public and U.S. EPA review and comment on the permit issuance and/or revisions.

The PTE of the IEEC following the Project will not be greater than the existing PTE, and on a PTE-to-PTE basis, there will be no net increase in emissions. In fact, the IEEC PTE following the turbine replacement will be considerably lower than the existing IEEC PTE for certain pollutants due to the increased efficiency of the 7HA.01 turbine. However, SCAQMD permitting procedures evaluate a replacement unit as though it were a new unit. Therefore, the change in net emissions associated with the Project is calculated according to SCAQMD Rule 1306(b) for emission increases based on PTE; and SCAQMD Rule 1306(c) for emission decreases based on actual emissions over the most recent 24-month period of data available, as shown in Table 3-5. For this analysis, the period of July 2012 through June 2014 was used. Annual average emissions during this period are divided by the number of valid operational days for Unit 2 in that period to calculate actual pounds per day (lb/day). Detailed operational emission calculations are provided in Appendix B.

Table 3-5
Potential Emissions Minus Baseline Actual Emissions (Daily Basis)

Pollutant	NO_X	PM	CO	SO_2	VOC
Potential Emissions (lb/day)	741.8	180.0	453.1	43.3	91.2
Baseline Actual Emissions (lb/day)	103.6	63.3	24.2	15.3	38.7
Difference (lb/day)	638.2	116.7	428.9	28.0	52.5

Notes:

1. Potential emissions calculated per Rule 1306(b), based on one cold start per day and the remainder of the day at steady-state.
2. Baseline actual emissions calculated based on Rule 1306(c), using the actual emissions for Unit 2 over the last 24 months (July 2012 through June 2014). Annual emissions were divided by the number of valid operating days in that period for a daily average. Based on the number of operating days in each year, a usage factor of 0.5 was applied. Further details are presented in Appendix B.

CO = carbon monoxide
lb/day = pounds per day
NO_X = nitrogen oxides
PM = particulate matter
SO_2 = sulfur dioxide
VOC = volatile organic compounds

Because the 7HA.01 turbine is functionally identical to the existing 7H turbine, with no increase in maximum rating or PTE of any air contaminant, the Project is exempt from certain NSR requirements per the exemption for replacements in SCAQMD Rule 1304(a)(1). This provision exempts the Project from performing modeling or providing offsets. Prior to construction of the IEEC, worst-case air quality modeling, ambient air quality modeling impact assessment, and a complete mitigation package of offsets were part of the pre-construction licensing and permitting for the existing IEEC (IEEC, 2005; CEC, 2005a; CEC, 2005c; CEC, 2007).

As illustrated in the BACT analysis contained in Appendix C, the 7HA.01 turbine meets all BACT requirements. The proposed BACT for the Project is summarized in Table 3-6.

Table 3-6
Proposed BACT for Turbine Replacement Project

Pollutant	Technology	Proposed Emission Limit
NO_X	DLN burners and SCR	2.0 ppmvd NO_X at 15 percent O_2, 1-hour average
CO	GCP, oxidation catalyst	2.0 ppmvd CO at 15 percent O_2, 1-hour average
PM	GCP, pipeline quality natural gas	11 lb/hr or 0.01 gr/scf natural gas
$PM_{10}/PM_{2.5}$	GCP, pipeline quality natural gas	7.5 lb/hr
SO_X	Pipeline quality natural gas	0.9 lb/MWh ≤ 0.25 grain $H2_S$/100 scf in natural gas
VOC	Oxidation catalyst	1.0 ppmvd at 15 percent O_2, 1-hour average
NH_3	SCR	5 ppmvd NH_3 slip, 3-hour average
All pollutants during Startup/ Shutdown	GE “rapid response” technology, limit total startup and shutdown emissions, apply emission controls as much as feasible during the startup and shutdown events.	Daily startup and shutdown time shall not exceed 4 hours per turbine hot start, or 6 hours per day per turbine for a cold startup; monthly startup and shutdown time shall not exceed 31 hours per unit.

Notes:

BACT = Best Available Control Technology
CO = carbon monoxide
DLN = dry low-NO_X
GCP = good combustion practice
GE = General Electric Company
gr/scf = grains per standard cubic foot
H_2S = hydrogen sulfide
lb/hr = pound per hour
lb/MWh = pound per megawatt-hour
NH_3 = ammonia
NO_X = oxides of nitrogen
O_2 = oxygen
PM = particulate matter
PM_{10} = particulate matter less than 10 microns in aerodynamic diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in aerodynamic diameter
ppmvd = parts per million by volume, dry basis
scf = standard cubic foot
SCR = selective catalytic reduction
SO_X = sulfur oxides
VOC = volatile organic compound

3.1.4.2.1 SCAQMD Rule 1303, Visibility Analysis

District Rule 1303(b)(5)(C) requires a modeling analysis for plume visibility if the net emission increase from the new or modified source exceeds 15 tons per year (tpy) of PM_{10} or 40 tpy of NO_X; and the location of the source, relative to the closest boundary of a specified federal Class I area, is within the distances in Table C-1. The Rule 1304(a)(1) exemption for “functionally identical source” replacements does not apply to this modeling requirement. Because IEEC is further than the prescribed distances from specified federal Class I areas in Table C-1, Rule 1303(b)(5)(C), plume visibility modeling is not required. Distances to the Class I areas are shown in Table 3-7.

Table 3-7
Distance to Nearby Class I Areas

Federal Class I Area	Threshold Distance in Table C-1 (kilometers)	Distance from IEEC (kilometers)
Agua Tibia	28	34
Cucamonga	28	65
Joshua Tree	29	71
San Gabriel	29	86
San Gorgonio	32	46
San Jacinto	28	43

3.1.4.2.2 SCAQMD Rule 1325, $PM_{2.5}$ NSR

Rule 1325 regulates sources under the Federal NSR Program for $PM_{2.5}$. The Rule applies to facilities that are a major source of $PM_{2.5}$, and requires a demonstration that the Lowest Achievable Emission Rate for the new source or modification will be used; offsets for emission increases will be provided; and an alternatives analysis will be conducted. The threshold for a Major Polluting Facility is 100 tpy (Rule 1325[b][5]).

The IEEC facility-wide PTE of $PM_{2.5}$ is less than the 100-tpy threshold; therefore, this rule does not apply. Emissions by source are provided in Table 3-8, with more detailed calculations shown in Appendix B.

Table 3-8
Inland Empire Energy Center
IEEC Potential to Emit $PM_{2.5}$

Source	Potential to Emit (tpy)	
	PM_{10}	$PM_{2.5}$
Unit 1[1]	33.5	33.5
Unit 2[1]	33.5	33.5
Aux boiler[1]	1.3	1.3
Cooling towers[2,4]	15.4	0.02
Emergency Generator Engines[3]	0.0	0.0
Firewater Pump Engine	0.0	0.0
Total (tpy)	**83.7**	**68.3**

Notes:

1. Turbines and Aux Boiler – PM_{10} PTE based on permit limits
2. Cooling tower emissions based on 8,760 hours/year
3. Emergency engines and firewater pump emissions based on 50 hours/year
4. $PM_{2.5}$ from cooling towers is assumed to be 0.16 percent of PM, based on SCAQMD “Guidelines for Calculating Emissions from Cooling Towers” and “Calculating Realistic PM_{10} Emissions from Cooling Towers,” Joel Reisman and Gordon Frisbie, Abstract No. 216

IEEC = Inland Empire Energy Center
PM = particulate matter
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
PTE = potential to emit
SCAQMD = South Coast Air Quality Management District
tpy = tons per year

3.1.4.2.3 SCAQMD Rule 1714, GHG PSD

District Rule 1714 governs PSD analysis for GHGs. Subpart (b), Applicability, states that the rule applies to "any source and the owner or operator of any source subject to any GHG requirements under 40 Code of Federal Regulations (CFR) Part 52.21 as incorporated into this rule." In other words, SCAQMD Rule 1714 requires BACT for GHGs only for sources that trigger the aforementioned federal requirements.

In the case of *Utility Air Regulatory Group v. EPA*, the U.S. Supreme Court held that emissions of GHGs alone cannot trigger PSD applicability, but that once sources trigger PSD review due to their criteria pollutant emissions, such sources must limit emissions of GHGs through BACT.[7] As discussed in Section 3.1.4.3, the turbine replacement's criteria pollutant emissions do not exceed the significance levels set forth in 40 CFR Section 52.21(b)(23); therefore, the Project is not subject to PSD review for criteria pollutant emissions under the federal regulations. Because, under federal regulations, the Project does not trigger PSD review on the basis of its criteria pollutant emission increases, GHG BACT analysis is not required for this Project under District Rule 1714.

3.1.4.2.4 1-Hour NO_2 NAAQS Compliance

As indicated in Section 3.1.4.1.1, the Project is exempt from the requirement to conduct modeling to demonstrate compliance with ambient air quality standards pursuant to SCAQMD Rule 1304(a)(1).

Nonetheless, for informational purposes, Project emissions are compared to the NO_2 standard adopted since the initial certification of the IEEC, based on the analysis used in the 2005 IEEC Amendment. At the time of the 2005 IEEC Amendment the only 1-hour NO_2 standard in effect was the CAAQS of 470 $\mu g/m^3$. This value was not to be exceeded and was compared against the highest modeled concentration plus a representative background concentration.

Since that time a federal standard has been promulgated; the NAAQS is a statistical standard, and attainment is demonstrated by the 3-year average of the annual 98th percentile of daily maximum 1-hour concentrations at each receptor. This is the modeled design value. The representative background concentration is also calculated in the same manner and is referred to as the monitored design value. The sum of the modeled design value and the monitored design value must not exceed the NAAQS of 188 $\mu g/m^3$.

Because modeling previously performed for the IEEC only needed to show that the maximum impact was less than the CAAQS, the level of detail and amount of data necessary to make an accurate comparison to the new statistical NAAQS are not available. In the absence of such data, the maximum modeled impacts are used here, with the understanding that these values overestimate the actual impacts that would be compared to the NAAQS of 188 $\mu g/m^3$.

Two sets of modeling were performed in the 2005 proceedings: one by the Applicant (IEEC, 2005), and one by CEC Staff (CEC, 2005a). The Applicant's modeling used meteorological data from Riverside in 1981, according to SCAQMD requirements at the time, and ozone data from the Perris monitoring site in 1999. To account for the limiting effect of ozone concentrations on NO_2 formation from NO_X, the ozone limiting method was used. To be physically realistic, the meteorology and ozone data should be from the same site and data period. For this reason, Staff conducted its own analysis using meteorological and ozone data from March Air Force Base for the years 1997-2001. To reduce any uncertainty due to differing meteorology and ozone data periods, results from the Staff analysis are used here.

Importantly, the replacement turbine would use the same physical stack as the existing CT; exhaust temperatures are higher than those modeled previously; and in the worst-case condition (cold ambient

[7] 134 S. Ct. 2427, 573 U.S. ___ (2014) (Docket No. 12-1146).

temperature, baseload capacity) the exhaust velocity is also higher. Therefore, all stack parameters are either the same (e.g., location, height, diameter) or more favorable for dispersion (e.g., temperature and exit velocity). This similarity of stack parameters enables the comparison of previous model results to the proposed Project. In fact, estimates of the Project's impacts are likely overestimated, because they do not account for the more favorable stack parameters associated with the new 7HA.01 turbine.

The model results presented in the 2005 CEC Staff Analysis (CEC, 2005a) are based on the worst-case emission rate for each averaging period, accounting for all sources at the facility. For 1-hour NO_2, the worst-case emissions represented both gas turbines in startup mode, the auxiliary boiler in operation, and one emergency generator being tested (CEC, 2005a, Table 6). The maximum modeled 1-hour NO_2 impact was 267.5 µg/m^3.

Worst-case 1-hour NO_2 emissions as a result of the Project include the new 7HA.01 turbine in cold startup mode for 45-minutes and 15 minutes of normal operations; the existing Unit 1 turbine in normal operations; and the auxiliary boiler. The facility is only able to start one turbine at a time; therefore, only the new turbine is assumed to be in startup mode, and Unit 1 is assumed to be operating at a steady state. For comparison to the statistical form of the 1-hour NO_2 standard, the emergency generator emissions are not included in this emission estimate; per U.S. EPA guidance (U.S. EPA, 2011), these intermittent sources should not be included in comparison to the statistical standards. Based on the previously modeled maximum impact from the facility and scaling to the Project emission rate, the Project has an estimated maximum impact of 182.3 µg/m^3. This impact includes worst-case emissions and a representative background 1-hour NO_2 concentration, and is less than the NAAQS of 188 µg/m^3. This analysis is detailed in Table 3-9.

Table 3-9
Inland Empire Energy Center Scaled Comparison of 1-hour NO_2 Emissions to NAAQS

Reference	Source(s)	NO_X Maximum Hourly Emission Rate (lb/hr)	NO_2 1-Hour Modeled Maximum Impact (µg/m^3)	NO_2 1-Hour Scaled Maximum Impact (µg/m^3)	Background 1-Hour NO_2 (µg/m^3)	Total Impact (µg/m^3)
2005 CEC Staff Analysis	Both turbines in startup, aux boiler, one generator	859.0	267.5	—	—	—
2014 Petition to Amend	One turbine with a cold startup, one turbine in normal operations, auxiliary boiler	331.8	—	103.3	79.0	182.3

Notes:

CEC = California Energy Commission
lb/hr = pounds per hour
µg/m^3 = micrograms per cubic meter
NAAQS = National Ambient Air Quality Standards
NO_X = nitrogen oxides
NO_2 = nitrogen dioxide

It should be reiterated that the modeled impacts being discussed are the maximum concentration modeled over 5 years of meteorological data. This is an overestimate of what the modeled design value would be, if the data were available to calculate it, because that statistical value (3-year average of the annual 98th percentile of daily maximum 1-hour concentrations at each receptor) would be less than the maximum. For example, while the maximum 1-hour NO_2 concentration monitored at Lake Elsinore currently is 94 µg/m^3, the monitored design value for comparison to the standard is 79 µg/m^3. Therefore, if the less-conservative 3-year average approach were applied to the results shown in Table 3-9, the estimated impact would be even less.

3.1.4.3 State of California, CEQA and GHG

3.1.4.3.1 California Environmental Quality Act

To evaluate the Project's potential air quality impacts under CEQA, the IEEC's PTE following the turbine replacement is compared to baseline emissions representative of existing conditions. Baseline emissions have been calculated as the average annual emissions over the most recent 24-month period, which are representative of recent conditions at the IEEC and consistent with SCAQMD methodology. Table 3-10 shows the net increase in emissions associated with the Project, as demonstrated by subtracting baseline emissions from the Project's PTE.

Table 3-10
Inland Empire Energy Center
Potential Emissions Minus Baseline Actual Emissions (Annual Basis)

Pollutant	NO_X	PM	CO	SO_2	VOC
PTE – Annual permit limit (tpy) [1]	79.5	33.5	58.4	8.2	22.6
Baseline actual emissions (tpy) [2]	15.5	9.4	3.6	2.3	5.8
Difference (tpy)	64.0	24.1	54.8	5.9	16.8

Notes:

1. PTE is equal to the annual permit limit, based on annual RTCs for NO_X (permit condition I296.1); all other pollutants, annual permit limit based on monthly SCAQMD permit limit times 12 months/year (permit condition A63.1).
2. Baseline actual emissions are the average of the last 2 years of available data (July 2012 - June 2014).

CO = carbon monoxide
NO_X = nitrogen oxides
PM = particulate matter
PTE = potential to emit
RTC = RECLAIM Trading Credit
SCAQMD = South Coast Air Quality Management District
SO_2 = sulfur dioxide
tpy = tons per year
VOC = volatile organic compounds

As discussed above, this determination of baseline emissions for CEQA purposes is consistent with the California Supreme Court decision in *Communities for a Better Environment v. South Coast Air Quality Management Dist*., 48 Cal. 4th 310, 316-17 (2010), where the Court rejected using maximum permitted emissions as the baseline condition because "the baseline for CEQA analysis must be the 'existing physical conditions in the affected area,' that is, the 'real conditions on the ground,' rather than the level of development or activity that could or should have been present according to a plan or regulation."[8] The Court recognized that a lead agency has discretion to select a proper baseline as long as it is based on representative conditions.[9] Here, determining baseline emissions based on the average annual emissions over the most recent 24-month period is representative of recent conditions at the time the environmental analysis is commenced.[10] These calculations are shown in Table 3-10. Detailed calculations of operational emissions are included in Appendix B.

Note that the PTE of the IEEC following the turbine replacement will not be greater than the current PTE of the IEEC, and that the plant could emit at the full PTE as it exists today under its existing permits. The only reason a net emission increase is indicated for purposes of CEQA is that CEQA requires a comparison of the PTE following the turbine replacement to BAE prior to the turbine replacement, and the IEEC has not historically operated at its full PTE.

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[8] *Id*. at 321 (internal citations omitted).
[9] *Id*. at 328.
[10] *See id*. at 327-328 (a lead agency may select the baseline based on an average of recent conditions); Cal. Code Regs., tit. 14, Section 15125(a).

For the 2005 IEEC Amendment, the CEC determined that operational emissions may cause potentially significant air quality impacts by emitting PM_{10} and precursors to PM_{10}, $PM_{2.5}$ and ozone (CEC, 2005a). Staff determined that the emissions associated with the 2005 IEEC Amendment could be fully offset using the same mitigation strategy as the original 2003 Commission decision, and that no new mitigation was required. Specifically, Condition of Certification AQ-SC9 required IEEC to provide adequate RECLAIM Trading Credits (RTCs) for NO_X emissions under the SCAQMD's RECLAIM program: 822 lb/day of ERCs for CO emissions; 307 lb/day of ERCs for volatile organic compounds emissions; 91 lb/day of ERCs from the SCAQMD Priority Reserve program for SO_X emissions; and 379 lb/day of ERCs from the SCAQMD Priority Reserve program for PM_{10} emissions. Based on IEEC's design features and the offset mitigation imposed by Condition of Certification AQ-SC9, staff concluded the IEEC would comply with applicable LORS and would not cause a significant air quality impact under CEQA. The Commission approved the 2005 IEEC Amendment by adopting staff's conclusions and recommendations (CEC, 2005c; CEC, 2007).

Although IEEC is permitted as a base-load facility, historic demand has caused it to operate at a lower capacity factor. As a result, the offsets required by AQ-SC9, which were based on the IEEC's full PTE, have substantially over-mitigated IEEC's actual historical emissions. In other words, the offsets required by the 2005 IEEC Amendment have substantially exceeded the mitigation needed to cover IEEC's actual emissions to date.

Because the PTE of the IEEC following the turbine replacement will not be greater than the existing PTE of the IEEC, and because the IEEC has already offset its full PTE, all emissions that could occur after the turbine replacement have been fully mitigated by the offset mitigation adopted in the original certification and amendments. The combination of RTCs, ERCs and Priority Reserve credits required by AQ-SC9 provide more than sufficient mitigation to offset all of the IEEC's emissions following the turbine replacement, because the PTE of the IEEC will not exceed the existing IEEC PTE in all cases. Moreover, as has historically been the case, it is highly unlikely that the IEEC would ever emit at its maximum PTE due to market conditions. As a result, the offset mitigation that has been provided is likely to exceed actual IEEC emissions following replacement of the turbine. Because the maximum possible emissions will be fully mitigated, the Project will not cause a significant air quality impact under CEQA.

3.1.4.3.2 Greenhouse Gas Emissions and Regulation

This section analyzes the GHG emissions associated with the Project for purposes of CEQA, the California Senate Bill (SB) 1368 emissions performance standard, and the proposed federal new source performance standards (NSPS) for fossil-fuel-fired electrical generating units.

SB 1368 limits long-term financial commitments in baseload generation by the state's utilities to power plants that meet an emission performance standard (EPS), jointly established by the CEC and the California Public Utilities Commission (CPUC).[11] Specifically, the SB 1368 EPS applies to electricity from new power plants, new investments in existing power plants, and new or renewed contracts with terms of 5 years or more where the power plant is intended and designed to operate as a baseload power plant ("covered procurements"). Accordingly, if a power plant intends to sell electricity to a California utility under a long-term contract (5 years or more), then the utility must demonstrate that the power plant complies with the EPS. The EPS of 1,100 pounds per megawatt-hour (lb/MWh) of carbon dioxide (CO_2) is based on net power generation. The CEC is tasked with implementing the SB 1368 EPS for publicly owned utilities (POU), and the CPUC implements the EPS for investor-owned utilities (IOU). The IEEC is a merchant power plant without a long-term contract with a POU or IOU; accordingly, SB 1368 does not currently apply. Regardless, IEEC as modified would meet the SB 1368 EPS, if it applied.

On January 8, 2014, the U.S. EPA proposed the first Clean Air Act NSPS for emissions of CO_2 from new fossil-fuel–fired electrical generating units. U.S. EPA is proposing that natural-gas–fired stationary CTs

[11] Public Utilities Code Section 8340 et seq.

with a heat input rating greater than 850 million British thermal units per hour meet an output-based standard of 1,000 lb/MWh of CO_2 based on gross generation. The public comment phase was closed as of May 9, 2014, and the rule is projected to be finalized in January 2015.

GHG assessment is by its very nature a cumulative impact assessment. The emission of GHGs by a single project into the atmosphere is not itself necessarily an adverse environmental effect. Rather, it is the increased accumulation of GHG from more than one project and many sources in the atmosphere that may result in global climate change. According to the California Air Pollution Control Officers Association, "GHG impacts are exclusively cumulative impacts; there are no non-cumulative GHG emission impacts from a climate change perspective" (CAPCOA, 2008). It is global GHG emissions in their aggregate that contribute to climate change, not any single source of GHG emissions alone. The CEQA Guidelines clarify that the effects of GHG emissions are cumulative and should be analyzed in the context of CEQA's requirements for cumulative impact analysis.[12] The administrative record of the promulgation of the GHG emissions amendments to the CEQA Guidelines also make clear "that the effects of GHG emissions are cumulative, and should be analyzed in the context of CEQA's requirements for cumulative impact analysis" (Bryant, 2009).

The CEQA Guidelines identify three factors that should be considered in the evaluation of the significance of GHG emissions: (1) the extent to which a project may increase or reduce GHG emissions as compared to the existing environmental setting; (2) whether the project emissions exceed a threshold of significance that the lead agency determines applies to the project; and (3) the extent to which the project complies with regulations or requirements adopted to implement a statewide, regional, or local plan for the reduction or mitigation of GHG emissions (Bryant, 2009).

Following replacement of the turbine, the IEEC would emit GHGs, and therefore, it is appropriate to analyze its potential cumulative impact in the context of its effect on the electricity system, resulting GHG emissions from the system, and existing GHG regulatory requirements and GHG energy policies. The unique way power plants operate in an integrated system means that their operational GHG emissions should be assessed on a system-wide basis rather than on a stand-alone basis. From a policy and regulatory standpoint, the GHG emissions from a power plant's operation should be assessed in the context of the state's GHG laws and policies, such as Assembly Bill (AB) 32. The IEEC's operation would be consistent with the state's GHG policies and would help achieve the state's GHG goals, by: (1) causing a decrease in overall electricity system GHG emissions; and (2) fostering the addition of renewable generation into the system, which will further reduce system GHG emissions. Further discussion is provided below.

Gas-fired power plants currently play a vital role in advancing the state's climate and energy goals by displacing less-efficient generation resources and facilitating the integration of renewables into the system. In the Avenal Decision (CEC, 2009), the Energy Commission established a three-part test to aid in its analysis of a proposed gas-fired plant's ability to advance California's goals and policies. Under that test, gas-fired plants must:

1. Not increase the overall system heat rate for natural gas plants;
2. Not interfere with generation from existing renewable facilities, nor with the integration of new renewable generation; and
3. Reduce system-wide GHG emissions and support the goals and policies of AB 32.

IEEC's required compliance with the California Cap-and-Trade Program is an additional basis for finding that IEEC's GHG emissions will not cause a significant environmental impact. Per CEQA Guidelines Section 15064(h)(3), a project's incremental contribution to a cumulative impact can be found not cumulatively considerable if the project will comply with an approved plan or mitigation program that provides specific requirements that will avoid or substantially lessen the cumulative problem within the

[12] *See generally* 14 CCR Section 15130(f).

geographic area of the project. To qualify as adequate mitigation, such a plan or program must be specified in law or adopted by the public agency with jurisdiction over the affected resources through a public review process to implement, interpret, or make specific the law enforced or administered by the public agency. Examples of such programs include a "water quality control plan, air quality attainment or maintenance plan, integrated waste management plan, habitat conservation plan, natural community conservation plan, [and] **plans or regulations for the reduction of greenhouse gas emissions**." Put another way, CEQA Guidelines Section 15064(h)(3) allows a lead agency to make a finding of non-significance for GHG emissions if a project complies with the California Cap-and-Trade Program.[13]

The California Cap-and-Trade Program[14] is designed to reduce GHG emissions from major sources (deemed "covered entities") by setting a firm cap on statewide GHG emissions and employing market mechanisms to achieve AB 32's emission-reduction mandate of returning to 1990 levels of emissions by 2020. The statewide cap for GHG emissions from the capped sectors[15] (e.g., electricity generation, petroleum refining, and cement production) commenced in 2013 and will decline over time, achieving GHG emission reductions throughout the Program's duration. The Cap-and-Trade Program covers the GHG emissions associated with electricity consumed in California, whether generated in-state or imported.[16] Each covered entity with a compliance obligation is required to surrender "compliance instruments"[17] for each metric tonnes of carbon dioxide equivalents (CO_2e) of GHG they emit. Covered entities are allocated free allowances in whole or part if eligible (IEEC is not so eligible), buy allowances at auction, purchase allowances from others, or purchase offset credits. The Cap-and-Trade Program is scientifically linked under California's regulatory framework to ultimate stabilization of the climate. This linkage further demonstrates how compliance with the Cap-and-Trade Program supports the conclusion that IEEC's GHG emissions are not a significant impact on the environment.

One agency that is taking this approach is the San Joaquin Valley Air Pollution Control District (SJVAPCD), which recently adopted a policy to provide guidance to SJVAPCD staff on how to determine significance of GHG emissions from projects subject to the Cap-and-Trade Program, or occurring at entities subject to the Cap-and-Trade Program (SJVAPCD, 2014). The SJVAPCD "has determined that GHG emissions increases that are covered under CARB's Cap-and-Trade regulation cannot constitute significant increases under CEQA…." (SJVAPCD, 2014). Other pertinent statements in the SJVAPCD policy are as follows:

> Consistent with [14] CCR Section 15064(h)(3), the District finds that compliance with CARB's Cap-and-Trade regulation would avoid or substantially lessen the impact of project-specific GHG emissions on global climate change. … The District therefore concludes that GHG emissions increases subject to CARB's Cap-and-Trade regulation would have a less than significant individual and cumulative impact on global climate change (SJVAPCD, 2014).

In short, the SJVAPCD pragmatically has modified its existing CEQA significance threshold for GHG emissions to acknowledge the progress being made by the state in regulating and reducing such emissions.

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[13] Per CEQA Guidelines Section 15064(h)(3), a project's incremental contribution to a cumulative impact can be found not cumulatively considerable if the project will comply with an approved plan or mitigation program that provides specific requirements that will avoid or substantially lessen the cumulative problem in the geographic area of the project. To qualify as adequate mitigation, such a plan or program must be specified in law or adopted by the public agency with jurisdiction over the affected resources through a public review process to implement, interpret, or make specific the law enforced or administered by the public agency. Examples of such programs include a "water quality control plan, air quality attainment or maintenance plan, integrated waste management plan, habitat conservation plan, natural community conservation plan, [and] **plans or regulations for the reduction of greenhouse gas emissions**." (Emphasis added.)

[14] 17 CCR §§ 95800 to 96023.

[15] *See generally* 17 CCR §§ 95811, 95812.

[16] 17 CCR Section 95811(b).

[17] Compliance instruments are permits to emit, the majority of which will be "allowances," but entities also are allowed to use CARB-approved offset credits to meet up to 8 percent of their compliance obligations.

Because the replacement 7HA.01 turbine is more efficient than the existing 7H turbine, the IEEC PTE for GHG will be less after the turbine replacement Project. However, to satisfy CEQA requirements, the Applicant has analyzed future emissions to existing baseline emissions. The annual GHG emissions from IEEC following replacement of the turbine were calculated for the two turbines, an auxiliary boiler, fire pump engine, and two emergency generators, and are presented in Table 3-11. Emissions were calculated for each of the two proposed operating scenarios presented in the PSD applicability analysis (baseload scenario and cycling scenario). Net emissions are greater from the baseload scenario, representing the worst case emissions. Calculation details are presented in Appendix D.

Table 3-11
Annual CO_2e Emissions from the IEEC

CEQA GHG Analysis	Metric tons/year (CO_2e)					
	Unit 1	Unit 2	Auxiliary Boiler	Emergency Generators	Firewater Pump	Facility Total
Project Emissions[1,2]	522,774	1,114,759	520	105	11	1,638,168
Baseline Emissions[3]	522,774	440,782	520	105	11	964,192
Net Emissions	0	673,977	0	0	0	673,977

Notes:

1. Project emissions for Unit 2 are based on the proposed baseload operational scenario, which has higher net emissions than the cycling operational scenario.
2. Project emissions for Unit 1, Aux Boiler, emergency generators and firewater pump are equal to baseline, because they will not be impacted by the project.
3. Baseline emissions are based on the average of CO_2e emissions reported to the California Air Resources Board in 2012 and 2013. Because the emergency generators and firewater pump are exempt from this reporting, emissions are calculated based on their potential to emit, assuming 50 hours/year of testing each.

CEQA = California Environmental Quality Act
CO_2e = carbon dioxide equivalents
GHG = greenhouse gas
IEEC = Inland Empire Energy Center

Emissions of CO_2, methane (CH_4), and nitrous oxide (N_2O) from combustion of natural gas in the turbines and auxiliary boiler, and from diesel combustion in the emergency generators and firewater pump, were estimated using emission factors from Table C-1 and C-2 of 40 CFR 98 Subpart C.

GHG emissions are reported as CO_2e, which is defined as the sum of the mass emissions of each individual GHG multiplied by its global warming potential (GWP). GWP is a relative measure of how much heat a GHG compound traps in the atmosphere, compared to a similar mass of CO_2. U.S. EPA defines GWP for CO_2 as 1; 25 for CH_4; and 298 for N_2O (Table A-1, 40 CFR Part 98, Subpart A).

The SB 1368 emission calculations include the annual CO_2 emissions from each fuel used in any plant component directly involved in electricity production. This includes the CTG/HRSGs and the auxiliary boiler. The SB 1368 emission calculations do not include sulfur hexafluoride from the circuit breakers or emissions associated with the emergency generator, fire pump, and operations and maintenance vehicles.

The gross and net electricity production and GHG emissions were calculated based on both of the potential operating profiles presented in the PSD applicability analysis, a baseload scenario and a cycling scenario. In this analysis, the cycling scenario is more conservative (produces slightly higher emissions per megawatt-hour estimates) and is presented in Table 3-12.

Based on the analysis set forth above, the Project will not result in a significant environmental impact as a result of GHG emissions. Furthermore, as shown in Table 3-12, the IEEC's GHG emissions will be below both SB 1368's threshold requirement of the 1,100 lb/MWh of CO_2, and the proposed NSPS of 1,000 lb/MWh of CO_2. GHG emissions and calculations associated with the operation of IEEC are included in Appendix D, Greenhouse Gas Emissions.

Table 3-12
Inland Empire Energy Center
Greenhouse Gas Efficiency

Parameter	Unit 1 (7H)	Unit 2 (7HA.01)	Aux boiler	Facility Total	Standard
hours/yr	3,898.2	4,800	—	—	—
Gross MW	405	405	—	—	—
Gross MW-hr/yr	1,578,771	1,944,000	—	3,522,771	—
Net MW	396.63	396.63	—	—	—
Net MW-hr/yr	1,546,143	1,903,824	—	3,449,967	—
lb CO_2/yr	1,151,083,080	1,464,622,760	1,145,860	2,616,851,699	—
NSPS lb CO_2/MW-hr				743	1,000
SB 1368 lb CO_2/MW-hr				759	1,100

Notes:

1. Unit 1 operational hours based on average capacity factor for 2012 and 2013 (same as emissions)
2. Unit 1 and 2 gross MW based on nameplate capacity; auxiliary load provided by IEEC and subtracted from gross MW to obtain net MW.
3. For facility calculations, all equipment involved in electricity generation is included (two turbines and auxiliary boiler).

CO_2 = carbon dioxide
lb = pound
MW = megawatt
MW-hr = megawatt-hour
MW-hr/yr = megawatt-hours per year
NSPS = new source performance standard
SB = Senate Bill

3.1.4.4 Federal – Prevention of Significant Deterioration Analysis

PSD permitting in the SCAQMD is governed by a partial delegation agreement between the SCAQMD and U.S. EPA. In some cases, the SCAQMD is the permitting authority and evaluates projects pursuant to its Regulation XVII. In other cases, the U.S. EPA is the permitting authority and evaluates projects pursuant to federal regulations at 40 CFR Part 52.21. In general, the SCAQMD issues and modifies PSD permits so long as the applicant does not seek to use certain "additional calculation methodologies" and the permit is not based on a "Plantwide Applicability Limit (PAL)."[18] These "additional calculation methodologies" allow an existing PSD source to calculate the emissions associated with a modification with an actual-to-projected-actual test.[19] The delegation agreement between U.S. EPA and SCAQMD provides that: "[T]his partial delegation of authority to issue and modify PSD permits does not delegate authority to the District to modify PSD permits when the applicant seeks to use the additional calculation methodologies promulgated in 40 CFR 52.21 but not set forth in Regulation XVII…."[20]

IEEC is using the actual-to-projected-actual test for the turbine replacement, which produces a more representative calculation of emissions associated with modifications to existing PSD sources; therefore, U.S. EPA is the PSD permitting authority and the project will be evaluated according to federal regulations. Under the baseline actual-to-projected-actual test, emissions of attainment pollutants would not exceed the PSD significance levels that trigger PSD applicability. However, certain recordkeeping and reporting will be required (e.g., submission of projected-actual emissions estimates to U.S. EPA, submission of annual emissions report to U.S. EPA and maintenance of records for 5 years).[21] IEEC

18 *See* U.S. EPA – SCAQMD Agreement for Partial Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21 (July 25, 2007).
19 *See* 40 CFR Section 52.21.
20 U.S. EPA – SCAQMD Agreement for Partial Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21, at 2 (July 25, 2007).
21 *See* 40 CFR Section 52.21(r)(6)(iii).

therefore proposes a new Condition of Certification, AQSC-18, that will cover this new reporting requirement. Appendix E includes the proposed description and verification.

Rule Paragraph (b)(41)(ii)(c) allows that facility emissions associated with previously unused permitted generating capacity that could have been accommodated by the existing unit (and that are unrelated to the modification) may be subtracted from the PAE. More specifically, the pertinent regulatory language provides:

"In determining the projected actual emissions …, the owner or operator of the major stationary source:

…(c) Shall exclude, in calculating any increase in emissions that results from [t]he particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(48) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth;"

Accordingly, the following emissions have been calculated for Unit 2 before and after the turbine replacement Project:

- BAE, based on any consecutive 24-month period in the last five years (40 CFR Part 52.21 [b][48][i]);
- PAE after the project, based on the maximum annual emissions that IEEC anticipates may occur during the 5 years after project implementation (40 CFR Part 52.21 [b][41][i]); and
- Unused capacity emissions, based on the capacity that the unit could have operated at—if there had been sufficient market demand—in the same period that was used for the BAE (40 CFR Part 52.21 [b][41][ii][c]).

BAE and PAE estimates, and underlying assumptions, are provided and summarized in Table 3-13 for each attainment NSR pollutant. Table 3-13 also compares resulting net emissions increases with applicable PSD significance levels for each pollutant.

Table 3-13
PSD Comparison – Actual to Projected Actual Emissions Test

Pollutant	PAE[1] Baseload (tpy)	PAE[1] Cycling (tpy)	Unused Capacity Emissions[2] (tpy)	BAE[3] (tpy)	Net Increase Baseload (tpy)	Net Increase Cycling (tpy)	PSD Significant Emission Rate	PSD Trigger?
NO_X	79.1	59.9	21.9	24.8	32.4	13.2	40	N
PM_{10}	30.6	18.7	12.8	14.9	2.9	-9.0	10	N
CO	48.9	53.8	7.5	3.6	37.8	42.6	100	N
SO_2	7.5	4.5	3.1	3.6	0.7	-2.3	40	N

Notes:

1. See Appendix B for detailed baseload and cycling scenario assumptions.
2. Unused capacity emissions are based on the potential capacity factor that Unit 2 could have achieved in the baseline period if there had been sufficient market demand. Detailed calculations and assumptions are provided in Appendix B.
3. BAE are based on the highest consecutive two-year period over the last 4 years (third quarter of 2010 through second quarter of 2014). Unit 2 commissioning completed in second quarter of 2010; therefore, only 4 years of historical data are available.

BAE = baseline actual emissions
CO = carbon monoxide
NO_X = nitrogen oxides
PAE = projected actual emission
PM_{10} = particulate matter less than 10 microns in diameter
PSD = Prevention of Significant Deterioration
SO_2 = sulfur dioxide
tpy = tons per year

BAE values are based on 24 months of facility emission data during the past 5 years; however, since commissioning of Unit 2 was completed in the second quarter of 2010, only 4 years of historical data are available. Actual emissions from the period third quarter 2010 through second quarter 2014 were used in this analysis. Emissions over rolling quarterly 24-month periods were averaged, and the highest annual average emission rate for each pollutant was selected as BAE. 40 CFR Part 52.21 (b)(48)(i)(c) allows use of different baseline years for each pollutant. Additionally, it should be noted that in this time frame the facility did not have any period of emissions greater than any legally enforceable limitations; therefore, noncompliant emissions were not subtracted, per 40 CFR Part 52.21 (b)(48)(i)(b).

Determining PAE estimates requires an analysis of the likely future operations of the IEEC. IEEC currently operates in the California Independent System Operator day-ahead merchant market. IEEC considered historical operations and the future market for electrical generation at IEEC in developing future operating scenarios. Estimating future operations of the IEEC depends on many factors, including the projected demand for generation (which, in turn, is driven by a range of factors, such as assumed future economic activity and success of energy efficiency programs), operating costs, price of electricity, and policy assumptions. The U.S. Energy Information Administration (EIA, 2014) has determined that there will be substantial uncertainty in projecting demand for future generation because many of the events that shape energy markets are not fully predictable, and because future developments in technologies, demographics, and resources cannot be foreseen with certainty.[22] In addition to broader uncertainties regarding future demand for generation, a number of local and regional factors may impact the demand for future generation at IEEC, including the shutdown of the San Onofre Nuclear Generating Station, retirement of once-through cooling power plants, and ongoing growth of and need to integrate variable renewable generation.

PAE estimates are provided for two scenarios that bracket the anticipated range of future facility operations after Project implementation. One future scenario represents maximum base-load operation with corresponding startups and shutdowns. The second scenario represents a reasonable maximum cycling scenario, with IEEC providing intermediate cycling capacity and energy and renewables integration support to the grid. Unused capacity emission calculations and assumptions for the baseline period are provided in Appendix B. The calculated unused capacity emissions are not related to the proposed turbine replacement; this capacity factor could have been achieved by the existing Unit 2 7H CT if historic demand for baseload generation had been higher. A Frame 7HA.01 CT is functionally equivalent to the existing 7H unit, and the Project will not increase Unit 2's total permitted generating capacity.

For simplicity, the facility's particulate matter emissions conservatively are assumed to be entirely PM_{10} for this analysis.

As shown in Table 3-13, the project does not trigger PSD review for any attainment pollutant under either scenario. Concurrent with submission of this PTA, IEEC LLC has submitted an analysis to U.S. EPA Region IX demonstrating that the Project does not trigger PSD review. That analysis is included as Appendix F to this PTA.

In the case of *Utility Air Regulatory Group v. EPA*, the U.S. Supreme Court held that emissions of GHGs alone cannot trigger PSD applicability, but that once sources trigger PSD review due to their criteria pollutant emissions, such sources must limit emissions of GHGs through BACT.[23] As shown in Table 3-13, the turbine replacement's criteria pollutant emissions do not exceed the significance levels set

[22] U.S. Energy Information Administration, Annual Energy Outlook 2014 with Projections to 2040, at iii (April 2014) (available online at: http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf). ("Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty.")

[23] 134 S. Ct. 2427, 573 U.S. ___ (2014) (Docket No. 12-1146).

forth in 40 CFR Section 52.21(b)(23); therefore, the Project is not subject to PSD review for GHGs under the federal regulations.

3.2 BIOLOGICAL RESOURCES

The Project is entirely within the existing IEEC site, and does not result in any additional disturbed areas. Most of the equipment laydown, parking areas, and roads are either paved, graveled, or annually maintained (tilled). No new site preparation work, such as grading or excavating, will be required. Therefore, the proposed turbine replacement would not change the analysis of impacts to biological resources as described in the original certification and the 2005 IEEC Amendment. Impacts to biological resources are expected to be less than significant with implementation of the Conditions of Certification that IEEC complies with as part of ongoing operations; these conditions are summarized in Appendix E. Therefore, the proposed Project will not result in any significant impacts in the area of Biological Resources.

3.3 CULTURAL RESOURCES

The Project is entirely within the existing IEEC site, and would not result in any additional disturbed areas beyond the licensed site. Most of the equipment laydown, parking areas, and roads are either paved graveled, or annually maintained (tilled). No new site ground disturbance or preparation work, such as grading or excavating, will be required. There are no ground-disturbance activities associated with replacement of the gas turbine. Therefore, impacts to cultural resources due to the turbine replacement are expected to be less than significant.

3.4 LAND USE

The Project is entirely within the existing IEEC site, and does not alter the analysis of potential impacts to land use resources presented in the original certification and the 2005 IEEC Amendment. At the time of certification, the IEEC site was located in unincorporated Riverside County. The City of Menifee, and therefore the site, was incorporated in 2008. In December 2013, the Menifee City Council approved the city's General Plan and supporting Environmental Impact Report. This included adoption of the previous County of Riverside land use designation (heavy industrial) for the site. Therefore, the IEEC site is still in the Menifee North Specific Plan area and has a land use designation of heavy industrial (City of Menifee, 2013). The Project is consistent with the current development pattern for the area established by the Menifee General Plan and the Menifee North Specific Plan. Therefore, impacts to land use due to the turbine replacement are expected to be less than significant.

3.5 NOISE

The turbine replacement is not expected to result in significant changes to the noise emissions during operations that were modeled and presented in the original certification and the 2005 IEEC Amendment. The turbine will be located inside an equipment cabinet within the IEEC site, similar to and in the same location as the existing turbine. Because there will be no steam or air blows associated with the turbine replacement, all noise monitoring will be conducted under existing operational programs that are compliant with the Occupational Safety and Health Administration. To verify that far field receptors will not be impacted above noise significance levels, IEEC proposes to conduct a new study once the new 7HA.01 is fully operational in conjunction with Unit 1 operations. Condition of Certification NOISE-6 requires that IEEC conduct a noise study to demonstrate compliance with applicable noise limits. In the event that results of the study indicate that the noise level due to plant operations exceeds 45 A-weighted decibels for any given hour during a 25-hour period, Condition of Certification NOISE-6 requires that mitigation measures be implemented to reduce noise to a level of compliance with these limits. With the implementation of Condition of Certification NOISE-6, described above and in Appendix E, impacts would be less than significant.

3.6 PUBLIC HEALTH

Based on the potential emissions minus baseline emissions in Table 3-5, the IEEC could have higher emissions following implementation of the replacement Project. However, the total emissions from the IEEC will not exceed the emissions considered in the original certification, the 2005 IEEC Amendment health risk assessments (HRAs), or the findings in the CEC's Decision that health risks from the mitigated project emissions are below levels of significance. In addition, after the Project, total toxic air contaminants from the IEEC will not increase above the levels analyzed by the original certification and 2005 IEEC Amendment, because the IEEC will continue to use pipeline-quality natural gas to operate the gas turbine. In addition, the location of the emission points will not be affected by the Project.

The distance to the nearest residential receptor has not changed from the original certification. There are no new nearby sensitive receptors (residential areas, schools, hospitals) since the previous public health evaluation was completed.

For all of the reasons set forth above, the HRA conducted in connection with the original certification of the IEEC and the 2005 IEEC Amendment provide an accurate assessment of the public health risks associated with the IEEC following implementation of the Project. The previously completed HRA found that health risks associated with the IEEC were well below significance levels for both cancer and non-carcinogenic risks. Therefore, the risks from the IEEC following replacement of the turbine would also be well below the significance criteria. The IEEC will continue to be in compliance with Toxic BACT. Therefore, operation of the IEEC with the new 7HA.01 gas turbine will pose a less-than-significant health risk to nearby populations.

3.7 WORKER SAFETY AND FIRE PROTECTION

The Project is entirely within the existing IEEC site, and would not change the anticipated workplace hazards or require changes to the safety programs presented in the original IEEC certification and the 2005 IEEC Amendment.

Potential impacts to worker safety and health are expected to be less than significant with implementation of Conditions of Certification that IEEC complies with as part of ongoing operations; these conditions are summarized in Appendix E.

3.8 SOCIOECONOMICS

The Project is entirely within the existing IEEC site, and would not alter the analysis of potential socioeconomic impacts presented in the original certification and the 2000 IEEC Amendment. The analysis concluded the IEEC would not induce substantial growth or concentration of population; induce substantial increases in demand for public service and utilities; displace a large number of people; disrupt or divide an established community; or result in disproportionate adverse effects on minority or low-income populations. Therefore, impacts due to the turbine replacement to socioeconomics are expected to be less than significant.

3.9 SOILS

The Project is entirely within the existing IEEC site, and does not result in any additional disturbed areas. Most of the equipment laydown, parking areas, and roads are either paved, graveled, or annually maintained (tilled). No new site preparation work, such as grading or excavating, is required. Therefore, impacts due to the turbine replacement to soil resources are expected to be less than significant.

3.10 TRAFFIC AND TRANSPORTATION

The Project is entirely within the existing IEEC site, and would not alter the analysis of potential traffic and transportation impacts presented in the original IEEC certification and the 2005 IEEC Amendment, including roadway and intersection levels of service during project operation, and potential impacts to transportation networks. As described in Section 2.2, Replacement Activities, and discussed in Subsection 3.1.2, Replacement Activity Emissions, installation activities associated with the gas turbine replacement will take less time and have significantly fewer worker and delivery trips than previously analyzed during original IEEC certification and the 2005 IEEC Amendment, which were determined to have less-than-significant impacts. There is expected to be no change in the number of worker or delivery trips during operations. Therefore, potential traffic and transportation impacts are expected to be less than significant with implementation of the Conditions of Certification described in Appendix E.

3.11 VISUAL RESOURCES

The Project includes replacement of the gas turbine for Unit 2, as shown on Figure 2-1. The new turbine will be inside an equipment cabinet, similar in size and in the same location as the existing turbine that it replaces. These changes will be visually imperceptible when the IEEC is viewed as a whole following replacement of the turbine. There are no changes to the overall plant configuration, exhaust stacks, or cooling towers; therefore, no significant changes to visual plumes are expected. The proposed turbine replacement will not modify the existing analysis or conclusions presented in the original IEEC certification and the 2005 IEEC Amendment. Therefore, visual impacts due to the turbine replacement are expected to remain less than significant.

3.12 HAZARDOUS MATERIALS

The Project would not substantially change the types or quantities of hazardous materials used at the IEEC during the replacement activities or during operations. Therefore, potential hazardous materials handling impacts are expected to be less than significant with implementation of the applicable Conditions of Certification that IEEC complies with as part of ongoing operations; these conditions are summarized in Appendix E.

3.13 WASTE MANAGEMENT

The Project would not substantially change the types, quantities, or frequencies of wastes generated by the project during the turbine replacement or during operations. Most of the existing 7H turbine that would be removed from Unit 2 would be stored on site and used as spare parts for Unit 1. The remainder would be recycled as scrap metal or sent back to GE’s Greenville, South Carolina facility. Impacts related to waste management are expected to be less than significant with implementation of the Conditions of Certification that IEEC complies with as part of ongoing operations; these conditions are summarized in Appendix E.

3.14 WATER RESOURCES

With implementation of the Project, the IEEC would continue to use recycled water provided by the EMWD. The IEEC’s use of recycled water for power plant cooling is consistent with the CEC’s 2003 Integrated Energy Policy Report and the State Water Resources Control Board Resolution 75-58, which encourage the use of water sources other than fresh water for cooling purposes. The 2005 IEEC Amendment projected a maximum annual usage of 4,842 acre-feet per year of recycled water based on 100 percent load (IEEC, 2005; CEC, 2005a). There would be no increase in the IEEC’s projected maximum potential annual use of water as a result of the Project. The new 7HA.01 is an air-cooled CT, instead of a steam-cooled CT like the current turbine. This change in cooling of the turbine is expected to reduce the amount of recycled water used by approximately 4 percent on an average annual basis. The steam cycle for Unit 2, which consumes most of the water demand, will not change and will remain a close cycle system.

The Project would not result in changes to the analysis of water quality or flood hazards as described in the original certification or the 2005 IEEC Amendment. Impacts to water resources are expected to be less than significant with implementation of the Conditions of Certification that IEEC complies with as part of ongoing operations; these conditions are summarized in Appendix E.

3.15 GEOLOGIC HAZARDS AND RESOURCES

The Project is entirely within the existing IEEC site, and would not result in changes to the analysis of geologic hazards described in the original certification or the 2005 IEEC Amendment, or result in significant adverse impacts to the geologic environment. Therefore, as described in the original certification and the 2005 IEEC Amendment, impacts to geologic hazards and resources are expected to be less than significant.

3.16 PALEONTOLOGICAL RESOURCES

The Project is entirely within the existing IEEC site, and does not result in any additional disturbed areas. Most of the equipment laydown, parking areas, and roads are either paved, graveled, or annually maintained (tilled). No new site ground disturbance or preparation work, such as grading or excavating, will be required. Therefore, impacts to paleontological resources due to the turbine replacement are expected to be less than significant.

3.17 CUMULATIVE IMPACTS

Installation of the replacement turbine will occur over a relatively short period of time, and entirely within the existing IEEC site and on previously disturbed areas. Installation of the replacement turbine will not result in any significant environmental impacts. Given the limited scope of the Project and the temporary nature of the installation activities, installation of the turbine is not expected to result in a significant cumulative impact.

With respect to Project operations, as discussed in the preceding sections, the proposed turbine replacement would not individually result in any significant environmental impacts. Given the limited scope of the Project as a functionally identical replacement within the existing IEEC footprint, and given that the IEEC is an existing power plant in an industrial area, there is limited potential for the Project to contribute to a significant environmental impact. As a result, project operations are not expected to result in a significant cumulative impact.

Specifically with respect to potential cumulative air quality impacts, the existing ambient conditions are similar to those at the time of the original certification and IEEC 2005 Amendment, and as indicated in Table 3-2 have improved to some extent. Compliance with the federal and California Clean Air Acts requires the SCAQMD to adopt, implement, and periodically update region-wide air quality management plans (AQMPs) that specify the steps necessary to achieve attainment with ambient air quality standards. The AQMP includes baseline and future year emission inventories, population and economic growth projections, and control measures that enable the region to demonstrate future attainment. Programmatic control measures that are part of the attainment planning process in the AQMP include the NSR requirements described in the Air Quality section, with which the Project will comply. Compliance with the NSR requirements ensures that Project-related emissions occur in a manner that would be consistent with the AQMP. By being consistent with the SCAQMD AQMP, the proposed project would not be likely to cause a significant regional cumulative impact.

To address the potential for more localized cumulative impacts, IEEC requested information from SCAQMD regarding new or proposed emission sources that have been sited within 6 miles of the IEEC since it was initially permitted. On August 26, 2014, SCAQMD confirmed that there are no new emission sources within a 6-mile radius of the IEEC. Therefore, localized cumulative impacts would be similar to those previously analyzed in the original certification and the 2005 IEEC Amendment, which were found to be less than significant.

3.18 ENVIRONMENTAL JUSTICE

Although minority and low-income populations exist in the vicinity of the IEEC, the Project will not result in any significant environmental impacts during installation of the replacement turbine or operations following replacement of the turbine. As a result, the Project will not cause a disproportionate adverse impact to an environmental justice community.

4.0 ENGINEERING ANALYSIS

4.1 POWER PLANT RELIABILITY

The flange-to-flange replacement of Unit 2's gas turbine with the proposed new gas turbine would not affect the reliability of the IEEC as a whole. As a result, the project would not significantly change the IEEC's reliability compared to what was analyzed in the original IEEC certification.

4.2 POWER PLANT EFFICIENCY

One of the main benefits of the new 7HA.01 turbine is that it is more efficient than the existing 7H turbine; therefore, the Project would improve the overall efficiency of the IEEC. As a result, the Project would not adversely affect the efficiency of the IEEC compared to what was analyzed in the original IEEC certification and 2005 IEEC Amendment, and would in fact provide additional benefits.

4.3 TRANSMISSION SYSTEM ENGINEERING

Because the replacement of the existing 7H turbine with the new 7HA.01 turbine will continue to be a single-shaft configuration, and will result in the same nominal nameplate rating for Unit 2 (405 MW), the project will not trigger the need for changes to the transmission system for the IEEC. As a result, the project would not adversely affect the transmission system engineering of the IEEC compared to what was analyzed in the original IEEC certification.

5.0 ALTERNATIVES

CEQA requires discussion of reasonable project alternatives that would "feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any significant impacts of the project and evaluate the comparative merits of the alternatives" (CEQA Guidelines Section 15126.6). The specific alternative of "no project" is also to be considered along with its impact (CEQA Guidelines Section 15126.6[e][1]).

As discussed above, the Project will not have any significant environmental impacts. Therefore, the scope of the inquiry into alternatives to the Project that would avoid or substantially lessen any significant impacts associated with the Project may be limited.

Furthermore, given the Project's very specific and narrow objective of demonstrating the successful performance of the 7HA.01 turbine, there are few if any alternatives that would feasibly attain the basic objectives of the Project. Deployment of alternative technologies does not make any sense since the specific objective of the Project is to demonstrate the technology being proposed. Similarly, deployment of the proposed technology at an alternative location does not make sense since the IEEC, both in terms of its existing configuration and its ownership and operational control, provides an ideal and unique opportunity to deploy and demonstrate the 7HA.01 turbine. Deployment of the technology at a new greenfield site would have substantially greater environmental impacts than the proposed Project. The "no project" alternative would not accomplish the primary objective of the Project, which is to deploy and demonstrate the proposed turbine technology.

6.0 REFERENCES

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SJVAPCD (San Joaquin Valley Air Pollution Control District), 2014. CEQA Determinations of Significance for Projects Subject to ARB's GHG Cap-and-Trade Regulation, APR – 2030. June 25.

U.S. EPA (Environmental Protection Agency), 2011. "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard." Memo from Tyler Fox, March 2011.

APPENDIX A
LIST OF PROPERTY OWNERS

List of Property Owners and Tenants

APN	MAIL_TO_NAME	MAIL_TO_STREET	MAIL_TO_CITY	MAIL_TO_ZIP
329141005	EASTERN MUNICIPAL WATER DIST	P O BOX 8300	PERRIS CA	92572
331180004	RIVERSIDE COUNTY TRANSPORTATION COMMISSION	PO BOX 12008	RIVERSIDE CA	92502
329120026	PMB 303	541 N MAIN ST STE 104	CORONA CA	92880
329141003	PAMELA GOURLEY	5501 ST ANDREWS CT	PLANO TX	75093
329120040	C/O REAL PROP DIV	P O BOX 1180	RIVERSIDE CA	92502
329141008	PAMELA GOURLEY	5501 ST ANDREWS CT	PLANO TX	75093
331150045	HANCOCK PROP	P O BOX 890700	TEMECULA CA	92589
331170018	WILIAM A ALLEN	11281 DEL DIABLO WAY	SAN DIEGO CA	92129
331180018	C/O E PROPERTY TAX WESTIN	P O BOX 4900 DEPT 201	SCOTTSDALE AZ	85261
331150025	C/O CLEMENTINA RUVALCABA	26450 DAWSON RD	ROMOLAND CA	92585
329120041	C/O REAL PROP DIV	P O BOX 1180	RIVERSIDE CA	92502
331190034	DFA	4241 S ARVILLE ST	LAS VEGAS NV	89103
331190014	C/O GROVE LUMBER	1351 S CAMPUS AVE	ONTARIO CA	91761
331210009	C/O CARL JOHNSON	512 CHANEY ST	LAKE ELSINORE CA	92530
331150039	DELPHI MARKETING SYSTEMS	631 N STEPHANIE ST NO 490	HENDERSON NV	89014
331170025	JOSE A AND GUADALUPE RODRIQUEZ, ROSALBA LLAMAS	23411 WESTERN RIDGE	MORENO VALLEY CA	92557
331180016	C S REENDERS ASST COMPTROLLER	P O BOX 800	ROSEMEAD CA	91770
331170017	JAN FRENCH	P O BOX 1205	ROMOLAND CA	92585
331150044	TRUMBLE PROP	61 ARGONAUT	ALISO VIEJO CA	92656
331180012	DATATRONICS INC	28151 HIGHWAY 74	ROMOLAND CA	92585
331150043	C/O MARY SAENZ	512 CHANEY ST	LAKE ELSINORE CA	92530
331150037	MOTTE TOWNE CENTER	445 S D ST	PERRIS CA	92570
331150024	JOHN VAL AND LEYSA SWANSON GENTILLON	4004 LAGO DI GRATA	SAN DIEGO CA	92130
331180007	WALTER A, IRENE S AND RITA REGGIO	1049 OBISPO AVE	LONG BEACH CA	90804
331170026	C/O JEANNE DERINGER	470 E HARRISON ST	CORONA CA	92879
331190041	RAYMOND AND SUSAN CROLL	1351 S CAMPUS AVE	ONTARIO CA	91761
331150016	DUANE L AND SANDRA D WALSTON	P O BOX 264	HEMET CA	92546
329141006	RIVERSIDE COUNTY TRANSPORTATION COMMISSION	PO BOX 12008	RIVERSIDE CA	92502
331190010	C/O GROVE LUMBER	1351 S CAMPUS AVE	ONTARIO CA	91761
331190033	DFA	4241 S ARVILLE ST	LAS VEGAS NV	89103
331150013	ABRAHAM L PEREZ	27861 ETHANAC RD	SUN CITY CA	92585
331180015	C/O WYROC MATERIALS	P O BOX 1239	VISTA CA	92085
331150031	SOUTHERN CALIFORNIA EDISON CO	14799 CHESTNUT ST	WESTMINSTER CA	92683
331150042	JOHN VAL AND LEYSA SWANSON GENTILLON	4004 LAGO DI GRATA	SAN DIEGO CA	92130
331150046	MARK ZANELLI	23498 UNDERWOOD CIR	MURRIETA CA	92562
329262014	MIGUEL A LEYVA	25964 NORTH WINDS DR	ROMOLAND CA	92585
329263013	MARIA ANDRADE	25946 WEST WINDS DR	ROMOLAND CA	92585
329120018	C/O REAL PROP DIV	P O BOX 1180	RIVERSIDE CA	92502
329120031	RIVERSIDE COUNTY TRANSPORTATION COMMISSION	PO BOX 12008	RIVERSIDE CA	92502
329261009	JOSE AND DOLORES OCHOA	25965 NORTH WINDS DR	ROMOLAND CA	92585
329261001	RAUL AND VIRGINIA RIESTRA	28235 SPRINGS WINDS DR	ROMOLAND CA	92585
329264016	JUAN M VENEGAS AND MARIA M BELTRAN	24866 CAPE COD ST	MORENO VALLEY CA	92553
329110006	C/O THOMAS A MAULHARDT	3820 GOLDENROD ST	SEAL BEACH CA	90740
329264015	ALFREDO DE LA TORRE DONATO	926 MURRIETA RD	PERRIS CA	92571
329263016	ALEXIS M ALVAREZ	25943 TRADE WINDS DR	ROMOLAND CA	92585
329261008	ROCIO HEIL	13716 BIGHORN TRL	WILLIS TX	77378
329262016	ROBERT L AND ANNA L SMITH	25945 WEST WINDS DR	ROMOLAND CA	92585
329261003	LELAND D LINDA MARY SIGLEY	28205 SPRING WINDS DR	ROMOLAND CA	92585
329261002	BRADLEY JOHN ALLANACH	28211 SPRING WINDS DR	MENIFEE CA	92585
329261006	SEAN SPICER AND DEBORAH QUINN	28165 SPRING WINDS DR	ROMOLAND CA	92585
329261004	ISRAEL GRIJALVA MENENDEZ AND JOSEFINA GRIJALVA	28191 SPRING WINDS DR	ROMOLAND CA	92585
329261010	MAYRA C VELAZCO HASAN	25941 NORTH WINDS DR	ROMOLAND CA	92585
329142007	SHARON K FIELDS	27888 VAN BUREN AVE	ROMOLAND CA	92585
329261007	DEBORAH M QUINN	28135 SPRING WINDS DR	ROMOLAND CA	92585
329110022	HSUE CHIN LIN	448 MIDDLEBURY CT	CLAREMONT CA	91711
329261005	ROBERT A MORRIS	28175 SPRING WINDS DR	ROMOLAND CA	92585
329263015	JORGE CORTEZ	25961 TRADE WINDS DR	ROMOLAND CA	92585
329142009	TERESA GONZALEZ DEGARDNER	27912 ETHANAC RD	ROMOLAND CA	92585
329142008	MARTIN AND SOLEDAD AGUIRRE	27894 VAN BUREN AVE	ROMOLAND CA	92585
329262015	KENNETH EUGENE FLINT	25963 WEST WINDS DR	ROMOLAND CA	92585
329263014	JESUS FERNANDO DIAZ AND ROSA ELENA CERVANTES	25962 WEST WINDS DR	ROMOLAND CA	92585

List of Property Owners and Tenants

APN	MAIL_TO_NAME	MAIL_TO_STREET	MAIL_TO_CITY	MAIL_TO_ZIP
329264014	DINA E ZAYAS	P O BOX 2463	HEMET CA	92546
329143004	HOYT J AND OMA L BIBBY	27865 VAN BUREN AVE	ROMOLAND CA	92585
329262013	JULIAN AND LISA LOZANO	25942 NORTH WINDS DR	ROMOLAND CA	92585
331150004	EDDIE AND PEARL ROUSSELL	50694 HIGHWAY 31	LA PINE OR	97739
331150027	VINCENT J AND PEGGY S STAGLIANO	5501 ST ANDREWS CT	PLANO TX	75093
331150017	PAUL E AND DELORES C PHILLIPS	28797 BELMONT CT	SUN CITY CA	92586
331190046	C/O CARL JOHNSON	512 CHANEY ST	LAKE ELSINORE CA	92530
331180014	C/O WYROC MATERIALS	P O BOX 1239	VISTA CA	92085
331190044	ICENOGLE MACHINE INC	P O BOX 249	WINCHESTER CA	92596
331190045	JAMES NICHOLAS AN D CHARLOTTE JONES	P O BOX 1179	ROMOLAND CA	92585
331150040	MICHAEL J AND ANNE M GRABOWSKI	12018 CENTRAL AVE	CHINO CA	91710
331190039	ARNOLD BRIAN	P O BOX 1207	RICHMOND TX	77406
331180002	DATATRONICS INC	28151 HIGHWAY 74	ROMOLAND CA	92585
331180006	C/O WYROC MATERIALS	P O BOX 1239	VISTA CA	92085
331150018	VINCENT J AND PEGGY S STAGLIANO	5501 ST ANDREWS CT	PLANO TX	75093
331150036	C/O PAUL E WHITE	1000 KIEWIT PLAZA	OMAHA NE	68131
331150041	ENGINEERING PROP	2115 LA MIRADA DR	VISTA CA	92083
331190006	RIVERSIDE COUNTY TRANSPORTATION COMMISSION	PO BOX 12008	RIVERSIDE CA	92502
331190052	RAYMOND AND SUSAN CROLL	1351 S CAMPUS AVE	ONTARIO CA	91761
331150005	ABRAHAM L PEREZ	27861 ETHANAC RD	SUN CITY CA	92585
331190047	RAYMOND AND SUSAN CROLL	1351 S CAMPUS AVE	ONTARIO CA	91761
331190017	RAYMOND AND SUSAN CROLL	1351 S CAMPUS AVE	ONTARIO CA	91761
331190011	C/O GROVE LUMBER	1351 S CAMPUS AVE	ONTARIO CA	91761
331190051	RAYMOND AND SUSAN CROLL	1351 S CAMPUS AVE	ONTARIO CA	91761
331200019	JAMES AND B MARLENE NADIR	3011 S HACIENDA BLV	HACIENDA HEIGHTS CA	91745
331200018	JAMES AND B MARLENE NADIR	3011 S HACIENDA BLV	HACIENDA HEIGHTS CA	91745
331210025	JON AND TERRY V TORRES	20590 MAGNOLIA AVE	NUEVO CA	92567
331210008	ROMOLAND 64	41391 KALMIA ST 200	MURRIETA CA	92562
331210026	JOSEPH AND PAMELA ROSA	29215 CALLE DE CABALLOS	ROMOLAND CA	92585
331210020	VAN L DAVIS, CHARLIE D AND LINDA R EATON	1525 GRAND AVE	SAN MARCOS CA	92078
331210019	VAN L DAVIS, CHARLIE D AND LINDA R EATON	1525 GRAND AVE	SAN MARCOS CA	92078
331170027	C/O JEANNE DERINGER	470 E HARRISON ST	CORONA CA	92879
331210021	VAN L DAVIS, CHARLIE D AND LINDA R EATON	1525 GRAND AVE	SAN MARCOS CA	92078
331200022	ROBERT ERIC AND RACHEL ROSELYN JIMENEZ	7951 ARLINGTON AVE	RIVERSIDE CA	92503
331190053	C/O GROVE LUMBER	1351 S CAMPUS AVEN	ONTARIO CA	91761
331200013	GILBERT AND JOYCE T LYNCH	29482 VISTA VALLEY DR	VISTA CA	92084
331200020	JAMES AND B MARLENE NADIR	3011 S HACIENDA BLV	HACIENDA HEIGHTS CA	91745
331200024	ROBERT ERIC AND RACHEL ROSELYN JIMENEZ	7951 ARLINGTON AVE	RIVERSIDE CA	92503
331210027	C/O DENNIS CHAPMAN	1522 BROOKHOLLOW DR STE 1	SANTA ANA CA	92705
331200023	ROBERT ERIC AND RACHEL ROSELYN JIMENEZ	7951 ARLINGTON AVE	RIVERSIDE CA	92503
331200012	C/O GILBERT G LYNCH	29482 VISTA VALLEY DR	VISTA CA	92084
331210012	VENUS PROP	27250 NICOLAS RD NO A149	TEMECULA CA	92591

APPENDIX B
AIR QUALITY EMISSION CALCULATIONS

Combined Cycle Systems Emissions Estimates

OPERATING POINT		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Case Description		Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
SITE CONDITIONS																	
Ambient Temperature	°F	22.6	22.6	22.6	59	59	59	63	63	63	95	95	95	112	112	112	112
Ambient Pressure	psia	13.957	13.957	13.957	13.957	13.957	13.957	13.957	13.957	13.957	13.957	13.957	13.957	13.957	13.957	13.957	13.957
Ambient Relative Humidity	%	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	23.5	23.5	23.5	10.0	10.0	10.0	10.0
PLANT STATUS																	
HRSG Duct Burner		Not Present	Not Present	Not Present	Not Present	Not Present	Not Present	Not Present	Not Present	Not Present	Not Present	Not Present	Not Present	Not Present	Not Present	Not Present	Not Present
SCR		Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating
CO Catalyst		Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating	Operating
Inlet Chiller state (On or Off)		Off	Off	Off	Off	Off	Off	On	Off	Off	On	Off	Off	On	Off	Off	Off
Gas Turbine Load	%	Base	65%	30%	Base	65%	30%	Base	65%	31%	Base	70%	39%	Base	Base	80%	61%
Gas Turbines Operating		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
GT Diluent Injection Type		None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
GT Diluent Injection Flow (per GT)	10^3 lb/hr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PLANT PERFORMANCE SUMMARY	**Without Permiting Margin, Not Guaranteed, See HRSG NOTE 9**																
GTG output (total all GTs)	**kW**	**268964**	**174992**	**81327**	**257590**	**167621**	**77941**	**265108**	**165294**	**79342**	**265113**	**155011**	**86286**	**265088**	**200981**	**160926**	**122928**
STG output	**kW**	**126130**	**97991**	**74282**	**129369**	**97709**	**73123**	**129097**	**96835**	**73279**	**126106**	**92972**	**73792**	**125373**	**114247**	**95725**	**83645**
Gross Power output	**kW**	**395094**	**272983**	**155609**	**386960**	**265330**	**151064**	**394205**	**262130**	**152622**	**391219**	**247983**	**160078**	**390460**	**315228**	**256651**	**206573**
Plant Heat Consumption	**MMBTU/hr, HHV**	**2453**	**1760**	**1144**	**2374**	**1698**	**1095**	**2432**	**1681**	**1103**	**2433**	**1600**	**1139**	**2432**	**1962**	**1639**	**1378**
Gross Heat Rate	**BTU/kW-hr, HHV**	**6209**	**6447**	**7350**	**6135**	**6399**	**7247**	**6171**	**6412**	**7230**	**6218**	**6451**	**7114**	**6229**	**6223**	**6387**	**6673**
FUEL DATA																	
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
HHV	**BTU/lb**	**22796**	**22792**	**22792**	**22796**	**22792**	**22792**	**22796**	**22792**	**22792**	**22796**	**22792**	**22792**	**22796**	**22796**	**22792**	**22792**
LHV	**BTU/lb**	**20555**	**20555**	**20555**	**20555**	**20555**	**20555**	**20555**	**20555**	**20555**	**20555**	**20555**	**20555**	**20555**	**20555**	**20555**	**20555**
Fuel Mol. Wt.	**lb/mole**	**16.38**	**16.38**	**16.38**	**16.38**	**16.38**	**16.38**	**16.38**	**16.38**	**16.38**	**16.38**	**16.38**	**16.38**	**16.38**	**16.38**	**16.38**	**16.38**
Fuel Bound Nitrogen	Wt %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Sulfur Content	ppmw	7.13	7.13	7.13	7.13	7.13	7.13	7.13	7.13	7.13	7.13	7.13	7.13	7.13	7.13	7.13	7.13
GT Heat Consumption per unit with Permitting Margin See HRSG NOTE 9	**MMBTU/hr, HHV**	**2575.6**	**1847.9**	**1200.9**	**2492.9**	**1782.8**	**1149.5**	**2554.1**	**1764.9**	**1158.6**	**2554.2**	**1679.7**	**1195.7**	**2553.7**	**2059.7**	**1721.2**	**1447.4**
Duct Burner Heat Consumption	MMBTU/hr, HHV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GT EXHAUST CONDITIONS (PER GT)																	
Composition:																	
Ar	mol %	0.8901	0.8909	0.8943	0.8836	0.8859	0.8889	0.8824	0.8849	0.8877	0.8822	0.8831	0.8849	0.8830	0.8840	0.8871	0.8887
CO_2	mol %	4.1394	4.0515	3.6843	4.1696	3.9221	3.5901	4.1706	3.9013	3.5929	4.1708	3.7633	3.5747	4.1701	4.0633	3.7299	3.5497
H_2O	mol %	8.2279	8.0563	7.3397	8.9521	8.4709	7.8254	9.0862	8.5629	7.9637	9.1015	8.6148	8.2489	9.0151	8.8075	8.1595	7.8092
N_2	mol %	74.77	74.84	75.12	74.23	74.42	74.67	74.13	74.33	74.57	74.11	74.19	74.33	74.18	74.26	74.52	74.65
O_2	mol %	11.97	12.16	12.96	11.76	12.30	13.02	11.73	12.32	12.99	11.73	12.55	12.96	11.75	11.98	12.71	13.10
Exhaust Gas Molecular Wt	mol %	28.44	28.45	28.49	28.36	28.39	28.43	28.35	28.38	28.42	28.34	28.36	28.38	28.35	28.37	28.41	28.43
Temperature	°F	1121.3	1162.1	1225.0	1165.1	1162.1	1225.0	1150.3	1162.1	1225.0	1150.4	1162.1	1225.0	1150.3	1221.2	1162.1	1162.1
Mass Flow to HRSG	lb/hr	4732000	3457400	2442500	4534300	3439500	2394600	4642000	3421600	2411200	4641800	3381400	2505900	4643100	3845900	3509100	3087100
GT EXHAUST EMISSIONS (PER GT)																	
NOx	**ppmvd @ 15% O2**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**
NOx	**lb/hr as NO2**	**187**	**134**	**85.6**	**181**	**129**	**82**	**186**	**128**	**82.6**	**186**	**122**	**85.5**	**186**	**150**	**125**	**104**
CO	**ppmvd**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**
CO	**lb/hr**	**38.5**	**28.2**	**20**	**36.7**	**27.9**	**19.6**	**37.5**	**27.8**	**19.7**	**37.5**	**27.5**	**20.4**	**37.5**	**31.2**	**28.6**	**25.2**
VOC	**ppmvw**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**
VOC	**lb/hr as methane**	**3.73**	**2.72**	**1.92**	**3.58**	**2.71**	**1.89**	**3.67**	**2.7**	**1.9**	**3.67**	**2.67**	**1.98**	**3.67**	**3.04**	**2.77**	**2.43**
Particulates - Filterable + Condensible, Including Sulfates	**lb/hr**	**6.44**	**6.43**	**6.42**	**6.44**	**6.43**	**6.42**	**6.44**	**6.43**	**6.42**	**6.44**	**6.43**	**6.42**	**6.44**	**6.44**	**6.43**	**6.42**

Combined Cycle Systems Emissions Estimates

OPERATING POINT		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
HRSG DATA (PER UNIT)																	
HRSG EXIT EXHAUST GAS																	
Composition:																	
Ar	mol %	0.89	0.89	0.89	0.88	0.89	0.89	0.88	0.88	0.89	0.88	0.88	0.88	0.88	0.88	0.89	0.89
CO2	mol %	4.14	4.05	3.68	4.17	3.92	3.59	4.17	3.90	3.59	4.17	3.76	3.57	4.17	4.06	3.73	3.55
H2O	mol %	8.23	8.06	7.34	8.95	8.47	7.83	9.09	8.56	7.96	9.10	8.61	8.25	9.02	8.81	8.16	7.81
N2	mol %	74.77	74.84	75.12	74.23	74.42	74.67	74.13	74.33	74.57	74.11	74.19	74.33	74.18	74.26	74.52	74.65
O2	mol %	11.97	12.16	12.96	11.76	12.30	13.02	11.73	12.32	12.99	11.73	12.55	12.96	11.75	11.98	12.71	13.10
Molecular weight		28.44	28.45	28.49	28.36	28.39	28.43	28.35	28.38	28.42	28.34	28.36	28.38	28.35	28.37	28.41	28.43
Temperature	°F	186	176	162	181	176	161	184	177	162	190	183	169	191	178	184	182
Mass Flow	lb/hr	4732000	3457400	2442500	4534300	3439500	2394600	4642000	3421600	2411200	4641800	3381400	2505900	4643100	3845900	3509100	3087100
Actual Volume Flow	Actual ft3/hr	82579000	59379000	40959000	78758000	59192000	40196000	81101000	59008000	40587000	81806000	58882000	42704000	81935000	66454000	61167000	53583000
	ACFM	1376316.667	989650	682650	1312633.333	986533.3333	669933.3333	1351683.333	983466.6667	676450	1363433.333	981366.667	711733.33	1365583.3	1107566.7	1019450	893050
HRSG EXIT EXHAUST GAS EMISSIONS																	
NOx	ppmvd @ 15% O2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
NOx	lb/hr as NO2	18.7	13.4	8.56	18.1	12.9	8.2	18.6	12.8	8.26	18.6	12.2	8.55	18.6	15	12.5	10.4
CO	ppmvd @ 15% O2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CO	lb/hr	11.4	8.14	5.21	11	7.85	4.99	11.3	7.77	5.03	11.3	7.41	5.21	11.3	9.11	7.61	6.36
VOC	ppmvd @ 15% O2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
VOC	lb/hr as methane	3.25	2.33	1.49	3.15	2.24	1.43	3.23	2.22	1.44	3.23	2.12	1.49	3.23	2.6	2.17	1.82
CO2	lb/hr	303000	217000	139000	293000	209000	133000	301000	207000	134000	301000	197000	139000	301000	242000	203000	170000
NH3	ppmvd @ 15% O2	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
NH3	lb/hr	17.3	12.4	7.91	16.7	11.9	7.57	17.1	11.8	7.64	17.1	11.2	7.9	17.1	13.8	11.5	9.65
SOx	ppmvd @ 15% O2	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
SOx	lb/hr as SO2	1.83	1.32	0.85	1.77	1.27	0.82	1.82	1.25	0.82	1.82	1.19	0.85	1.82	1.47	1.23	1.03
Particulates - Filterable + Condensible, Including Sulfates	lb/hr	7.5	7.2	6.9	7.5	7.2	6.9	7.5	7.2	6.9	7.5	7.1	6.9	7.5	7.3	7.1	7

The notes page is an integral part of this document and must be reviewed prior to use of this data.

GT Emission Notes

1. Gas turbine is in steady-state operation.
2. Emissions are based on GE recommended measurement methods GEK 28172.
3. NG = Natural Gas, DO = Distillate Oil, SG = Syngas
4. Reference conditions for SCF are: 68°F, and 14.6959 psia.
5. Reference conditions for Nm3 are: 32°F, and 14.6959 psia.

HRSG Emission Notes:

1. Gas turbine(s) and steam plant are in steady-state operation.
2. HRSG Stack Exhaust emissions are reported based on the following conversion rates:
   - Gas Turbine: 95% conversion of sulfur to SO_2 and 5% conversion to SO_3.
   - For installations that are equipped with a CO catalyst it is expected that 10% to about 35% of the SO_2 in the exhaust gas is converted to SO_3. The actual conversion rate used in these calculations is 30%.
   - For installations with an SCR catalyst for NOx abatement it is expected that 1% to 5% of the SO_2 in the exhaust gas will be converted to SO_3. The actual conversion rate used in these calculations is 5%.
3. HRSG Stack NH_3 Emissions are based on assuming no conversion to ammonium salts
4. Steady State Emissions data above are estimated values based on GE recommended measurements and analysis procedures, per GEK 28172.
5. Reference conditions for exhaust gas SCF are: 68°F, and 14.6959 psia.
   Reference conditions for exhaust gas fuel SCF are: 60°F, and 14.6959 psia.
6. Reference conditions for exhaust gas Nm3 are: 32°F, and 14.6959 psia.
   Reference conditions for gas fuel Nm3 are: 60°F, and 14.6959 psia.
7. SO_2 emission values have been estimated by assuming that all the sulfur in the fuel is converted to SO_2 and is based on maximum S content in the fuel of 7.133 ppmw for gas.
   SO_2 values are margined by 13.7% to account for variation in fuel sulfur content and measurement error.
8. The CO_2 estimate derived from the heat rate does not include any margin for measurement errors assuming that the compliance will be demonstrated using the heat rate from the performance test results. If CO_2 compliance is to be demonstrated using actual CO_2 measurements from the HRSG stack, GE recommends adding 10% margin to the estimated values.
9. The estimated values for heat consumption and the exhaust flows are margined at 5% in this document to account for equipment variations, site operating conditions and life-cycle operating parameters.
   The Plant Performance section does not include permitting margin, for more information on performance please refer to the Heat Balance.

Additional Notes for Particulate Emissions

1. Particulate Matter estimates over the entire emissions compliance region of GT operation are based on field data obtained at base load for the GT. In reality, particulate matter emissions measured in lb/h are expected to decrease at part load operation and the lb/MMBTU values at part load operation are expected not to exceed the lb/MMBTU value for PM at baseload.
2. PM10 and PM2.5 are estimated at the same rate as Total Particulates.
3. PM estimates are based on maximum S content in the fuel of 7.133 ppmw for gas.

Testing and Tuning Emissions

Source	Total Fired Hrs	NOx Max Emission Rate	CO Max Emission Rate	VOC Max Emission Rate	PM10 Max Emission Rate	NOx total	CO total	VOC total	PM10 total
		lb/hr	lb/hr	lb/hr	lb/hr	tons	tons	tons	tons
2005 7H Permit Application both units:	509	N/A	N/A	N/A	N/A	43	14	1.1	3
2005 7H Permit Application one unit:	255	587	777	13	10	21	7	0.5	1.3
2014 7HA.01 one unit:	247	169	412	13	7.5	11	6.7	0.45	0.9
Net Change	-8	-418	-365	0	-3	-10	-0.2	-0.1	-0.4

Notes:
1. In 2005, only one turbine was to be commissioned at a time, therefore hourly emission rates for both units do not apply.

DESCRIPTION OF STEPS:

GT Initial Start-up
GT Sync & Load
HRSG Operation on Steam Bypass
GT Loading up to Base on PPM with Primary Fuel
DLN Tuning
Integrated Tuning and Performance Test
ST Initial Start-up
ST Sync & Load
CC Operation Tuning
CC Performance tests (gaseous, noise emissions, output & HR)
Special tests
Commissioning Ends

Startup/Shutdown Emissions

	NOx (lb)	CO (lb)	VOC (lb)	Total PM (lb)	SO2 (lb)	Duration (min)	MMBtu (LHV)	SCF	NOx (lb/hr)	CO (lb/hr)
Cold Start	307	188	15.6	5.6	0.76	45	941	1,060,535	313	218
Warm Start	179	164	14	3.8	0.48	30	590	664,853	189	196
Hot Start	59	144	13	3.1	0.33	25	414	467,012	71	177
Shutdown	4	32	15	1.5	0.05	10	58	65,225	19	37
CSU+SD	NA	NA	NA	NA	NA	55	NA	NA	NA	NA
WSU+SD	NA	NA	NA	NA	NA	40	NA	NA	NA	NA
HSU+SD	NA	NA	NA	NA	NA	35	NA	NA	NA	NA

Projected Actual Emissions minus Baseline Actual Emissions

Pollutant	Monthly permit limit (lbs)	Monthly projected emissions (lbs)	Projected actual emissions (PAE)[a] Baseload (tpy)	Projected actual emissions (PAE)[a] Cycling (tpy)	Unused capacity emissions[b] (tpy)	Baseline actual emissions (BAE)[c] (tpy)	Net increase Baseload (tpy)	Net increase Cycling (tpy)	PSD Significant Emission Rate	PSD Trigger?
NOx	*N/A*	9,984	79.1	59.9	21.9	24.8	32.4	13.2	*40*	**N**
PM_{10}	*5,580*	3,120	30.6	18.7	12.8	14.9	2.9	-9.0	*10*	**N**
CO	*9,728*	8,960	48.9	53.8	7.5	3.6	37.8	42.6	*100*	**N**
SO_2	*1,362*	743	7.5	4.5	3.1	3.6	0.7	-2.3	*40*	**N**

a. Basis for Post-Project Projected Actual Emissions (PAE)

1. These projections are based on emission estimates for the 7HA.01 turbine, and the following operating scenarios:

	# events per month (cycling scenario)	**Annual baseload scenario**	**Annual cycling scenario**
Cold Start (#/year)	4	12	48
Warm Start (#/year)	0	12	0
Hot Start (#/year)	20	0	240
Shutdown (#/year)	24	24	288
Steady State (hours/year)	400	8141	4800
SU/SD (hours/month)	15.33		

2. IEEC anticipates based on market uncertainty that the facility may be required to operate as either a baseload or cycling plant; emissions have been calculated for each scenario.
3. All assumptions are subject to change as a result of actual market conditions, equipment performance and power sales opportunities.

b. Basis for Unused Capacity Emissions

1. Actual operations during the baseline analysis period (2010-2014) were limited by market conditions (low demand).

2. Baseline Actual Emissions are factored up from actual baseline capacity to the potential capacity factor of Unit 2 (capacity factor that Unit 2 could have accomodated) during the same period.

c. Basis for Baseline Actual Emissions (BAE)

1. Baseline emissions are based on the highest consecutive 24-month period over the last five years.

Baseline Actual Emissions Period	Natural Gas Unit 2 (mmscf)	Quarterly Emissions NOx (lbs)	Quarterly Emissions PM_{10} (lbs)	Quarterly Emissions CO (lbs)	Quarterly Emissions SO_2 (lbs)	Annual average, 24-month rolling NOx (tpy)	Annual average, 24-month rolling PM_{10} (tpy)	Annual average, 24-month rolling CO (tpy)	Annual average, 24-month rolling SO_2 (tpy)
2010 Q3	3,049	15,995	8,934		2,165				
2010 Q4	3,569	21,245	10,457	2,004	2,534				
2011 Q1	3,286	17,352	9,629		2,333				
2011 Q2	7	821	20	1,302	5				
2011 Q3	2,678	13,226	7,845		1,901				
2011 Q4	2,572	12,475	7,536	2,310	1,826				
2012 Q1	4,043	16,003	11,845		2,870				
2012 Q2	356	2,056	1,042	2,117	253	24.8	14.3	1.9	3.5
2012 Q3	3,824	14,308	11,206		2,715	24.4	14.9		3.6
2012 Q4	2,133	9,340	6,251	1,438	1,515	21.4	13.8	1.8	3.4
2013 Q1	1,451	7,000	4,252		1,030	18.8	12.5		3.0
2013 Q2	846	4,016	2,480	5,663	601	19.6	13.1	2.9	3.2
2013 Q3	2,874	15,446	8,421		2,041	20.2	13.3		3.2
2013 Q4	519	3,647	1,521	2,664	369	18.0	11.8	3.0	2.8
2014 Q1	1,074	6,333	3,148		763	15.5	9.6		2.3
2014 Q2	196	1,878	574	4,692	139	15.5	9.5	3.6	2.3

Notes:
1. Natural gas usage data from CEMS meter readings.
2. NOx data from Annual Permit Emissions Program (APEP) reporting.
3. CO data from Data Acquisition System (DAS); only available for six month periods, not quarterly.
4. PM_{10} and SO_2 emissions calculated based on natural gas usage, using permitted emission factors.
5. Unit 2 commissioning was completed in the second quarter of 2010; thus normal operations started in the third quarter, and only four years of historical data are available.

CYCLING SCENARIO

Turbine Operation	January	Feb	March	April	May	June
Cold starts	4	4	4	4	4	4
Warm starts	0	0	0	0	0	0
Hot starts	20	20	20	20	20	20
Shutdowns	24	24	24	24	24	24
Steady-state	400	400	400	400	400	400

CYCLING SCENARIO

Turbine Operation	July	Aug	Sept	Oct	Nov	Dec	**TOTAL**
Cold starts	4	4	4	4	4	4	**48**
Warm starts	0	0	0	0	0	0	**0**
Hot starts	20	20	20	20	20	20	**240**
Shutdowns	24	24	24	24	24	24	**288**
Steady-state	400	400	400	400	400	400	**4800**

Operating Scenarios	**Baseload Scenario**	**Cycling Scenario**
Startups	1 cold and 1 warm startup per month, all 12 months	Cold start every Monday, warm start every weekday, and shutdown over the weekend.
Steady-State	Annually 8,760 hours minus 25 days of maintenance outage minus startup/shutdown time	Weekday operations only, assuming 20 hours per day, 20 days per month.

DERIVATION OF UNUSED CAPACITY EMISSIONS FROM PRE-PROJECT BASELINE ACTUAL EMISSIONS (BAE) AND BASELINE CAPACITY FACTORS

	Unit 2			
	NO_X	**PM_{10}**	**CO**	**SO_X**
Baseline Period	2010 Q3 - 2012 Q2	2010 Q4 - 2012 Q3	2012 Q3 - 2014 Q2	2010 Q4 - 2012 Q3
Baseline Actual Emissions (ton)	24.79	14.90	3.61	3.61
Baseline Actual Capacity Factor	47%	48%	30%	48%
Potential Capacity Factor during Baseline Period	88%	90%	92%	90%
Emissions @ Full Capacity (ton)	46.67	27.70	11.12	6.71
Unused Capacity Emissions (ton)	21.88	12.81	7.50	3.10

Notes and Assumptions:

1. Actual operations during the baseline analysis period (2010-2014) were limited by market conditions (low demand).
2. Actual Capacity Factor is how much the unit actually ran in that period.
3. Potential Capacity Factor is the capacity that the Unit 2 turbine could have operated at if there had been sufficient market demand.
4. Emissions at Capacity are based on Baseline Actual Emissions factored up from actual baseline capacity to the Potential Capacity Factor in the same time period.
5. Excluded emissions = Emissions at Capacity - Actual Emissions

ANNUAL GENERATION AND CAPACITY FACTORS DURING BASELINE ANALYSIS PERIOD

	Actual Capacity Factor	**Potential Capacity Factor**
Baseline Emissions Period	**Unit 2**	**Unit 2**
2010 Q3 - 2012 Q2 (NOx)	47%	88%
2010 Q4 - 2012 Q3 (PM_{10} and SOx)	48%	90%
2012 Q3 - 2014 Q2 (CO)	30%	92%

Source: IEEC data.

SCAQMD

Potential Emissions minus Baseline Actual Emissions

Pollutant	**NOx**	**PM**	**CO**	**SO_2**	**VOC**
Emission Increases (lb/day)	741.8	180.0	453.1	43.3	91.2
Emission Decreases (lb/day)	103.6	63.3	24.2	15.3	38.7
Net increase (lb/day)	638.2	116.7	428.9	28.0	52.5

Notes:

1. Emission increase calculated per Rule 1306(b), based on one cold start per day and the remainder of the day at steady-state for the 7HA.01.

2. Emission decreases calculated based on Rule 1306(c), using the baseline actual emissions for 7H Unit 2 over the last 24 months (July 2012 - June 2014). Annual emissions were divided by the number of operating days in that period for a daily average. Based on the number of operating days in each year, a usage factor of 0.5 was applied.

SCAQMD Baseline Data - Most recent 24 months

UNIT 2 - pounds	**NOx**	**PM**	**CO**	**SO_2**	**VOC**	**# Days**
July - December 2012	23,648.0	17,456.1	1,438.0	4,230.0	10,664.3	134
Jan - June 2013	11,015.7	6,731.9	5,663.0	1,631.3	4,112.7	58
July - Dec 2013	19,092.4	9,942.6	2,664.0	2,409.3	6,074.1	76
January - June 2014	8,210.5	3,721.8	4,692.2	901.9	2,273.7	31
Daily Average Emissions (lb/day)	207.2	126.6	48.4	30.7	77.3	299
Rule 1306(c)(3) Usage factor applied (lb/day)	**103.6**	**63.3**	**24.2**	**15.3**	**38.7**	-

CEC

Potential Emissions minus Baseline Actual Emissions

Pollutant	NOx	PM	CO	SO_2	VOC
Potential to Emit (tpy)[1]	79.5	33.5	58.4	8.2	22.6
Baseline actual emissions (tpy)[2]	15.5	9.4	3.6	2.3	5.8
Net increase (tpy)	64.0	24.0	54.8	5.9	16.8

Notes:

1. Potential to Emit (PTE) is equal to the annual permit limit, based on annual RTCs for NO_X (permit condition I296.1); all other pollutants, annual permit limit based on monthly SCAQMD permit limit times 12 months/year (permit condition A63.1).

2. Baseline actual emissions are the average of the last two years of available data (July 2012 - June 2014).

Baseline - Most recent 24 months

UNIT 2 - tons per year	NOx	PM	CO	SO2	VOC
July - December 2012	11.8	8.7	0.7	2.1	5.3
2013	15.1	8.3	4.2	2.0	5.1
January - June 2014	4.1	1.9	2.3	0.5	1.1
AVERAGE (tons per year)	**15.5**	**9.4**	**3.6**	**2.3**	**5.8**

Potential to Emit (PTE) Comparisons

Operation	Turbine	NOx	PM	CO	SO2	VOC
Steady-State (lb/hr)	7HA.01	18.7	7.5	11.4	1.83	3.3
	7H	18.8	7.5	17.2	1.83	6.6
Cold Start (lb/event)	7HA.01	307	5.60	188	0.76	16
	7H	803	45	2000	10.98	48
Warm Start (lb/event)	7HA.01	179	3.80	164	0.48	14
	7H	-	-	-	-	-
Hot Start (lb/event)	7HA.01	59	3.10	144	0.33	13
	7H	408	7.5	800	1.83	16
Shutdown (lb/event)	7HA.01	4	1.50	32	0.05	15
	7H	-	-	-	-	-

Notes:

1. All emissions represent the potential emissions of the turbine, without accounting for any limits imposed by permits (e.g. what the turbine is capable of).

2. 7H emissions are from the "Staff Analysis of Proposed Modifications…" (CEC, June 2005), with the exception of updated PM emissions (2006 SCAQMD permit modification) and CO startup emissions (2009 IEEC License Amendment).

Facility-Wide Emissions
Potential to Emit from all Sources
PM2.5 Calculated for comparison to major source threshold of SCAQMD Rule 1325 (major = 100 tpy)

Source	Potential to Emit (tpy)					
	NOx	**PM10**	**PM2.5**	**CO**	**SO2**	**VOC**
Unit 1	79.5	33.5	33.5	58.4	8.2	22.6
Unit 2	79.5	33.5	33.5	58.4	8.2	22.6
Aux boiler	0.4	1.3	1.3	6.7	0.1	0.8
Cooling towers	-	15.4	0.02	-	-	-
Emergency Generator Engines	2.1	0.0	0.0	0.3	0.0	0.0
Firepump Engine	0.2	0.0	0.0	0.0	0.0	0.0
TOTAL (tpy)	**161.4**	**83.7**	**68.3**	**123.7**	**16.5**	**46.0**

Notes:
1. Turbines and Aux Boiler - NOx PTE based on RTCs during normal year (from Appendix A.1 to 2005 IEEC Amendment Application)
2. Turbines and Aux Boiler - PM, CO, SO2, and VOC PTE based on permit limits
3. Cooling tower emissions based on 8,760 hrs/year
4. Emergency engines and firepump emissions based on 50 hrs/year
5. $PM_{2.5}$ from cooling towers is assumed to be 0.16% of PM

based on SCAQMD "Guidelines for Calculating Emissions from Cooling Towers" and "Calculating Realistic PM10 Emissions from Cooling Towers", Joel Reisman and Gordon Frisbie, Abstract No. 216

SCAQMD "Guidelines for Calculating Emissions from Cooling Towers"

TDS	7800	mg/L	
Drift rate	0.0005	%	
density of water	8.34	lb/gal	
180,000		gallons per minute, both cooling towers	*Reference: 2005*
94,608,000,000		gallons per year	*IEEC Amendment*
94,608		MMgal/yr	

EF (lb PM / MMgal) = TDS * (drift rate in %) / 100 * density of water

EF =	0.32526	lb PM / MMgal
PM emissions	30772.2	lb/yr
PM emissions	15.4	ton/yr

"Calculating Realistic PM10 Emissions from Cooling Towers", Joel Reisman and Gordon Frisbie, Abstract No. 216

Cooling Tower PM

Droplet Diameter (um)	Solid Particle Diameter (um)	EPRI % mass smaller (%)		
10	1.52	0.00		
20	3.05	0.20	0.16%	PM2.5
30	4.57	0.23		
40	6.10	0.51		
50	7.62	1.82		
60	9.15	5.70		
70	10.67	21.35	20.00%	PM10
90	13.72	49.81		
110	16.77	70.51		
130	19.82	82.02		
150	22.87	88.01		
180	27.45	91.03		
210	32.02	92.47		
240	36.60	94.09		
270	41.17	94.69		
300	45.75	96.29		
350	53.37	97.01		
400	60.99	98.34		
450	68.62	99.07		
500	76.24	99.07		
600	91.49	100.00		

density of water	1	g/cm3	
density of particle	2.2	g/cm3	(density of sodium chloride)

Reference available at:

http://yosemite.epa.gov/R9/air/EPSS.NSF/735056a63c1390e08825657e0075d180/44841bd36885b15e882579f80062a144/$FILE/Cooling%20Tower%20Emission%20Calculations%20update.pdf

Toxic Air Contaminant Emissions for SCAQMD Rule 1401

Operating Parameters

Operation Mode	Maximum Annual operation (hr/yr)	Average Annual operation (hr/yr)	Max heating rate HHV (MMBtu/hr)	Maximum Annual Heating Value (MMBtu/yr)	Average Annual Heating Value (MMBtu/yr)
Normal Operations	8760	8160	2575.6	22,562,256	21,016,896

Notes:
1. Maximum annual operations based on continuous baseload operation.
2. Average annual operation based on the baseload projected operating scenario, including both steady-state and startup/shutdown hours.
3. Max heating rate based on the highest case, the cold ambient, baseload scenario.

Pollutant	CAS	Emission Factor (lb/MMBtu)	Emission factor source[1]	Maximum Hourly Emission Rate (lb/hr)	Maximum Annual Emission Rate (lb/yr)	Average Annual Emission Rate (lb/yr)
Ammonia[2,3]	7664417	5 ppm	PTO	17.3	151,548.0	141,168.0
Acetaldehyde	75070	1.76E-04	AP-42 w CO catalyst	4.53E-01	3,971.0	3,699.0
Acrolein	107028	3.62E-06	AP-42 w CO catalyst	9.32E-03	81.7	76.1
Benzene	71432	3.26E-06	AP-42 w CO catalyst	8.40E-03	73.6	68.5
1,3-Butadiene	106990	4.30E-07	AP-42	1.11E-03	9.7	9.0
Ethylbenzene	100414	3.20E-05	AP-42	8.24E-02	722.0	672.5
Formaldehyde	50000	3.60E-04	AP-42 w CO catalyst	9.27E-01	8,122.4	7,566.1
Naphthalene	91203	1.27E-06	AP-42	3.27E-03	28.7	26.7
PAHs	1151	2.23E-06	AP-42	5.74E-03	50.3	46.9
Propylene Oxide	75569	2.86E-05	AP-42	7.37E-02	645.3	601.1
Toluene	108883	1.34E-04	AP-42	3.45E-01	3,023.3	2,816.3
Xylenes	1330207	6.38E-05	AP-42	1.64E-01	1,439.5	1,340.9
				Total HAPs (lb/yr)	**18,167.4**	**16,923.0**
				Total HAPs (tons/yr)	**9.1**	**8.5**

Notes:

1. Emission factors obtained from AP-42 Section 3.1, Table 3.1-3 for a natural gas-fired combustion turbine and the associated Background Document, Table 3.4-1, for controlled emissions with CO catalyst.
2. Ammonia emission rate based on an exhaust NH_3 limit of 5 ppmv @ 15% O_2 in accordance with SCAQMD permit limits.
3. Ammonia is not a federal (CAA 112) HAP, and is not included in the total HAPs for the facility.

APPENDIX C
BACT ANALYSIS

BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

FOR THE
INLAND EMPIRE ENERGY CENTER UNIT 2
TURBINE REPLACEMENT PROJECT
MENIFEE, RIVERSIDE COUNTY, CALIFORNIA

For submittal to:

South Coast Air Quality Management District
California Energy Commission

Prepared by:

URS

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September 30, 2014

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ACRONYM LIST

BAAQMD	Bay Area Air Quality Management District
BACT	Best Available Control Technology
CAAQS	California Ambient Air Quality Standards
CARB	California Air Resource Board
CCGT	combined cycle gas turbine
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
CT	combustion turbine
CTG	combustion turbine generator
DLN	dry low-NO_X
DOE	Department of Energy
ESP	electrostatic precipitators
FGD	flue gas desulfurization
GCP	Good Combustion Practice
GE	General Electric Company
gr/scf	grains per standard cubic foot
H_2O	water
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
HRSG	heat recovery steam generator
Hz	Hertz
IEEC	Inland Empire Energy Center
LAER	Lowest Available Emission Rate
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal unit
lb/MWh	pounds per megawatt hour
MMBtu/hr	million British thermal units per hour
MW	megawatt
N_2	nitrogen
NAAQS	National Ambient Air Quality Standard
NG	natural gas
NGCC	natural gas combined cycle
NH_3	ammonia
NO	nitric oxide
NO_2	nitrogen dioxide

NO_X	oxides of nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
O_2	oxygen
PM	particulate matter
PM_{10}	particulate matter less than 10 microns in aerodynamic diameter
$PM_{2.5}$	particulate matter less than 2.5 microns in aerodynamic diameter
ppm	parts per million
ppmvd	parts per million by volume, dry basis
PSD	Prevention of Significant Deterioration
PUC	Public Utilities Commission
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
SCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
scf	standard cubic foot
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SO_3	sulfite
SO_X	sulfur oxides
STG	steam turbine generator
U.S. EPA	United States Environmental Protection Agency
VOC	volatile organic compounds

SECTION 1.0
INTRODUCTION

This document has been prepared to address the South Coast Air Quality Management District's (SCAQMD) requirements under Regulation XIII, New Source Review (NSR). The proposed Inland Empire Energy Center (IEEC) Unit 2 Turbine Replacement Project (Project) is exempt from modeling and offset requirements because it meets the Rule 1304(a)(1) exemption for functionally identical replacements. However, a Best Available Control Technology (BACT) analysis is still required under Regulation XIII. The Project is not subject to federal Prevention of Significant Deterioration (PSD) review. This BACT analysis applies to the replacement turbine.

IEEC consists of an 810-megawatt (MW) combined cycle power plant in the city of Menifee in Riverside County, California. IEEC plans to replace one of the existing General Electric Company (GE) 7H-technology gas turbines (GE S107H) with the latest generation in H technology (GE 7HA.01). At the time of installation, the S107H represented GE's most advanced technology, and now the 7H technology has evolved into the new 7HA.01 unit, which can provide the following benefits:

- Improved efficiency;
- Lower operation and maintenance costs; and
- Reduced water usage from an air-cooled gas turbine.

The proposed 7HA.01 combustion turbine (CT) unit will be a functionally equivalent model to the existing Unit 2 7H CT from flange to flange. The existing plant layout and balance of plant equipment, including stacks, heat recovery steam generator (HRSG) and associated emission control systems, and steam turbine generator (STG), will remain unchanged. Similarly, an existing auxiliary boiler, wet cooling tower system (total 16 cells), a diesel firewater pump, and two diesel emergency generators will remain unchanged.

The Project provides a unique opportunity for GE to install and demonstrate performance of its new evolutionary technology. GE is currently testing the 9HA (50 Hertz [Hz]) at its Greenville, South Carolina full-load validation facility. The 7HA.01 (60 Hz) turbine will receive the same full-load validation in Greenville, South Carolina in 2015, with a unit operating and in service at IEEC by 2016.

This BACT document is a component of IEEC's application for a revision to the existing Title V Operating Permit, and for a Permit to Construct. IEEC will not request changes to the emission limits or other conditions in the current Title V Operating Permit for the 7HA.01 replacement.

District Regulation XIII (NSR) "shall apply to the installation of a new source and to the modification of an existing source which may cause the issuance of any nonattainment air contaminant, any ODC [ozone depleting compound], or ammonia at any facility" (Rule 1301[b]). Based on this applicability threshold, the Project triggers review under Regulation XIII.

Because the 7HA.01 turbine is functionally identical to the existing 7H turbine, with no increase in maximum rating or potential to emit any air contaminant from Unit 2, the Project will be exempt from elements of nonattainment NSR per the SCAQMD exemption for replacements according to Rule 1304(a)(1). This provision exempts the Project from performing modeling or providing additional offsets under NSR; Unit 2's potential emissions were fully offset when the IEEC was initially permitted. The Turbine Replacement Project is required to demonstrate that the 7HA.01 turbine meets all BACT requirements. This approach was discussed and agreed upon in an August 6, 2014, meeting with SCAQMD, IEEC, and URS Corporation.

The Turbine Replacement Project is not subject to United States Environmental Protection Agency's (U.S. EPA) PSD requirements, because PSD significant emission rates will not be exceeded based on the actual-to-projected-actual applicability test. No changes are required to the existing permit. IEEC is in the process of documenting the inapplicability of PSD review with U.S. EPA Region 9, and will comply with the applicable 5-year recordkeeping requirements associated with the actual-to-projected-actual methodology required by 40 Code of Federal Regulations (CFR) 52.21(r)(6)(iii).

This Project is subject to requirements of the California Environmental Quality Act (CEQA). The California Energy Commission (CEC) will be the lead agency for review under CEQA and will coordinate its independent air quality evaluations with the SCAQMD.

SECTION 2.0
PROJECT PURPOSE AND OBJECTIVE

IEEC currently serves the growing demand for power in the greater Inland Empire region, necessitated in part by the closure of the San Onofre Nuclear Generating Station, retirement of once-through cooling power plants in the region, and the significant ongoing growth of renewable generation resources.

The IEEC gas turbine replacement provides a unique opportunity for GE to install and demonstrate performance of its new evolutionary technology. Proving this technology would be of near-term benefit to the local air basin, and long-term benefit to areas elsewhere in the United States and globally where older power plants could be retrofitted with this more efficient technology.

SECTION 3.0
APPLICABLE REGULATIONS

The applicability of various regulatory requirements for air control technology review is a function of each regulated air pollutant's air quality attainment status, and whether facility-wide emissions exceed major source thresholds. SCAQMD considers the proposed new Unit 2 7HA.01 turbine to be a replacement rather than a modification under Regulation XIII, NSR. In effect, the replacement turbine is treated as a new emission unit for BACT applicability purposes.

Attainment status details for federal and state ambient air quality standards are summarized below and in the permit application. The Project is in the South Coast Air Basin (SCAB), which is currently designated nonattainment for the National Ambient Air Quality Standard (NAAQS) for particulate matter less than 2.5 microns in aerodynamic diameter ($PM_{2.5}$), and nonattainment with respect to the California Ambient Air Quality Standards (CAAQS) for nitrogen dioxide (NO_2) and both particulate matter less than 10 microns in aerodynamic diameter (PM_{10}) and $PM_{2.5}$. The SCAB is also nonattainment with respect to both the CAAQS and NAAQS for ozone.

Federal requirements pertaining to control of non-attainment and precursor pollutants, or Lowest Available Emission Rate (LAER), were promulgated by U.S. EPA under 40 CFR 51.165 (a). This regulation defines LAER as the emissions limit based on either: 1) the most stringent emission rate contained in a State Implementation Plan (SIP), unless the (source) demonstrates the rate is not achievable; or 2) the most stringent emissions limitation that is achieved in practice. The federal LAER does not consider the cost impacts of control unless cost is so great that a new source could not be built or operated with a particular control technology.

Federal nonattainment requirements are implemented by SCAQMD Rule 1303, which requires BACT to be applied to any major new source (i.e., resulting in a significant increase in emissions of any nonattainment air contaminant), any ozone-depleting compound, or ammonia (NH_3). Rule 1303 also states that if the source is located at a major facility, then the BACT determination "shall be at least as stringent as LAER as defined in the federal Clean Air Act Section 171(3) (42 U.S. Code Section 7501[3])."

According to Regulation XIII, SCAQMD's BACT requirements need to be met without considering economic, environmental and energy factors for emissions of any nonattainment pollutant, ozone-depleting compound, or NH_3 at a major polluting facility. IEEC is a major source for the pollutants oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOCs), and PM_{10}; a minor source for $PM_{2.5}$ and sulfur dioxide (SO_2), and also emits NH_3 from the selective catalytic reduction (SCR) control systems. Therefore, LAER must be met for all pollutants. Note that NO_X and VOC are defined as ozone precursors, and SO_2 and NH_3 are defined as PM_{10}/ $PM_{2.5}$ precursors. SCAQMD BACT applies to PM_{10} because ambient concentrations exceed the CAAQS, but they do not exceed NAAQS. CO is included in this analysis for a complete demonstration of BACT even though it is an attainment pollutant in the SCAB.

This BACT analysis was prepared according to the SCAQMD BACT Guidelines (SCAQMD, 2006a), and the U.S. EPA NSR Workshop Manual (USEPA, 1990).

BACT for the applicable pollutants was determined by first reviewing SCAQMD's LAER/ BACT Determinations, U.S. EPA's Reasonably Available Control Technology/BACT/LAER Clearinghouse (RBLC) (USEPA, 2014), California Air Resource Board's (CARB) BACT Clearinghouse (CARB, 2014), other air district BACT determinations, and recently permitted CEC projects.

SCAQMD nonattainment NSR (Rule 1302) defines BACT to be the most stringent emission limitation or control technique that:

- Has been achieved in practice for such category or class of source; or
- Is contained in any SIP approved by the U.S. EPA for such category or class of source. A specific limitation or control technique shall not apply if the owner of the proposed source demonstrates to the satisfaction of the Executive Officer or designee that such a limitation or control technique is not presently achievable; or
- Is any other emission limitation or control technique, found by the Executive Officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures as listed in the Air Quality Management Plan or rules adopted by the District Governing Board.

The BACT review of the IEEC 7HA.01 turbine is performed for the following criteria pollutants: NO_X, CO, VOC, PM_{10}/$PM_{2.5}$, SO_2, and NH_3.

SECTION 4.0
BACT REVIEW PROCESS

The "top-down" methodology for determining BACT involves the identification of all applicable control technologies according to control effectiveness.[1] Evaluation begins with the "top," or most stringent, control alternative. If the most stringent option is shown to be technically or economically infeasible, or if environmental impacts are severe enough to preclude its use, then it is eliminated from consideration, and the next most stringent control technology is similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by technical or economic considerations, energy impacts, or environmental impacts. The top control alternative that is not eliminated in this process becomes the proposed BACT basis.

This top-down BACT analysis process can be considered to contain five basic steps, described below (from the U.S. EPA's Draft NSR Workshop Manual, 1990):

- **Step 1.** Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation.

- **Step 2.** Eliminate all technically infeasible control technologies.

- **Step 3.** Rank remaining control technologies by control effectiveness and tabulate a control hierarchy.

- **Step 4.** Evaluate most effective controls and document results.

- **Step 5.** Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

These BACT steps are the same for major nonattainment pollutant sources except in Step 5, where economic, environmental, and energy considerations are excluded. Note, however, that economics is not entirely excluded. "LAER is not considered achievable if the cost of control is so great that a major source could not be built or operated." (U.S. EPA, 1990; NSR Workshop Manual – Prevention of Significant Deterioration and Nonattainment Area Permitting, p. G.3). Formal use of every step is not always necessary. However, the U.S. EPA has consistently interpreted the statutory and regulatory BACT and LAER definitions as containing two core requirements, which U.S. EPA believes must be met by any BACT/LAER determination, irrespective of whether it is conducted in a "top-down" manner. First, the BACT/LAER analysis

[1] In a December 1, 1987, memorandum from the U.S. EPA Assistant Administrator for Air and Radiation, the agency provided guidance on the "top-down" methodology for determining BACT. Although not specifically detailed in the SCAQMD BACT Guidelines, this methodology is used in practice by the District in their BACT determinations, and will be used in this analysis.

must include consideration of the most stringent available technologies, i.e., those that provide the “maximum degree of emissions reduction.”

Second, any BACT decision to require a lesser degree of emissions reduction must be justified by an objective analysis of “energy, environmental, and economic impacts” contained in the record of the permit decisions.

Additionally, the minimum control efficiency to be considered in a BACT/LAER analysis must result in an emission rate no less stringent than the applicable New Source Performance Standard (NSPS) emission rate, if any NSPS standard for that pollutant is applicable to the source.

This BACT analysis was conducted in a manner consistent with this stepwise approach. Control options for potential reductions in emissions were identified for each source. These options were identified by researching the numerous BACT and LAER databases, drawing upon previous environmental permitting experience for similar units and surveying available literature. Available control technologies that are judged to be technically feasible may be further evaluated based on an analysis of economic, environmental, and energy impacts. This additional analysis is applicable only to $PM_{2.5}$ and SO_2 because IEEC is a minor source of these pollutants.

Assessing the technical feasibility of emission control alternatives is discussed in SCAQMD’s BACT Guidelines. Using terminology from these guidelines, if a control technology has been “Achieved in Practice” for the type of emission unit under review, then it would normally be considered technically feasible. For an undemonstrated technology, “availability” and “applicability” determine technical feasibility. An available technology is one that is commercially available, meaning that it has advanced through the following steps:

- Concept stage;
- Research and patenting;
- Bench-scale or laboratory testing;
- Pilot-scale testing;
- Licensing and commercial demonstration; and
- Commercial sales.

The Turbine Replacement Project only entails removing the existing turbine in Unit 2 and replacing it with a functionally equivalent turbine. For this reason, this BACT analysis focuses on alternative technologies that potentially could be implemented within the constraints of an equipment replacement project, as opposed to an entirely new facility.

SECTION 5.0
PROJECT SOURCES SUBJECT TO BACT ANALYSIS

The emission sources associated with the IEEC Turbine Replacement Project will include only one 7HA.01 turbine.

The proposed 7HA.01 CT replacement unit will be a functionally equivalent model to the existing Unit 2 7H CT from flange to flange. The existing plant layout and balance of plant equipment, including stacks, HRSG and associated emission control systems, and STG, will remain unchanged. Similarly, the existing auxiliary boiler, wet cooling tower system (total 16 cells), a diesel firewater pump, and two diesel emergency generators, will remain unchanged.

The 7HA.01 replacement CT will be fired exclusively on natural gas, and will be equipped with dry low-NO_X (DLN) burners and SCR for the control of NO_X emissions, and an oxidation catalyst for control of CO and VOC emissions. Due to the single-shaft configuration, the new turbine will operate in combined-cycle mode only, and can range from a baseload operating profile to a load following or cycling profile.

Table 5-1 presents the proposed control technologies and proposed emission limit for the 7HA.01 turbine for each regulated pollutant.

TABLE 5-1
PROPOSED BACT FOR TURBINE REPLACEMENT PROJECT

Pollutant	Technology	Proposed Emission Limit
NO_X	DLN burners and SCR	2.0 ppmvd NO_X at 15 percent O_2, 1-hour average
CO	GCP, oxidation catalyst	2.0 ppmvd CO at 15 percent O_2, 1-hour average
PM	GCP, pipeline quality natural gas	11 lb/hr or 0.01 gr/scf natural gas
$PM_{10}/PM_{2.5}$	GCP, pipeline quality natural gas	7.5 lb/hr
SO_X	Pipeline quality natural gas	0.9 lb/MWh ≤ 0.25 grain H_2S/100 scf in natural gas
VOC	Oxidation catalyst	1.0 ppmvd at 15 percent O_2, 1-hour average
NH_3	SCR	5 ppmvd NH_3 slip, 3-hour average
All pollutants during Startup/ Shutdown	GE “rapid response” technology, limit total startup and shutdown emissions, apply emission controls as much as feasible during the startup and shutdown events.	Daily startup and shutdown time shall not exceed 4 hours per turbine hot start, or 6 hours per day per turbine for a cold startup; monthly startup and shutdown time shall not exceed 31 hours per unit.

Notes:

BACT = Best Available Control Technology
CO = carbon monoxide
DLN = dry low-NO_X
GCP = good combustion practice
GE = General Electric Company
gr/scf = grains per standard cubic foot
H_2S = hydrogen sulfide
lb/hr = pounds per hour
lb/MWh = pound per megawatt-hour
NH_3 = ammonia
NO_X = oxides of nitrogen
O_2 = oxygen
PM = particulate matter
PM_{10} = particulate matter less than 10 microns in aerodynamic diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in aerodynamic diameter
ppmvd = parts per million by volume, dry basis
scf = standard cubic foot
SCR = selective catalytic reduction
SO_X = sulfur oxides
VOC = volatile organic compound

SECTION 6.0
CONSIDERATION OF ALTERNATIVE TECHNOLOGY

This section addresses guidance relating to the need for consideration of alternative technologies or the use of "clean fuels" for the proposed Project, as part of the criteria pollutant analysis.

The first step in a BACT determination process is to identify all available control technologies that could potentially be used to minimize the emissions of the source and pollutant under evaluation. The most common control technologies considered in a BACT analysis are the use of clean fuels, add-on control measures and inherent process characteristics that minimize generation of pollutants, in addition to process or work practice modifications to improve the emissions performance of a proposed project. These types of process modifications/measures, when applicable, are properly considered in a BACT analysis.

In contrast, consideration of alternatives that would involve completely "redefining the design" of the proposed process are not required to be considered (1990 Draft NSR Workshop Manual, Section IV.A.3). Alternative generating processes, such as solar or wind, generation plants, or use of "clean fuels," such as hydrogen or biomass, represent a completely different family of power generation plant designs from natural gas combined cycle (NGCC). Although hydrogen-fired or biomass-fired generation facilities may have certain similar components, such as cooling towers and steam-driven turbine generators, the technical basis for these plants differs markedly from that of a NGCC facility. In addition, natural gas is a clean fuel, and in some cases may be cleaner than combustion of hydrogen or biomass.

Use of solar or wind generation would not meet one of the primary objectives of the project; specifically, complementing renewable energy such as solar and wind, and therefore should not be considered as an alternative technology. The use of hydrogen-fired or biomass-fired generation would redefine the design of the project, and therefore should not be considered as a "clean fuel" alternative technology. The use of these alternative generation technologies would not fulfill the business and project purposes, and would constitute a substantial redesign of the source.

SECTION 7.0
CT CRITERIA POLLUTANT BACT ANALYSIS

The following BACT analysis evaluates control technologies applicable to each of the criteria pollutants and NH_3 that would be emitted from the IEEC 7HA.01 turbine to determine appropriate BACT emission limits. This BACT analysis is based on the current state of NGCC technology and technical feasibility.

The following is the BACT analysis for the proposed replacement CT. IEEC will use GE's new 7HA.01 turbine design to replace the existing 7H CT, integrating it with the existing Unit 2 HRSG and STG.

The CT will use DLN combustors to control exhaust gas NO_X. The CT will also be air cooled for performance enhancement capabilities.

The CT will exhaust to an existing HRSG, currently equipped with a SCR system for NO_X control and an oxidation catalyst for CO control. An existing Continuous Emissions Monitoring System will continue to measure CT exhaust stack gases, including NO_X, CO, oxygen (O_2), and NH_3.

7.1 NITROGEN OXIDES BACT ANALYSIS FOR THE 7HA.01 CT

The criteria pollutant NO_X is primarily formed in combustion processes via the reaction of elemental nitrogen (N_2) and O_2 in the combustion flames (thermal NO_X), and the oxidation of minor amounts of N_2 compounds contained in the natural gas fuel (fuel NO_X). The rate of formation of thermal NO_X in a CT is a function of residence time, O_2 radicals, and peak flame temperature.

Front-end combustion process NO_X control techniques are aimed at controlling one or more of these variables during combustion. Examples include DLN combustors and diluent injection (steam or water).

Higher peak-flame temperature during combustion may increase thermodynamic efficiency in a CT, but it also increases the formation of thermal NO_X. The injection of an inert diluent such as atomized water or steam into the fuel gas line or the high-temperature region of a CT combustor flame serves to inhibit thermal NO_X formation by reducing the peak flame temperature while also adding mass to improve CT efficiency.

SCR is a technology that achieves post-combustion reduction of NO_X from flue gas in a catalytic reactor. The SCR process involves the injection of NH_3 into the exhaust gas stream upstream of a specialized catalyst module to promote the conversion of NO_X and NH_3 to N_2 and water (H_2O).

Modern combined-cycle CT units using natural gas are typically equipped with DLN combustors in the CT. DLN combustors use multistage premix combustors where the air and fuel are mixed at a lean (high O_2) fuel-to-air ratio. The excess air in the lean mixture acts as a heat sink, which lowers peak combustion temperatures and also ensures a more homogeneous mixture, both resulting in greatly reduced NO_X formation rates. Modern DLN combustors typically produce emission levels in the range of 9 to 25 parts per million by volume, dry basis (ppmvd) NO_X at the combustion exhaust. NO_X emissions are then reduced approximately 90 percent with the SCR.

IEEC will continue to use DLN combustors and SCR to control NO_X emissions from the CT. This combination of control processes is achieved in practice and will achieve the existing permitted NO_X emission rate of 2.0 ppmvd at 15 percent O_2, based on a 1-hour average, and qualifies as BACT when compared to other recent BACT determinations for similar combined cycle gas turbine applications.

7.1.1 Identify Control Technologies

The following NO_X control technologies were evaluated for the proposed turbine replacement:

- Combustion process controls:
  - DLN burners for CT
  - Diluent injection
  - Catalytic combustors

- Post-combustion controls:
  - $SCONO_X$™
  - Selective non-catalytic reduction (SNCR)
  - SCR

7.1.2 Evaluate Technical Feasibilities

Dry Low-NO_X Combustor

DLN combustor technology has been successfully demonstrated to reduce thermal NO_X formation from natural-gas CTs. This is done by designing the combustors to control both the stoichiometry and temperature of combustion by tuning the fuel and air locally within each individual combustor's flame envelope. Combustor design includes features that regulate the aerodynamic distribution and mixing of the fuel and air. A lean, pre-mixed combustor design mixes the fuel and air prior to combustion. This results in a homogeneous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_X emissions. A lean fuel-to-air ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower the combustion temperature, which in turn lowers thermal NO_X formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment. DLN combustors typically produce emissions in the range of 9 to 25 parts per million (ppm) $NO_{X.}$ IEEC will continue to use DLN combustors for the replacement 7HA.01 CT.

Diluent Injection

Higher peak-flame temperature during combustion may increase thermodynamic efficiency, but it also increases the formation of thermal NO_X. The injection of an inert diluent such as atomized water or steam into the high-temperature region of a combustor flame serves to inhibit thermal NO_X formation by reducing the peak-flame temperature. The injected water or steam exits the turbine as part of the exhaust. Water and steam injection have been in use on gas-fired CTs in all size ranges for many years. However, the use of diluent injection has a slightly lower thermal efficiency compared to DLN combustors.

Catalytic Combustors

Catalytic combustors use a catalytic reactor bed mounted in the combustor to burn a very lean fuel-air mixture. This technology has been commercially demonstrated under the trade name Xonon™ in a 1.5 MW natural-gas–fired CT in Santa Clara, California. No turbine vendor, other than Kawasaki, has indicated the commercial availability of catalytic combustion systems at the present time, and the largest size is 18 MW. The technology is not commercially available for the turbine proposed by IEEC and other similarly sized CTs; therefore, it is not considered further.

$SCONO_X$™ or EM_X™

The $SCONO_X$™ system, also known as EM_X™, is an add-on control device that reduces emissions of multiple pollutants. $SCONO_X$™ uses a single catalyst for the reduction of CO, VOC, and NO_X, which are converted to carbon dioxide (CO_2), H_2O, and N_2.

The catalyst is a monolithic design, made from a ceramic substrate with both a proprietary platinum-based oxidation catalyst and a potassium carbonate adsorption coating. The catalyst simultaneously oxidizes nitric oxide (NO) to NO_2, while NO_2 is adsorbed onto the catalyst surface where it is chemically converted to and stored as potassium nitrates and nitrites. The $SCONO_X$™ potassium carbonate layer has a limited adsorption capability and requires regeneration approximately every 12 to 15 minutes in normal service. Each regeneration cycle requires approximately 3 to 5 minutes. At any point in time, approximately 20 percent of the compartments in a $SCONO_X$™ system would be in regeneration mode, and the remaining 80 percent of the compartments would be in oxidation/absorption mode.

All installations of the technology have been on small natural gas facilities, and all of those facilities have experienced performance issues. The fact that $SCONO_X$™ has not been applied to large-scale natural gas CTs like the 7H creates concerns regarding the feasibility.

In a recent BACT analysis performed by SCAQMD for the Redondo Beach Energy Project, SCAQMD engineers did carry forward $SCONO_X$™ as a potential control for its turbines; however, the turbine proposed for this project is considerably larger (405 MW vs. 132 MW on the Redondo Beach Energy Project), and it remains true that $SCONO_X$™ has not been demonstrated in practice on a turbine similar to that proposed by IEEC. For the above reasons, $SCONO_X$™ is considered technically infeasible to meet the 2 ppm NO_X emission level that can be achieved with SCR.

Selective Non-Catalytic Reduction

SNCR is a post-combustion NO_X control technology in which a reagent (NH_3 or urea) is injected into the exhaust gases to react chemically with NO_X to form elemental N_2 and H_2O without the use of a catalyst. The success of this process in reducing NO_X emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas, which must occur in a narrow flue gas temperature zone (typically from 1,700 to 2,000 degrees Fahrenheit).

The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to NO_X. Below the lower end of the temperature range, the reagent will not react with the NO_X, resulting in very high NH_3 slip concentrations (NH_3 discharge from the stack).

This technology requires a flue gas temperature that is significantly higher than the exhaust temperature from a NGCC; therefore, SNCR is not technically feasible for this unit.

Selective Catalytic Reduction

SCR is a technology that achieves post-combustion reduction of NO_X from flue gas in a catalytic reactor. The SCR process involves the injection of NH_3 into the exhaust gas stream upstream of a specialized catalyst module to promote the conversion of NO_X to molecular N_2. SCR is a common control technology for use on natural-gas–fired CTs.

In the SCR process, NH_3, usually diluted with air or steam, is injected through a grid system into the exhaust gas upstream of the catalyst bed. On the catalyst surface, the NH_3 reacts with NO_X to form molecular N_2 and H_2O. The basic reactions are:

- $4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$
- $8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$

IEEC will inject aqueous NH_3 into the stack gases upstream of a catalytic system that converts NO_X (NO and NO_2) and NH_3 to N_2 and H_2O, which is current practice on the existing 7H. The SCR system reduces NO_X emissions from the HRSG stack gases. The SCR system, in combination with the DLN combustors, will control NO_X emissions to 2 ppm.

Three of the technologies identified above—Catalytic Combustors, SNCR, and $SCONO_X$™—have been eliminated as technically infeasible.

7.1.3 Rank Control Technologies

Table 7-1 presents the individual and combined effectiveness of the control methods that were determined to be technically feasible. DLN combustors, combined with SCR, provide the most effective emissions controls (i.e., 2 ppmvd at 15 percent O_2 on a 1-hour basis). IEEC currently uses the combination of these two technologies, and would continue to do so with the 7HA.01 CT. This arrangement provides the most effective combination of control options that are available and feasible for the IEEC's proposed CT replacement.

TABLE 7-1
NO_X CONTROL TECHNOLOGIES RANKED BY CONTROL EFFECTIVENESS

NO_X Control Technology	Controlled Emission Rate (ppmvd at 15% O_2, 1-hour average)
SCR with DLN Combustors (lean premix)	2.0
SCR with Diluent injection	2.0 (however, loss of thermal efficiency)
Dry Low-NO_X Combustors (lean premix)	9-25
Diluent injection	25

Notes:
DLN = dry low-NO_X
NO_X = oxides of nitrogen
O_2 = oxygen
ppmvd = parts per million by volume, dry basis
SCR = selective catalytic reduction

Diluent injection would provide less NO_X control than DLN, and in combination with SCR would provide the same NO_X control, but at a loss of thermal efficiency; therefore, this control technology is ranked behind the selected technology.

7.1.4 Evaluate Control Options

The next step in a BACT analysis is to evaluate the feasible control technology. Based on the evaluation in the previous step, the control technologies selected are the most effective combination of control options that are available and feasible.

Table 7-2 shows the typical NO_X BACT and LAER determinations and control technologies for other recently permitted NGCC projects. These determinations were identified by reviewing SCAQMD's LAER/BACT Determinations, U.S. EPA's RBLC, CARB's BACT Clearinghouse, other air district BACT determinations, and recently permitted CEC projects.

As shown in Table 7-2, the BACT limitation for NO_X emissions from the IEEC 7HA.01 CT is as stringent as the BACT determinations for other recently permitted, similarly sized NGCC projects.

TABLE 7-2
NATURAL GAS COMBINED CYCLE NO_X BACT/LAER EMISSION LIMIT COMPARISON

Facility Name	Turbines	Facility Power Generation	BACT Emission Control	Permitted or Proposed Emission Limit (at 15 Percent O_2)	Status
Black Hills Energy/Cheyenne Prairie Generating Station (Black Hill Power, 2014)	1 GE natural-gas–fired CTGs, 95 MW from each CTG	132 MW	SCR	3.0 ppm (1-hour)	In construction
Sutter – Calpine (CEC, 2014)	2 Siemens Westinghouse 501FC natural-gas–fired CTGs with HRSG and duct firing, 170 MW from each CTG	540 MW	DLN burners, SCR	2.5 ppm (1-hour)	Operation from 2001
Elk Hills Power LLC (CEC, 2000a)	2 GE natural-gas–fired CTGs, Each CTG system will generate 166 MW plus 171 MW from the STG	500 MW	DLN burners, SCR or $SCONO_X$	2.5 ppm (1-hour)	Operation from 2003
High Desert Power Project (MDAQMD, 1999)	3 Siemens Westinghouse W501FD2s natural gas fired CTGs, 190 MW from each CTG	830 MW	DLN burners, SCR	2.5 ppm (1-hour)	Operation from 2003
Blythe Energy Project II (CEC, 2005)	2 Siemens SGT6-5000F natural-gas–fired CTGs, 1 steam turbine, 170 MW from each CTG	520 MW	DLN burners, SCR	2.0 ppm (3-hour)	Approved in 2005
Tracy Substation Expansion Project (U.S. EPA, 2014)	2 GE 7001FA+E natural-gas–fired CTGs	564 MW	SCR	2.0 ppm (3-hour)	Operation from 2008
Langley Gulch Power Plant (U.S. EPA, 2014)	1 Siemens SGT6-5000F natural-gas–fired CTGs	300 MW	DLN burners, SCR	2.0 ppm (3-hour)	Operation from 2012
Channel Energy Center, LLC (U.S. EPA, 2014)	3 Siemens SGT6-5000F (W501FD) natural-gas–fired CTGs	463 MW+	SCR	2.0 ppm (3-hour)	Operation from 2002
Deer Park Energy Center, LLC (U.S. EPA, 2014)	4 Siemens SGT6-5000F (W501FD) natural-gas–fired CTGs	830 MW	SCR	2.0 ppm (3-hour)	Operation from 2003

TABLE 7-2
NATURAL GAS COMBINED CYCLE NO_X BACT/LAER EMISSION LIMIT COMPARISON (CONTINUED)

Facility Name	Turbines	Facility Power Generation	BACT Emission Control	Permitted or Proposed Emission Limit (at 15 Percent O_2)	Status
ES Joslin Power Station; Calhoun Port Authority (Hill Country Environmental, 2012)	3 GE 7EA natural-gas–fired CTGs	887.5 MW	SCR	2.0 ppm (3-hour)	In permitting
Palomar Escondido – SDG&E (CEC, 2003)	2 GE 7FA natural-gas–fired CTGs, 1 STG, 165 MW from each CTG	570 MW	DLN burners, SCR	2.0 ppm (1-hour) and (3-hour) when duct firing or during transient hours	Operation from 2009
Garrison Energy Center, LLC/Calpine Corporation (DE DNREC, 2013)	1 GE 7FA natural-gas–fired CTG	309 MW	SCR	2.0 ppm	In construction
Patriot Power Generation Plant (Moxie Energy, 2014)	2 natural gas fired CTGs, 225-250 MW from each CTG	700 MW	SCR	2.0 ppm	In construction
Warren County Power Station (VA DEQ, 2010a, 2010b, 2014)	3 MHI M501GAC natural gas fired CTGs	1,300 MW	DLN burners, SCR	2.0 ppm (1-hour)	In construction
Gila Bend Power Generating Station, (Entegra Power Group, 2014)	8 GE 7FA natural-gas–fired CTGs	2,200 MW	SCR	2.0 ppm (1-hour)	Operation from 2003
Duke Energy Arlington Valley (Industcards, 2014)	2 GE 7001FA natural-gas–fired CTGs	570 MW	SCR	2.0 ppm (1-hour)	Operation from 2002
IDC Bellingham (Commonwealth of MA, 1999)	2 Westinghouse 501G natural gas fired CTGs, 285 MW from each CTG	700 MW	SCR	2.0 ppm (1-hour)	Operation from 2002
Avenal Energy – Avenal Power Center, LLC (CEC, 2009a)	2 GE 7FA natural-gas–fired CTGs , 180 MW from each CTG	600 MW	DLN burners, SCR	2.0 ppm (1-hour)	Approved in 2009
Russell City Energy Center (CEC, 2002, 2011a)	2 Siemens Westinghouse 501F natural-gas–fired CTGs, 2038.6 MMBtu/hr from each turbine	600 MW	SCR	2.0 ppm (1-hour)	Operation from 2013

TABLE 7-2
NATURAL GAS COMBINED CYCLE NO_X BACT/LAER EMISSION LIMIT COMPARISON (CONTINUED)

Facility Name	Turbines	Facility Power Generation	BACT Emission Control	Permitted or Proposed Emission Limit (at 15 Percent O_2)	Status
Oakley Generating Station (BAAQMD, 2014; CEC, 2011d)	2 GE Frame 7FA natural-gas–fired CTGs, 213 MW from each CTG	624 MW	DLN burners, SCR	2.0 ppm (1-hour)	In construction
GWF Tracy Combined-cycle Project (CEC, 2009b)	2 GE frame 7EA natural gas fired CTGs, 145 MW from each CTG	314 MW	DLN burners, SCR	2.0 ppm (1-hour)	Operation from 2012
Watson Cogeneration Project (CEC, 2011b)	1 GE 7EA natural gas fired CTG	85 MW additional	DLN burners, SCR	2.0 ppm (1-hour)	Approved in 2012
Palmdale Hybrid Power Plant Project (CEC, 2010)	2 GE 7FA natural-gas–fired CTGs, 1 STG, 165 MW from each CTG	570 MW	DLN burners, SCR	2.0 ppm (1-hour)	Approved in 2011
Victorville Hybrid Gas-Solar (CEC, 2008a)	a hybrid of natural-gas–fired combined cycle generating equipment integrated with solar thermal components, 154 MW from each CTG	563 MW	SCR	2.0 ppm (1-hour) with and without duct burning	Approved in 2008
Morro Bay Power Plant (CEC, 2011c; U.S. EPA, 2008)	2 power blocks, each has 2 CCGT GE model PG7241 7FA natural gas fired CTGs, 180 MW from each CTG	1,200 MW	DLN burners, SCR	2.0 ppm (1-hour)	Approved in 2004; project terminated/ withdrawn.
Otay Mesa Energy Center LLC (CEC, 2000b)	2 GE 7FA natural gas fired CTGs, 171.7 MW from each CTG	590 MW	SCR	2.0 ppm (1-hour)	Operation from 2009
Colusa Generating Station (CEC, 2008b)	2 GE Power Systems Frame 7FA natural gas fired CTGs, 172 MW from each CTG	660 MW	DLN burners, SCR	2.0 ppm (1-hour)	Operation from 2010
Huntington Beach Energy Project (AES, 2012b; CEC, 2013)	2 3-on-1 combined-cycle power block will consist of 6 Mitsubishi 501DA CTGs	939 MW	DLN burners, SCR	2.0 ppm (1-hour)	In permitting
Redondo Beach Energy Project (AES, 2012b)	3-on-1 combined-cycle power block will consist of 3 Mitsubishi Power Systems Americas 501DA CTGs	511 MW	DLN burners, SCR	2.0 ppm (1-hour)	In permitting

TABLE 7-2
NATURAL GAS COMBINED CYCLE NO_X BACT/LAER EMISSION LIMIT COMPARISON (CONTINUED)

Facility Name	Turbines	Facility Power Generation	BACT Emission Control	Permitted or Proposed Emission Limit (at 15 Percent O_2)	Status
Alamitos Energy Center (AES, 2012a)	4 3-on-1 combined cycle gas turbine power blocks with twelve natural-gas-fired	1,995 MW	DLN burners, SCR	2.0 ppm (1-hour)	In permitting
Marshalltown Generating Station (Iowa) (U.S. EPA, 2014)	2 Siemens SGT6-5000F natural-gas–fired CTGs, 300 MW from each CTG.	650 MW	DLN burners, SCR	2.0 ppm (1-hour)	In construction
FGE Texas Power I and II (U.S. EPA, 2014)	4 Alstom GT24 natural-gas–fired CTGs	1,494 MW	DLN burners, SCR	2.0 ppm (1-hour)	In construction
Pinecrest Energy Center, LLC (U.S. EPA, 2014)	2 CTGs, models being considered: GE 7FA.05, Siemens SGT6-5000F(4) or (5), 250 MW from each CTG	637-735 MW	DLN burners, SCR	2.0 ppm (1-hour)	In permitting
Thetford Generating Station (Michigan) (U.S. EPA, 2014)	Two, 2-on-1 combined-cycle power blocks, F-class CTG model technologies, 230 MW (gross) per CTG	1,400 MW	DLN burners, SCR	3.0 ppm (rolling 24-hour average); 760 lb/hr (1-hour) per each CTG.	In permitting
Oregon Clean Energy Center (U.S. EPA, 2014)	2 CTGs, models being considered: Mitsubishi M501 GAC or Siemens SGT-8000H,	800 MW	DLN burners, SCR	2.0 ppm (1-hour)	In permitting

Notes:

MW represents gross power unless otherwise noted.

BACT = Best Available Control Technology
CCGT = combined cycle gas turbine
CTG = combustion turbine generators
DLN = dry low-NO_X burners
GE = General Electric Company
HRSG = heat recovery steam generator
LAER = Lowest Available Emission Rate
lb/hr = pounds per hour
MMBtu/hr = million British thermal units per hour
MW = megawatt
NO_X = oxides of nitrogen
O_2 = oxygen
ppm = parts per million
SCR = selective catalytic reduction
STG = steam turbine generator

NSPS 40 CFR 60 Subpart KKKK, is considered as the BACT "floor" for this source category. As shown above, the BACT emission limit proposed for IEEC is significantly lower than the applicable NSPS Subpart KKKK limit of 15 ppm NO_X at 15 percent O_2.

The principal environmental consideration with respect to implementation of SCR is that, although it will reduce NO_X emissions, it will add NH_3 emissions associated with use of NH_3 as the reagent chemical. A portion of the NH_3 passes unreacted through the catalyst and is emitted from the stack. This is called NH_3 slip, and the magnitude of these emissions depends on the catalyst activity and the degree of NO_X control desired. For the IEEC, the concentration of NH_3 slip is currently limited to 5 ppmvd at 15 percent O_2.

7.1.5 Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. The NO_X control technologies selected as BACT for the IEEC 7HA.01 CT are the use of DLN combustors and a SCR system to control emissions to 2 ppmvd at 15 percent O_2 on a 1-hour basis.

The NH_3 slip from use of SCR to reduce 7HA.01 NO_X emissions will be limited to 5 ppmvd at 15 percent O_2.

These BACT limitations for NO_X and NH_3 emissions from the IEEC 7HA.01 CT are at least—if not more stringent than—the historic BACT determinations for other recently permitted NGCC units.

7.2 CARBON MONOXIDE BACT ANALYSIS FOR THE 7HA.01 CT

CO is a product of incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. However, these same control factors can increase NO_X emissions. Conversely, lower NO_X emission rates achieved through flame temperature control (by diluent injection) can increase CO emissions. Therefore, a compromise must be established whereby the flame temperature reduction is set to achieve the lowest NO_X emission rate possible while keeping CO emissions to an acceptable level.

7.2.1 Identify Control Technologies

The following CO control technologies were evaluated for the proposed 7HA.01 turbine replacement:

- Combustion process controls:
  - Good combustion practices (GCP)

- Post-combustion controls:
  - $SCONO_X$™
  - Oxidation catalyst

7.2.2 Evaluate Technical Feasibilities

Good Combustion Practices

GCPs include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure optimum complete combustion.

$SCONO_X$™

The $SCONO_X$ system was evaluated in the NO_X BACT analysis, and determined to be not technically feasible for this unit for reasons cited above in the NO_X BACT evaluation.

Oxidation Catalyst

Catalytic oxidation is a post-combustion control technology that uses a catalyst to oxidize CO into CO_2. Oxidation catalysts have been successfully installed on numerous combined-cycle turbines, and are therefore considered technically feasible.

7.2.3 Rank Control Technologies

Use of an oxidation catalyst and GCPs for the turbines is the only technically feasible CO control technologies identified.

7.2.4 Evaluate Control Options

Table 7-3 shows the typical CO BACT determinations and control technology for other recently permitted NGCC projects. As shown in Table 7-3, the BACT limitation for CO emissions from the IEEC 7HA.01 CT is as stringent as most of the historic BACT determinations for other permitted NGCC units.

Two facilities, Avenal Power Center and Warren County Power Station, have proposed to meet lower CO emission levels when not duct-firing at 1.5 ppm. This limit is lower than the proposed 2 ppm for IEEC for operation. Neither of these facilities is operational; therefore, these emission levels have not been achieved in practice.

7.2.5 Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As explained, GCPs and oxidation catalyst are the appropriate control technique for setting BACT-based emission limits.

IEEC proposes the CO BACT-based limit of 2 ppmvd at 15 percent O_2 using an oxidation catalyst and GCPs for the 7HA.01. This BACT limitation for CO emissions from the IEEC 7HA.01 CT is at least as stringent as historic BACT determinations for other recently permitted NGCC units.

TABLE 7-3
NATURAL GAS COMBINED CYCLE CO BACT EMISSION LIMIT COMPARISON

Facility Name	Turbines	Facility Power Generation	BACT Emission Control	Permitted or Proposed Emission Limit (at 15 Percent O_2)	Status
Otay Mesa Energy Center LLC (CEC, 2000b)	2 GE 7FA natural-gas–fired CTGs, 171.7 MW from each CTG	590 MW	Oxidation catalyst system	6.0 ppm (3-hour)	Operation from 2009
High Desert Power Project(MDAQMD, 1999)	3 Siemens Westinghouse W501FD2s natural-gas–fired CTGs, 190 MW from each CTG	830 MW	Oxidation catalyst system	4 ppm (24-hour)	Operation from 2003
Blythe Energy Project II (CEC, 2005)	2 Siemens SGT6-5000F natural-gas–fired CTGs, 1 steam turbine, 170 MW from each CTG	520 MW	Oxidation catalyst system	4.0 ppm (3-hour)	Approved in 2005
Palomar Escondido – SDG&E (CEC, 2003)	2 GE 7FA natural-gas–fired CTGs, 1 STG, 165 MW from each CTG	570 MW	Oxidation catalyst system	4.0 ppm (3-hr average)	Operation from 2009
Sutter – Calpine (CEC, 2014)	2 Siemens Westinghouse 501FC natural-gas–fired CTGs with HRSG and duct firing, 170 MW from each CTG	540 MW	Oxidation catalyst system	4.0 ppm (3-hour)	Operation from 2001
Elk Hills Power LLC (CEC, 2000a)	2 GE natural-gas–fired CTGs, Each CTG system will generate 166 MW plus 171 MW from the STG	500 MW	Oxidation catalyst system	4 ppm (1-hour)	Operation from 2003
Colusa Generating Station (CEC, 2008b)	2 GE Power Systems Frame 7FA natural-gas–fired CTGs at 172 MW each, both turbines equipped with a 688 MMBtu/hr duct burner and HRSG	660 MW	Oxidation catalyst system	3.0 ppm (3-hour)	Operation from 2010
GWF Tracy Combined-cycle Project (CEC, 2009b)	2 GE frame 7EA natural-gas–fired CTGs, 145 MW from each CTG	314 MW	Oxidation catalyst system	2 ppm (3-hour)	Operation from 2012
Duke Energy Arlington Valley (Industcards, 2014)	2 GE 7001FA natural-gas–fired CTGs	570 MW	Oxidation catalyst system	2 ppm (3-hour)	Operation from 2002

TABLE 7-3
NATURAL GAS COMBINED CYCLE CO BACT EMISSION LIMIT COMPARISON (CONTINUED)

Facility Name	Turbines	Facility Power Generation	BACT Emission Control	Permitted or Proposed Emission Limit (at 15 Percent O_2)	Status
Morro Bay Power Plant (CEC, 2011c; U.S. EPA, 2008)	2 power blocks, each has 2 CCGT GE model PG7241 7FA natural-gas–fired CTGs, 180 MW from each CTG	1,200 MW	Oxidation catalyst system	2.0 ppm (3-hour)	Approved in 2004; project terminated/ withdrawn.
Palmdale Hybrid Power Plant Project (CEC, 2010)	2 GE 7FA natural-gas–fired CTGs, 1 STG, 165 MW	570 MW	Oxidation catalyst system	2.0 ppm without duct burners (1-hour); 3.0 ppm with duct burners (1-hour)	Approved in 2011
Victorville Hybrid Gas-Solar (CEC, 2008a)	A hybrid of natural-gas–fired combined cycle generating equipment integrated with solar thermal components, 154 MW from each CTG	563 MW	Oxidation catalyst system	2.0 ppm (1-hour) no duct burning and 3.0 ppm (1-hour) with duct burning	Approved in 2008
Watson Cogeneration Project (CEC, 2011b)	1 GE 7EA natural-gas–fired CTG	85 MW additional	Oxidation catalyst system	2.0 ppm (1-hour), and 3.0 ppm (2-hour)	Approved in 2012
Avenal Energy – Avenal Power Center, LLC (CEC, 2009a)	2 GE 7FA natural-gas–fired CTGs , 180 MW from each CTG	600 MW	Oxidation catalyst system	1.5 ppm without duct burners (3-hour);2.0 ppm with duct burners (3-hour)	Approved in 2009
Patriot Power Generation Plant (Moxie Energy, 2014)	2 natural-gas–fired CTGs, 225-250 MW from each CTG	700 MW	Oxidation catalyst system	2.0 ppm	In construction
Oakley Generating Station (BAAQMD, 2014; CEC, 2011d)	2 GE Frame 7FA natural-gas–fired CTGs, 213 MW from each CTG	624 MW	Oxidation catalyst system	2.0 ppm (1-hour)	In construction

TABLE 7-3
NATURAL GAS COMBINED CYCLE CO BACT EMISSION LIMIT COMPARISON (CONTINUED)

Facility Name	Turbines	Facility Power Generation	BACT Emission Control	Permitted or Proposed Emission Limit (at 15 Percent O_2)	Status
IDC Bellingham (Commonwealth of MA, 1999)	2 Westinghouse 501G natural-gas–fired CTGs, 285 MW from each CTG	700 MW	Oxidation catalyst system	2.0 ppm (1-hour)	Operation from 2002
Russell City Energy Center (CEC, 2002, 2011a)	2 Siemens Westinghouse 501F natural-gas–fired CTGs, 2038.6 MMBtu/hr from each turbine	600 MW	Oxidation catalyst system	2.0 ppm with duct burners (1-hour)	Operation from 2013
Magnolia Power Project (CARB, 2014)	1 GE 7001FA natural-gas–fired CTG	310 MW	Oxidation catalyst system	2.0 ppm with duct burners (1-hour)	Operation from 2005
Huntington Beach Energy Project (AES, 2012b; CEC, 2013)	2 3-on-1 combined-cycle power block will consist of 6 Mitsubishi 501DA CTGs	939 MW	Oxidation catalyst system	2.0 ppm (1-hour)	In permitting
Redondo Beach Energy Project (AES, 2012b)	3-on-1 combined-cycle power block will consist of 3 Mitsubishi Power Systems Americas 501DA CTGs	511 MW	Oxidation catalyst system	2.0 ppm (1-hour)	In permitting
Alamitos Energy Center (AES, 2012a)	4 3-on-1 combined cycle gas turbine power blocks with twelve natural-gas-fired	1,995 MW	Oxidation catalyst system	2.0 ppm (1-hour)	In permitting
Warren County Power Station (VA DEQ, 2010a, 2010b, 2014)	3 MHI M501GAC natural-gas–fired CTGs	1,300 MW	Oxidation catalyst system	1.5 ppm without duct burners, 2.4 ppm with duct burners	In construction
Marshalltown Generating Station (Iowa) (U.S. EPA, 2014)	2 Siemens SGT6-5000F natural-gas–fired CTGs, 300 MW from each CTG	650 MW	Oxidation catalyst system	2.0 ppm (30-day rolling average)	Approved in 2014 (under construction)

TABLE 7-3
NATURAL GAS COMBINED CYCLE CO BACT EMISSION LIMIT COMPARISON (CONTINUED)

Facility Name	Turbines	Facility Power Generation	BACT Emission Control	Permitted or Proposed Emission Limit (at 15 Percent O_2)	Status
FGE Texas Power I and II (U.S. EPA, 2014)	4 Alstom GT24 natural-gas–fired CTGs	1,494 MW	Oxidation catalyst system	2.0 ppm (3-hour rolling average)	Approved in 2014 (under construction)
Pinecrest Energy Center, LLC (Texas) (U.S. EPA, 2014)	2 CTGs, models being considered: GE 7FA.05, Siemens SGT6-5000F(4) or (5), 250 MW from each CTG	637-735 MW	Oxidation catalyst system	2.0 ppm (80-100% load) (3-hour rolling average); 4.0 ppm (60-80% load) (3-hour rolling average)	In permitting
Thetford Generating Station (Michigan) (U.S. EPA, 2014)	Two, 2-on-1 combined-cycle power blocks, F-class CTG model technologies, 230 MW (gross) per CTG	1,400 MW	Oxidation catalyst system	4.0 ppm (rolling 24-hour average); 3,159 lb/hr (4-hour rolling average)	In permitting
Oregon Clean Energy Center (U.S. EPA, 2014)	2 CTGs, models being considered: Mitsubishi M501 GAC or Siemens SGT-8000H	800 MW	Oxidation catalyst system	2.0 ppm (averaging period not specified)	In permitting

Notes:

MW represents gross power unless otherwise noted.

BACT = Best Available Control Technology
CCGT = combined cycle gas turbine
CO = carbon monoxide
CTG = combustion turbine generators
GE = General Electric Company
HRSG = heat recovery steam generator
lb/hr = pounds per hour
MMBtu/hr = million British thermal units per hour
MW = megawatt
O_2 = oxygen
ppm = parts per million
STG = steam turbine generator

7.3 PARTICULATE MATTER EMISSIONS BACT ANALYSIS FOR THE 7HA.01 CT

Particulate matter (PM) emissions from gas-fired combustion sources consist of non-combustible contaminants in gaseous fuel, sulfates from fuel sulfur, NH_3 compounds from the SCR reagent, dust drawn in from the ambient air that passes through the CTs inlet air filters, and particles of carbon and condensed hydrocarbon compounds resulting from incomplete combustion.

Because all of the PM emissions from the turbines are assumed to be less than 2.5 microns in size, in this analysis, all emissions will be referred to as PM emissions. This covers the PM, PM_{10}, and $PM_{2.5}$ emissions, because all are considered the same for NGCC units.

7.3.1 Identify Control Technologies

The following PM control technologies were evaluated for the proposed 7HA.01 turbine replacement:

- Pre-combustion controls:
  - Use of fuels that have low ash and sulfur content
  - Inlet air filtration system

- Combustion process controls:
  - GCPs

- Post-combustion controls:
  - Baghouse
  - Electrostatic precipitation

7.3.2 Evaluate Technical Feasibilities

Use of Fuels that have Low Ash and Sulfur Content

Fuel sulfur, when combusted, forms various sulfur oxides (SO_X), including SO_2 and sulfuric acid (H_2SO_4), that can react with other exhaust constituents (e.g., NH_3 from an SCR) to form condensable PM.

Inlet Air Filtration System

The inlet air filtration system filters the ambient air prior to entering the turbine to reduce PM that is ultimately passed through in the exhaust.

Good Combustion Practices

GCPs include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure optimum complete combustion.

Baghouse or Electrostatic Precipitation

Post-combustion controls, such as electrostatic precipitators (ESP) or baghouses, have never been applied to commercial CTs burning gaseous fuels, due to the low quantity of PM. Therefore, the use of ESPs and baghouses are considered technically infeasible and are not demonstrated-in-practice control technology for CTs.

7.3.3 Rank Control Technologies

The combination of low-ash, low-sulfur fuel, such as natural gas, inlet air filtration, and GCPs is the most effective control method demonstrated for gas-fired CTs.

7.3.4 Evaluate Control Options

The U.S. EPA has indicated that PM control devices are not typically installed on CTs, and that the cost of installing a PM control device is prohibitive. When the NSPS for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the U.S. EPA acknowledged, "Particulate emissions from stationary gas turbines are minimal." Similarly, the most recently revised NSPS for Stationary Gas Turbines Subpart KKKK NSPS (2006) did not impose a particulate emission standard. Therefore, performance standards for PM control of stationary gas turbines have not been proposed or promulgated at a federal level.

Unit 2 with the replacement turbine will continue to meet the PM_{10} emission limit of 7.5 pounds per hour, as required in the current Permit to Operate.

Table 7-4 shows the typical PM BACT and LAER determinations and control technology for other recently permitted NGCC projects. Based on the evaluation in the previous step, GCPs, the exclusive use of low-ash, low-sulfur fuel, such as natural gas, and inlet air filtration are considered as technically feasible $PM/PM_{10}/PM_{2.5}$ control technologies that are suitable for establishment of BACT limits.

7.3.5 Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. IEEC proposes to continue meeting the permitted PM BACT-based limit of 7.5 pounds per hour, using BACT GCPs, BACT clean natural gas, and BACT inlet air filtration. Note that BACT is represented by GCP, clean natural gas, and inlet filtration.

This BACT limitation for PM, PM_{10}, and $PM_{2.5}$ emissions from the IEEC CT is as stringent as historic BACT determinations for other recently permitted NGCC units.

TABLE 7-4
NATURAL GAS COMBINED CYCLE PM BACT/LAER EMISSION LIMIT COMPARISON

Facility Name	Turbines	Facility Power Generation	BACT Emission Control	Permitted or Proposed Emission Limit (at 15 Percent O_2)	Status
Victorville Hybrid Gas-Solar (CEC, 2008a)	A hybrid of natural-gas–fired combined cycle generating equipment integrated with solar thermal components, 154 MW from each CTG	563 MW	Use PUC quality natural gas	12.0 lb/hr 12-month rolling average (no duct burning), 18.0 lb/hr 12-month rolling average (with duct burning)	Approved in 2008
Palomar Escondido – SDG&E (CEC, 2003)	2 GE 7FA natural-gas–fired CTGs, 1 STG, 165 MW from each CTG	570 MW		14 lb/hr (with or without duct firing)	Operation from 2009
Colusa Generating Station (CEC, 2008b)	2 GE Power Systems Frame 7FA natural-gas–fired CTGs at 172 MW each, both turbines equipped with a 688 MMBtu/hr duct burner and HRSG	660 MW	Use natural gas	13.5 lb/hr	Operation from 2010
Sutter – Calpine (CEC, 2014)	2 Siemens Westinghouse 501FC natural-gas–fired CTGs with HRSG and duct firing, 170 MW from each CTG	540 MW		11.5 lb/hr	Operation from 2001
Avenal Energy – Avenal Power Center, LLC (CEC, 2009a)	2 GE 7FA natural-gas–fired CTGs, 180 MW from each CTG	600 MW	Use PUC quality natural gas	8.91 lb/hr (12-month rolling average) no duct burning; 11.78 lb/hr (12-month rolling average) no duct burning	Approved in 2009
Morro Bay Power Plant (CEC, 2011c; U.S. EPA, 2008)	2 power blocks, each has 2 CCGT GE model PG7241 7FA natural-gas–fired CTGs, 180 MW from each CTG	1,200 MW	Use pipeline quality natural gas, operate duct burners no more than 4,000 hours per year (12-month rolling average basis)	11 lb/hr (6-hour rolling average [no duct burning]) or 0.0054 lb/MMBtu	Approved in 2004; project terminated/ withdrawn.
Russell City Energy Center (CEC, 2002, 2011a)	2 Siemens Westinghouse 501F natural-gas–fired CTGs, 2038.6 MMBtu/hr from each turbine	600 MW	Use PUC quality natural gas	7.5 lb/hr or 0.0036 lb/MMBtu	Operation from 2013

TABLE 7-4
NATURAL GAS COMBINED CYCLE PM BACT/LAER EMISSION LIMIT COMPARISON (CONTINUED)

Facility Name	Turbines	Facility Power Generation	BACT Emission Control	Permitted or Proposed Emission Limit (at 15 Percent O_2)	Status
Warren County Power Station (VA DEQ, 2010a, 2010b, 2014)	3 MHI M501GAC natural-gas–fired CTGs; 300 MW from each CTG	1,300 MW	Use PUC-quality natural gas	RBLC 3-hour average limit is 8 lb/hr or 0.0027 lb/MMBtu without duct firing; and 14 lb/hr, 0.0040 lb/MMBtu with duct firing. PSD permit limit is 12 lb/hr = 0.0040 lb/MMBtu no duct firing and 18 lb/hr = 0.0052 lb/MMBtu with duct firing	In construction
Pinecrest Energy Center, LLC (U.S. EPA, 2014)	2 CTGs, models being considered: GE 7FA.05, Siemens SGT6-5000F(4) or (5), 250 MW from each CTG	637-735 MW	Use pipeline-quality natural gas and GCP	26.2 lb/hr	In permitting
Thetford Generating Station (Michigan) (U.S. EPA, 2014)	Two 2-on-1 combined-cycle power blocks, F-class CTG model technologies, 230 MW (gross) per CTG	1,400 MW	Use pipeline-quality natural gas, use inlet air filtration, and GCP	0.0033 lb/MMBtu	In permitting
Oregon Clean Energy Center (U.S. EPA, 2014)	2 CTGs, models being considered: Mitsubishi M501 GAC or Siemens SGT-8000H, in CC configuration	800 MW	Use pipeline-quality natural gas	10.1 lb/hr	In permitting

Notes:

MW represents gross power unless otherwise noted.

BACT = Best Available Control Technology
CCGT = combined cycle gas turbine
CTG = combustion turbine generators
GCP = good combustion practices
GE = General Electric Company
HRSG = heat recovery steam generator
LAER = Lowest Available Emission Rate
lb/hr = pounds per hour
lb/MMBtu = pound per million British thermal unit
MMBtu/hr = million British thermal units per hour
MW = megawatt
O_2 = oxygen
PM = particulate matter
PSD = Prevention of Significant Deterioration
PUC = Public Utilities Commission
RBLC = RACT/BACT/LAER Clearinghouse
STG = steam turbine generator

7.4 SULFUR DIOXIDE BACT ANALYSIS FOR THE 7HA.01 CT

SO_2 emissions from any combustion process are largely defined by the sulfur content of the fuel being combusted and the rate of the fuel use. The combustion of natural gas in the CTs creates primarily SO_2, and small amounts of sulfite (SO_3), by the oxidation of the fuel sulfur. The SO_3 reacts with the moisture in the exhaust and in the atmosphere to form sulfuric acid mist, or H_2SO_4. Emissions of these sulfur species can be controlled, either by limiting the sulfur content of the fuel (pre-combustion control), or by scrubbing the SO_2 from the exhaust gas (post-combustion control, also referred to as flue gas desulfurization [FGD]). Any technology that reduces the sulfur input to the turbines will reduce both sulfuric acid mist and SO_2; fuel is the only input source of sulfur.

7.4.1 Identify Control Technologies

The following SO_2 and sulfuric acid mist control technologies were evaluated for the proposed 7HA.01 replacement turbine when operating on natural gas fuel:

Pre-Combustion Controls

- Use of low sulfur fuel

Post-Combustion Controls

- FGD

7.4.2 Evaluate Technical Feasibilities

- Use of low-sulfur fuel

Limiting the amount of sulfur in the fuel is common practice for natural-gas–fired power plants. This control technique has been achieved in practice at other facilities, and it is technologically feasible and cost-effective. IEEC will use Public Utilities Commission (PUC)-grade natural gas with less than 0.25 grain/100 standard cubic feet (scf) hydrogen sulfide (H_2S) content, per the current Permit to Operate.

- FGD

FGD is a post-combustion SO_2 control technology that causes an alkaline substance to react with SO_2 in the exhaust gas. FGD systems are commonly employed in conventional coal-fired and oil-fired power plant and industrial boilers, where the concentration of oxidized sulfur species in the exhaust is relatively high. Industrial CTs burning natural gas produce very low sulfur oxide concentrations in the combustor. Unlike boiler exhaust, which has a relatively small amount of excess air (~5% O_2 in the exhaust), industrial CTs operate with a much higher amount of air (~15% O_2 in the exhaust), resulting in very low SO_2 concentrations in a large volume of air compared to boilers. Therefore, SO_X concentrations in the natural gas CT exhaust gases are too low (less than 1 ppm) for the FGD scrubbing technologies to work effectively or be technologically feasible. Therefore, FGD is not considered technically feasible for a natural-gas–fired power plant, and will not be considered further in this BACT analysis.

7.4.3 Rank Control Technologies

Only one control method is considered technically feasible: the use of low-sulfur natural gas.

7.4.4 Evaluate Control Options

NSPS 40 CFR 60 Subpart KKKK is considered as the BACT "floor" for this category of new sources. The replacement turbine will comply with the SO_2 limits in this regulation by meeting the fuel sulfur limit of less than 0.060 pound of SO_2 per million British thermal units; this can be demonstrated by firing natural gas with 20 grains or less of sulfur per 100 scf.

7.4.5 Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps.

The SO_2 BACT for the proposed IEEC CT replacement is PUC-grade natural gas fuel with less than 0.25 grain/100 scf H_2S content. This BACT limitation for SO_2 emissions from the IEEC 7HA.01 CT is at least—if not more stringent than—the historic BACT determinations for other recently permitted NGCC units.

7.5 VOLATILE ORGANIC COMPOUNDS BACT ANALYSIS FOR THE 7HA.01 CT

VOCs are a product of incomplete combustion of the organic components in the natural gas. Reductions in VOC formation in CT combustors are accomplished by providing adequate combustion air, fuel residence time and a high temperature in the combustion zone to ensure complete combustion.

7.5.1 Identify Control Technologies

The following VOC control technologies were evaluated for the proposed 7HA.01 replacement turbine:

- Combustion process controls:
  - GCPs
- Post-combustion controls:
  - $SCONO_X$™
  - Oxidation catalyst

7.5.2 Evaluate Technical Feasibilities

Good Combustion Practices

GCPs include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure optimum complete combustion.

This technology has been determined to be BACT for VOC emissions in other operational or recently permitted NGCC projects. A survey of the RBLC database indicated that GCPs and burning clean gaseous fuel are the VOC control technologies primarily determined to be BACT.

$SCONO_X$™

The $SCONO_X$ system was evaluated in the NO_X BACT analysis, and determined to be not technically feasible for this unit for reasons cited above in that analysis.

Oxidation Catalyst

Catalytic oxidation is a post-combustion control technology that uses a catalyst to oxidize VOC. The catalyst beds that functions to reduce CO emissions can also be effective in reducing VOC emissions. Such systems typically achieve a maximum VOC removal efficiency of up to 30 to 50 percent, while providing control for CO.

7.5.3 Rank Control Technologies

Oxidation catalyst is the only technically feasible VOC control technology identified in addition to GCPs. This is the top control option and consistent with recent BACT determinations for NGCC turbines.

7.5.4 Evaluate Control Options

BACT for VOC emissions from the IEEC 7HA.01 CT will be achieved by using efficient combustor technology and the HRSG's existing oxidation catalyst as a post-combustion control technology to reduce VOC emissions and GCPs. IEEC will continue to meet emission levels of 1 ppmvd at 15 percent O_2.

Table 7-5 shows the typical VOC BACT and LAER determinations and control technology for other recently permitted NGCC projects.

As shown in Table 7-5, the BACT limitation for VOC emissions from the IEEC 7HA.01 CT is comparable to the historic BACT determinations for other recently permitted NGCC turbines without duct-firing.

TABLE 7-5
NATURAL GAS COMBINED CYCLE VOC BACT/LAER EMISSION LIMIT COMPARISON

Facility Name	Turbines	Facility Power Generation	BACT Emission Control	Permitted or Proposed Emission Limit (at 15 percent O_2)	Status
Blythe Energy Project II (CEC, 2005)	2 Siemens SGT6-5000F natural-gas–fired CTGs, 1 steam turbine, 170 MW from each CTG	520 MW	Oxidation catalyst system	4.0 ppm (3-hour)	Approved in 2005
Palomar Escondido – SDG&E (CEC, 2003)	2 GE 7FA natural-gas–fired CTGs, 1 STG, 165 MW from each CTG	570 MW	Oxidation catalyst system	2.0 ppmvd at 15 percent O_2 (3-hr average)	Operation from 2009
Watson Cogeneration Project (CEC, 2011b)	1 GE 7EA natural-gas–fired CTG, 85 MW	85 MW additional	Oxidation catalyst system	2.0 ppm without duct burners (1-hour); 2.0 ppm with duct burners (1-hour)	Approved in 2012
Otay Mesa Energy Center LLC (CEC, 2000b)	2 GE 7FA natural-gas–fired CTGs , 171.7 MW from each CTG	590 MW	Oxidation catalyst system	2 ppm (1-hour)	Operation from 2009
Colusa Generating Station (CEC, 2008b)	2 GE Power Systems Frame 7FA natural-gas–fired CTGs at 172 MW each, both turbines equipped with a 688 MMBtu/hr duct burner and HRSG	660 MW	Oxidation catalyst system	2.0 ppm (1-hour)	Operation from 2010
GWF Tracy Combined-cycle Project (CEC, 2009b)	2 GE frame 7EA natural-gas–fired CTGs, 145 MW from each CTG	314 MW	Oxidation catalyst system	1.5 ppm without duct burners (3-hour); 2.0 ppm with duct burners (3-hour)	Operation from 2012
Avenal Energy – Avenal Power Center, LLC (CEC, 2009a)	2 GE 7FA natural-gas–fired CTGs, 180 MW from each CTG	600 MW	Oxidation catalyst system	1.4 ppm without duct burners; 2.0 ppm with duct burners (3-hour)	Approved in 2009

TABLE 7-5
NATURAL GAS COMBINED CYCLE VOC BACT/LAER EMISSION LIMIT COMPARISON

Facility Name	Turbines	Facility Power Generation	Emission Control	Emission Limit (at 15 percent O_2)	Status
Palmdale Hybrid Power Plant Project (CEC, 2010)	2 GE 7FA natural-gas–fired CTGs, 1 STG, 165 MW from each CTG	570 MW	Oxidation catalyst system	1.4 ppm without duct burners (1-hour); 2.0 ppm with duct burners (1-hour)	Approved in 2011
Victorville Hybrid Gas-Solar (CEC, 2008a)	A hybrid of natural-gas–fired combined cycle generating equipment integrated with solar thermal components, 154 MW from each CTG	563 MW	Oxidation catalyst system	1.4 ppm without duct burners; 2.0 ppm with duct burners	Approved in 2008
Duke Energy Arlington Valley (Industcards, 2014)	2 GE 7001FA natural-gas–fired CTGs	570 MW	Oxidation catalyst system	1 ppm without duct burners (3-hour); 4 ppm with duct burners (3-hour)	Operation from 2002
Sutter – Calpine (CEC, 2014)	2 Siemens Westinghouse 501FC natural-gas–fired CTGs with HRSG and duct firing, 170 MW from each CTG	540 MW	Oxidation catalyst system	1.0 ppm with duct burners (calendar day average)	Operation from 2001
Oakley Generating Station (CEC, 2011d)	2 GE Frame 7FA natural-gas–fired CTGs, 213 MW from each CTG	624 MW	Oxidation catalyst system	1.0 ppm (1-hour) (no duct burners)	In construction
Patriot Power Generation Plant (Moxie Energy, 2014)	2 natural-gas–fired CTGs, 225-250 MW from each CTG	700 MW	Oxidation catalyst system	1.0 ppm without duct burners	In construction
Huntington Beach Energy Project (AES, 2012b; CEC, 2013)	Two 3-on-1 combined-cycle power block will consist of 6 Mitsubishi 501DA CTGs	939 MW	Oxidation catalyst system	1.0 ppm (1-hour) without duct burners; 1.0 ppm with duct burners (3-hour)	In permitting

TABLE 7-5
NATURAL GAS COMBINED CYCLE VOC BACT/LAER EMISSION LIMIT COMPARISON

Facility Name	Turbines	Facility Power Generation	Emission Control	Emission Limit (at 15 percent O_2)	Status
Redondo Beach Energy Project (AES, 2012b)	3-on-1 combined-cycle power block will consist of 3 Mitsubishi Power Systems Americas 501DA CTGs	511 MW	Oxidation catalyst system	1.0 ppm (1-hour) without duct burners; 1.0 ppm with duct burners (3-hour)	In permitting
Alamitos Energy Center (AES, 2012a)	Four 3-on-1 combined cycle gas turbine power blocks with twelve natural-gas fired	1,995 MW	Oxidation catalyst system	1.0 ppm (1-hour)	In permitting
Russell City Energy Center (CEC, 2002, 2011a)	2 Siemens Westinghouse 501F natural-gas–fired CTGs, 2038.6 MMBtu/hr from each turbine	600 MW	Oxidation catalyst system	1.0 ppm with duct burners (1-hour)	Operation from 2013
Warren County Power Station (VA DEQ, 2010a, 2010b, 2014)	3 MHI M501GAC natural-gas–fired CTGs	1,300 MW	Oxidation catalyst system	0.7 ppm without duct burners (3-hour); 1.6 ppm with duct burners (3-hour)	In construction
Chouteau Power Plant (U.S. EPA, 2001; Kiewit, 2014; Power-technology, 2014)	2 Siemens V84.3A2 natural-gas–fired CTGs, 176 MW for each CTG	495 MW	Oxidation catalyst system	0.7 ppm (3-hour) with duct burners	Approved and is expected to operate in March 2014
Marshalltown Generating Station (Iowa) (U.S. EPA, 2014)	2 Siemens SGT6-5000F natural-gas–fired CTGs, 300 MW from each CTG.	650 MW	Oxidation catalyst system	1.0 ppm (average of three 1-hour tests)	Approved in 2014 (under construction)
FGE Texas Power I and II (U.S. EPA, 2014)	4 Alstom GT24 natural-gas–fired CTGs	1,494 MW	Oxidation catalyst system	2.0 ppm (rolling 3-hour average)	Approved in 2014 (under construction)

TABLE 7-5
NATURAL GAS COMBINED CYCLE VOC BACT/LAER EMISSION LIMIT COMPARISON

Facility Name	Turbines	Facility Power Generation	Emission Control	Emission Limit (at 15 percent O_2)	Status
Pinecrest Energy Center, LLC (U.S. EPA, 2014)	2 CTGs, models being considered: GE 7FA.05, Siemens SGT6-5000F(4) or (5), 250 MW from each CTG	637-735 MW	Oxidation catalyst system	2.0 ppm (initial stack test)	In permitting
Thetford Generating Station (Michigan) (U.S. EPA, 2014)	Two 2-on-1 combined-cycle power blocks, F-class CTG model technologies, 230 MW (gross) per CTG	1,400 MW	Oxidation catalyst system	None (CO as surrogate)	In permitting
Oregon Clean Energy Center (U.S. EPA, 2014)	2 CTGs, models being considered: Mitsubishi M501 GAC or Siemens SGT-8000H,	800 MW	Oxidation catalyst system	2.0 ppm (averaging time not specified)	In permitting

Notes:

MW represents gross power unless otherwise noted

BACT = Best Available Control Technology
CO = carbon monoxide
CTG = combustion turbine generators
GE = General Electric Company
HRSG = heat recovery steam generator
LAER = Lowest Available Emission Rate
MMBtu/hr = million British thermal units per hour
MW = megawatt
ppm = parts per million
ppmvd = parts per million by volume, dry basis, corrected to 15 percent O_2
O_2 = oxygen
STG = steam turbine generator
VOC = volatile organic compound

7.5.5 Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As explained, GCPs and oxidation catalyst are the appropriate control technique for setting the BACT-based emission limit.

IEEC will continue to meet the VOC BACT-based limit of 1 ppmvd at 15 percent O_2, using GCPs and oxidation catalyst. This BACT limitation for VOC emissions from IEEC 7HA.01 CT is as stringent as historic BACT/LAER determinations for other recently permitted NGCC units that have been achieved in practice.

7.6 STARTUP AND SHUTDOWN BACT ANALYSIS FOR THE CT

The 7HA.01 turbine replacement with ST Rapid Response equipment will allow the Single Shaft Combined Cycle plant to achieve emissions compliance load in about half the time required by the existing system, while retaining its high efficiency at full load. The gas turbine can achieve permitted emissions levels in 25 to 45 minutes, in comparison to greater than 90 minutes for a traditional combined cycle plant. The result is faster, more efficient dispatch power, which will significantly reduce start-up emissions.

In addition, GE technology enables the 7HA.01 turbine to stay in emissions compliance while following load over a wider range than many other available CT technologies, thereby reducing the number of starts and stops, which complements renewable energy variability. By integrating control of the gas turbine and SCR, the plant is capable of low total plant emissions out of the stack, while ramping up or down.

Emission rates of all criteria pollutants except SO_2 and PM_{10} will be slightly higher during turbine startup than at steady-state operations. This is partially due to lower control effectiveness of the SCR and Oxidation Catalyst control systems until the exhaust gases reach optimal operating temperatures; also due to the slightly lower combustion efficiency of gas turbines at low loads, particularly during cold starts. Consequently, the most effective consideration for minimizing emissions due to startup and shutdown events is to minimize the frequency and duration of these events. However, as discussed, the 7HA.01 turbine minimizes start times, and therefore, the total hourly emission levels.

Table 7-6 presents two possible schedules for startups and shutdowns for the 7HA.01 turbine at IEEC. Both a Baseload Scenario and a Cycling Scenario have been analyzed to determine emissions from the range of operating profiles that may occur, depending on future market conditions. The time per event represents how long it takes for the turbine to reach emission compliance, but not necessarily to reach full-load operation. Cold-startup data are based on an extended gas turbine shutdown, greater than 72 hours; warm-startup data are based on the turbine being shut down between 8 and 72 hours; and hot-startup data are based on the turbine being shut down less than 8 hours.

TABLE 7-6
ANTICIPATED IEEC TURBINE STARTUP AND SHUTDOWN SCHEDULE

Event	Number of Events Per Year Baseload Scenario	Number of Events Per Year Cycling Scenario	Time per Event (Minutes)
Cold Start	12	48	45
Warm Start	12	0	30
Hot Start	0	240	25
Shutdown	24	288	10

The following sections provide a top-down evaluation of control technologies considered for BACT for the proposed 7HA.01 turbine replacement.

7.6.1 Identify Control Technologies

A review of the RBLC database for large CTs in the last 10 years identified many entries that specifically discuss CT start-up or shut-down emissions. Most impose emission limitations per event, limitations on the length of each event, and/or limitations on the number of events. If an emission control technology was identified in these cases, it consisted of recommending the use of control equipment as soon as feasible, such as SCR or oxidation catalyst.

Based on the above review, and also examining "fast-start" technologies, the following startup/ shutdown control technologies were evaluated for the proposed 7HA.01 turbine replacement:

- Combustion Process Controls:
  - Fast-start technologies
  - Several aspects of good air pollution control work practices (i.e., complete events as quickly as possible following manufactures recommendation and or startup, shutdown, or malfunction plans)

7.6.2 Evaluate Technical Feasibilities

Fast-Start Technologies

Fast-start technologies are offered by GE, Alstom, Siemens, and Mitsubishi on some of their combined-cycle turbine systems.

The technology consists of specialized control software that allows a more rapid startup and slightly lower turndown level on turbines. The concept is to bring the CT into emissions compliance quicker during the startup of a NGCC unit. This approach minimizes the higher emission rates associated with lower load operation, while providing adequate temperature control of the steam entering the STG. Plants that are currently using this system or are slated to employ it use DLN combustion technology. Furthermore, these facilities are generally in peaking service, where there are numerous hot and cold starts per year.

The GE 7HA.01 turbine is a fast-start unit with Rapid Response technology, thereby limiting the emissions during startups and shutdowns.

Good Air Pollution Control Work Practices

Good air pollution control work practices are feasible for the Project. The proposed 7HA.01 turbine replacement is designed to minimize the duration of startup and shutdown events by using the following work practices, operating controls, and design elements:

- Baseload Power Generation Project (inherent design feature).
- Use of SCR and CO catalyst systems during startup and shutdown when operating conditions are amenable to their effective use.
- Follow manufacturer's recommendations to minimize the duration and emissions during startup.

Another operating control/design element of the Project that inherently minimizes the emissions associated with startup and shutdown events from the CT is the use of existing SCR and CO catalyst systems. The primary purpose of these emission controls is to control emissions during operations; however, they also provide some benefit during startup and shutdown. For example, the SCR and CO catalyst systems are in the direct path of the exhaust flow throughout the startup and shutdown processes. The oxidation catalyst is in service and functioning to provide emissions control as soon as the CT operating temperature rises to a sufficient level. The SCR catalyst system will be in the exhaust gas flow path throughout startups, but will become effective for NO_X control when the temperature is sufficient to activate the NH_3 injection system. IEEC begins injection of NH_3 as soon as the exhaust gas operating conditions are amenable to its effective use, following manufacturers' recommendations.

In addition to the above aspects, IEEC will follow manufacturers' recommendations and good work practices to minimize the number and duration of startups and shutdowns; and therefore, the emissions associated with non-routine operation.

7.6.3 Rank Control Technologies

Use of a Rapid Response technology, then the use of good air pollution control practices to minimize emissions during startup and shutdown is the most effective control method demonstrated for gas-fired CTs.

7.6.4 Evaluate Control Options

IEEC proposes to use all of the technologies evaluated—turbines with Rapid Response technology and good air pollution control practices—to minimize emissions during startup and shutdown.

7.6.5 Select Control Technology

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps, and review of determinations for turbine startups and shutdowns of other NGCC projects. As a result of these considerations, BACT for the IEEC turbines startup and shutdown emissions is proposed as follows:

1. The GE 7HA.01 turbine shall be used to minimize startup and shutdown durations and emissions.

2. IEEC shall operate the CT using good work practices and following manufacturers' recommendations to minimize emissions during, and the duration of, start-up and shut-down events.

3. The CT exhaust will be routed through a SCR system and oxidation catalyst system at all times, including periods of startup and shutdown. NH_3 shall be added to the SCR system when operating conditions are amenable to its effective use.

4. IEEC shall include the emissions during periods of startup and shutdown, along with routine emissions, in determining compliance with the long-term annual emission rates that were used in the permit modeling demonstration.

SECTION 8.0
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APPENDIX D
GHG EMISSION CALCULATIONS

Greenhouse Gas Emissions
CEQA GHG Analysis

CEQA GHG Analysis	Metric tons /year (CO_2e)					
	Unit 1	Unit 2	Aux Boiler	Emergency Generators	Firewater Pump	Facility Total
Project Emissions[1,2]	522,774	1,114,759	520	105	11	1,638,168
Baseline Emissions[3]	522,774	440,782	520	105	11	964,192
Net Emissions	0	673,977	0	0	0	673,977

Notes:
1. Project emissions for Unit 2 are based on the base load operating scenario.
2. Project emissions for Unit 1, Aux Boiler, emergency generators and firewater pump are equal to baseline, since they will not be impacted by the project.
3. Baseline emissions are based on the average of CO_2e emissions reported to CARB in 2012 and 2013. Since the emergency generators and firewater pump are exempt from this reporting, emissions are calculated based on their potential to emit, assuming 50 hours/year of testing each.

Project Emissions - PTE

Pollutant	Metric tons /year	
	Unit 2 - steady-state operation	Unit 2 - startup and shutdown
CO_2	1,112,560	1,049
CH_4	21	1.98E-02
N_2O	2	1.98E-03
CO2e	1,113,708.98	1,049.76

Note: Unit 2 is the only source affected by the Project

Baseline Emissions

Year	Metric tons /year (CO_2e) [CEQA]					Metric tons /year (CO_2) [EPS Calc]	
	Unit 1	Unit 2	Aux boiler	Emergency Generators	Firewater Pump	Unit 1	Aux boiler
2012	736,901	564,612	291	105	11	736,191	291
2013	308,646	316,952	749	105	11	308,349	749
Average	522,774	440,782	520	105	11	522,270	520

Notes:
1. Unit 1, Unit 2, and aux boiler based on CARB GHG reporting
2. Emergency generators and firewater pump are exempt from reporting; emissions based on PTE

Equipment Exempt from GHG Reporting - PTE

Pollutant	Metric tons /year	
	Emergency Generators (both)	Firewater Pump
CO_2	104.97	10.57
CH_4	0.00	0.00
N_2O	0.00	0.00
CO2e	105.08	10.58

Note: Assumes permit limit of 50 hrs/yr of engine testing for each engine

Source Parameters for CEQA Calculations - Baseload Scenario

Source	Mode	events or hours per year	MMBtu/event or hour	
Unit 2	Cold Startup	12	941	
	Warm Startup	12	590	
	Hot Startup	0	414	
	Shutdown	24	58	
	Steady-State	8141	2575.6	HHV
Emergency Engines (each)	Testing	50	144	gallons/hr
Firewater Pump	Testing	50	14.5	gallons/hr

Notes:
1. Diesel energy content 137,380 Btu/gallon diesel (HHV)
Reference: http://www.afdc.energy.gov/fuels/fuel_comparison_chart.pdf
2. Unit 2 startups based on PAE base load scenario
3. Fuel use per engine from 2005 CEC Amendment Application

Greenhouse Gas Emission Factors	CO_2	CH_4	N_2O
Natural Gas (kg CO_2/mmBtu)	53.06	1.00E-03	1.00E-04
Diesel (kg CO_2/mmBtu)	73.96	3.00E-03	6.00E-04
Global Warming Potential (GWP)	1	25	298

Reference: Emission factors are from Table C-1 and C-2 of 40CFR98 Subpart C.
GWPs are from Table A-1 of 40CFR98 Subpart A

Greenhouse Gas Emissions
Emission Performance Standards (EPS) Analysis

GHG Efficiency Calcs	Unit 1 (7H)	Unit 2 (7HA)	Aux boiler	Facility Total	Standard
hours / yr	3898.2	4800	-	-	-
Gross MW	405	405	-	-	-
Gross MW-hr/yr	1,578,771	1,944,000	-	3,522,771	-
Net MW	396.63	396.63	-	-	-
Net MW-hr/yr	1,546,143	1,903,824	-	3,449,967	-
lb CO2 / yr	1,151,083,080	1,464,622,760	1,145,860	2,616,851,699	-
NSPS lb CO_2/MW-hr				743	1,000
SB1368 lb CO_2/MW-hr				759	1,100

Notes:
1. Unit 1 operational hours based on average capacity factor for 2012 and 2013 (same as emissions)
2. Unit 2 emissions based on the cycling operating scenario, which produces the most conservative calculation.
3. Unit 1 and 2 gross MW based on nameplate capacity.
4. Auxiliary load (MW) provided by IEEC.
5. For facility calculations, all equipment involved in electricity generation is included (two turbines and auxiliary boiler).

EPS Calculations	Unit 1	Unit 2	Aux Boiler
	(metric tonnes CO2)		
Project Emissions - Cycling	522,270	664,529	520

Note: Unit 1 and Aux Boiler are not affected by the Project; project emissions are equal to baseline emissions.

Source Parameters for EPS Calculations - Cycling Scenario				
Source	Mode	events or hours per year	MMBtu/event or hour	
Unit 2	Cold Startup	48	941	
	Warm Startup	0	590	
	Hot Startup	240	414	
	Shutdown	288	58	
	Steady-State	4800	2575.6	HHV

APPENDIX E
APPLICABLE AND PROPOSED CONDITIONS OF CERTIFICATION

New COC
Deleted COC
COC with modification or comment

Condition No.	Sort Code	Description	Verification	COC Revision Date	Ongoing COC with Operations No Change Req'd for 7HA.01	Not Applicable for 7HA.01 Replacement	Applicable for 7HA.01 with Modification	Comment or Recommended Change
AQ-1	OPS	Except for open abrasive blasting operations, the operator shall not discharge into the atmosphere from any single source of emissions whatsoever any air contaminant for a period or periods aggregating more than three minutes in any one hour which is: (a) As dark or darker in shade as that designated No.1 on the Ringelmann Chart, as published by the United States Bureau of Mines; or (b) Of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in subparagraph (a) of this condition. (SCAQMD F9-1)	The project owner shall document any known opacity violations in the Quarterly Operation Report (AQ-SC8). The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.	06/22/05	X			
AQ-2	CONS	The operator shall operate and maintain this equipment according to the following requirements: Within12 months of permit issuance, the Permittee will sign a Memorandum of Understanding with the U.S. Forest Service to participate in a visibility monitoring project, the results of which will be used to establish a visibility baseline in nearby Class 1 Areas. (SCAQMD E193-3)	The project owner shall make the U.S. Forest Service Memorandum of Understanding available for inspection by representatives of the District, CARB and the Commission upon request.	04/11/07		X		
AQ-3	CONS	The operator shall not burn diesel fuel containing sulfur compounds in excess of 15 ppm by weight as supplied by the supplier. (SCAQMD F14-1)	The project owner shall make fuel oil purchase, MSDS or other fuel supplier records containing diesel fuel sulfur content available for inspection by representatives of the District, CARB and the Commission upon request.	04/11/07	X			
AQ-4	OPS	Accidental release prevention requirements of Section 112(r)(7): a). The operator shall comply with the accidental release prevention requirements pursuant to 40 CFR Part 68 and shall submit to the SCAQMD Executive Officer, as a part of an annual compliance certification, a statement that certifies compliance with all of the requirements of 40 CFR Part 68, including the registration and submission of a risk management plan (RMP). b). The operator shall submit any additional relevant information requested) by the Executive Officer or designated agency. (SCAQMD F24-1)	The project owner shall submit to the District and the CPM the documents listed above as part of an annual compliance certification.	06/22/05	X			
Conditions AQ-5 through AQ-28 apply per Turbine/HRSG Unit								
AQ-5	CONS	The operator shall install and maintain a flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH3). The operator shall also install and maintain a device to continuously record the parameter being measured. The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. (SCAQMD D12-1)	The project owner shall make the site available for inspection of the ammonia flow meter and ammonia flow records by representatives of the District, CARB and the Commission.	06/22/05	X			
AQ-6	CONS	The operator shall install and maintain a temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor. The operator shall also install and maintain a device to continuously record the parameter being measured. The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. (SCAQMD D12-2)	The project owner shall make the site available for inspection of the temperature gauge on the inlet to the SCR and the continuous temperature records by representatives of the District, CARB and the Commission.	06/22/05	X			

Condition No.	Sort Code	Description	Verification	COC Revision Date	Ongoing COC with Operations No Change Req'd for 7HA.01	Not Applicable for 7HA.01 Replacement	Applicable for 7HA.01 with Modification	Comment or Recommended Change
AQ-7	CONS	The operator shall install and maintain a pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column. The operator shall also install and maintain a device to continuously record the parameter being measured. The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. (SCAQMD D12-3)	The project owner shall make the site available for inspection of the SCR catalyst bed differential pressure gauge and the differential pressure records by representatives of the District, CARB and the Commission.	06/22/05	x			
AQ-8	COMM	The test shall be conducted after District approval of the source test protocol, but no later than 180 days after initial start-up. The District shall be notified of the date and time of the test at least 10 days prior to the test. The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, and the combined gas turbines and steam turbine generating output in MW shall also be recorded if applicable. The test shall be conducted in accordance with a District approved source test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the District before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures. For gas turbines only the VOC test shall use the following test method: a) Stack gas samples are extracted into Summa canisters, maintaining a final canister pressure between 400 - 500 mm Hg absolute, b) Pressurization of Summa canisters is done with zero gas analyzed/certified to containing less than 0.05 ppmv total hydrocarbons as carbon, and c) Analysis of Summa canisters is per EPA Method TO-12 (with pre-concentration) and the temperature of the Summa canisters when extracting samples for analysis is not to be below 70 degrees F. The use of this alternative VOC test method is solely for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. Because the BACT level was set using data derived from various source test methods, this alternate method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results must be reported with two significant digits. The test shall be conducted when this equipment is operating at loads of 100, 75, and 50 (50 percent or the minimum compliant load achieved) percent of maximum load for the NOx, CO, VOC,and ammonia tests. The PM test shall be conducted when this equipment is operating at 100% of maximum load. All testing for this equipment shall be conducted in TRIPLICATE. The test shall be conducted when this equipment is operating at 100 percent of maximum load for the PM test. (SCAQMD D29-1)	The project owner shall submit the proposed protocol for the initial source tests 45 days prior to the proposed source test date to the District for approval and to the CPM for review. The project owner shall notify the District and CPM no later than 10 days prior to the proposed initial source test date and time. The project owner shall submit source test results no later than 60 days following the initial source test date to both the District and CPM.	04/11/07			x	**IEEC will comply with SCAQMD's testing requirements for the 7HA.01**

Condition No.	Sort Code	Description	Verification	COC Revision Date	Ongoing COC with Operations No Change Req'd for 7HA.01	Not Applicable for 7HA.01 Replacement	Applicable for 7HA.01 with Modification	Comment or Recommended Change
AQ-9	OPS	The test(s) shall be conducted at least once every three years. The test shall be conducted and the results submitted to the District within 60 days after the test date. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test. The test shall be conducted when the gas turbine is operating at 100 percent of maximum heat input._Testing for this equipment shall be conducted in TRIPLICATE. For gas turbines only the VOC test shall use the following test method: a) Stack gas samples are extracted into Summa canisters, maintaining a final canister pressure between 400 - 500 mm Hg absolute, b) Pressurization of Summa canisters is done with zero gas analyzed/certified to containing less than 0.05 ppmv total hydrocarbons as carbon, and c) Analysis of Summa canisters is per EPA Method TO-12 (with pre-concentration) and the temperature of the Summa canisters when extracting samples for analysis is not to be below 70 degrees F. The use of this alternative VOC test method is solely for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. Because the BACT level was set using data derived from various source test methods, this alternate method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results must be reported with two significant digits. The test shall be conducted to demonstrate compliance with the Rule 1303 concentration and/or monthly emissions limit. (SCAQMD D29-2)	The project owner shall submit the proposed protocol for the triennial source tests 45 days prior to the proposed source test date to the District for approval and to the CPM for review. The project owner shall notify the District and CPM no later than 10 days prior to the proposed source test date and time. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM.	04/11/07	x			
AQ-10	COMM	The operator shall conduct source test(s) for the pollutants identified below [NH3 emissions].The test shall be conducted and the results submitted to the District within 60 days after the test date. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test. The test(s) shall be conducted at least quarterly during the first twelve months of oper+C17ation and at least annually thereafter. The NOx concentration, as determined by the certified CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable or not yet certified, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period. The test shall be conducted to demonstrate compliance with the Rule 1303 concentration limit. (SCAQMD D29-3)	The project owner shall submit the proposed protocol for the ammonia slip source tests 30 days prior to the proposed source test date to the District for approval and to the CPM for review. The project owner shall notify the District and CPM no later than ten days prior to the proposed source test date and time. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM.	04/11/07	x			
AQ-11	COMM	The operator shall provide to the District a source test report (see **AQ-8**, **AQ-9**, and **AQ-10**) in accordance with the following specifications: Source test results shall be submitted to the District no later than 60 days after the source test was conducted. Emission data shall be expressed in terms of concentration (ppmv), corrected to 15 percent oxygen (dry basis), mass rate (lb/hr), and lbs/MM cubic feet. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF. All exhaust flow rates shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM). All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen. Source test results shall also include the oxygen levels in the exhaust, the fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted. (SCAQMD K40-1)	See verifications for Conditions AQ-8, AQ-9, and AQ-10.	04/11/07	x			
AQ-12	OPS	The operator shall not use natural gas containing the following specified compounds: Compound (H2S) Grains per 100 scf (Greater than 0.25) This concentration limit is an annual average based on monthly sample of natural gas composition or gas supplier documentation. (SCAQMD B61-1)	The project owner shall submit to the CPM and APCO turbine fuel data demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8).	06/22/05	x			

Condition No.	Sort Code	Description	Verification	COC Revision Date	Ongoing COC with Operations No Change Req'd for 7HA.01	Not Applicable for 7HA.01 Replacement	Applicable for 7HA.01 with Modification	Comment or Recommended Change
AQ-13	OPS	For the purpose of this condition, the limits shall be based on the emissions from each gas turbine. The operator shall calculate the emissions limits(s) by using monthly fuel use data and the following emission factors: PM10 2.93 lbs/mmscf, Sox 0.71 lbs/mmscf. The operator shall calculate the emission limit(s) by using monthly fuel use data and the following emission factors: VOC 1.79 lb/mmscf for normal operations, VOC 12.29 lb/mmscf for startups. The operator shall calculate the emissions limits(s) for CO, during the commissioning period, using fuel consumption data and the following emission factor: 22.19 lb/mmscf. The operator shall calculate the emission limit(s) for CO, after the commissioning period and prior to the CO CEMS certification, using fuel consumption data and the following emission factor: 4.48 lb/mmscf. The operator shall calculate the emissions limits(s) for CO, after the CO CEMS certification, based on readings from the certified CEMS. In the event the CO CEMS is not operating or the emissions exceed the valid upper range of the analyzer, the emissions shall be calculated in accordance with the approved CEMS plan. (SCAQMD A63-1)	The project owner shall submit to the CPM and APCO turbine emissions data demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8).	04/11/07	x			
AQ-14	COMM	The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s): Natural gas fuel use during the commissioning period. (SCAQMD K67-1)	The project owner shall make the site available for inspection of the commissioning period natural gas usage data by representatives of the District, CARB and the Commission.	06/22/05	x			
AQ-15	CONS	The operator shall install and maintain a CEMS to measure the following parameters: CO concentration in ppmv. Concentrations shall be corrected to15 percent oxygen on a dry basis. The CEMS will convert the actual CO concentrations to mass emission rates (lb/hr) and record the hourly emission rates on a continuous basis. The CEMS shall be installed and operated in accordance with an approved AQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from AQMD. The CEMS shall be installed and operated to measure CO concentration over a 15 minute averaging time period. The CEMS shall be installed and in operation no later than 90 days after initial startup of the turbine. Rule 218 testing shall be completed and submitted to the AQMD within 90 days of the conclusion of the turbine commissioning period. (SCAQMD D82-1)	The CEMS shall be installed and in operation after initial startup of the turbine. and Rule 218 testing shall be completed and submitted to the AQMD at the conclusion of the turbine commissioning period-. The project owner shall provide the CPM documentation of the Districts approval of the CEMS, within 15 days of its receipt. The project owner shall make the site available for inspection of the CEMS by representatives of the District, CARB and the Commission.	04/11/07	x			
AQ-16	CONS	The operator shall install and maintain a CEMS to measure the following parameters: NOx concentration is expressed in ppmv. Concentrations shall be corrected to 15 percent oxygen on a dry basis. The CEMS shall be installed and operating no later than 12 months after initial start-up of the turbine and shall comply with the requirements of Rule 2012. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3). Within two weeks of the turbine startup date, the operator shall provide written notification to the District of the exact date of start-up. The CEMS shall be installed and in operation within 90 days after initial startup of the turbine. Rule 2012 provisional RATA testing shall be completed and submitted to the AQMD within 90 days of the conclusion of the turbine commissioning period. (SCAQMD D82-2)	The CEMS shall be installed and in operation after initial startup of the turbine. Rule 2012 provisional RATA testing shall be completed and submitted to the AQMD at the conclusion of the turbine commissioning period. The project owner shall provide the CPM documentation of the Districts approval of the CEMS, within 15 days of its receipt. The project owner shall make the site available for inspection of the CEMS by representatives of the District, CARB and the Commission.	04/11/07		x		

Condition No.	Sort Code	Description	Verification	COC Revision Date	Ongoing COC with Operations No Change Req'd for 7HA.01	Not Applicable for 7HA.01 Replacement	Applicable for 7HA.01 with Modification	Comment or Recommended Change
AQ-17	COMM	The 68.26 lbs/mmscf NOx emission limit(s) shall only apply during the turbine commissioning period. (SCAQMD A99-1)	The project owner shall submit, commencing one month from the time of gas turbine first fire, a monthly commissioning status report throughout the duration of the commissioning phase that demonstrates compliance with this condition and the emission limits of Condition AQ-13. The monthly commissioning status report shall include criteria pollutant emission estimates for each commissioning activity and total commissioning emission estimates. The monthly commissioning status report shall be submitted to the CPM until the report includes the completion of the initial commissioning activities. The project owner shall make the site available for inspection of the commissioning records by representatives of the District, CARB and the Commission.	04/11/07			x	**IEEC will continue to use the existing certified CEMS for Unit 2. SCAQMD may develop new limits for testing and tuning requirements for the 7HA.01**
AQ-18	COMM	The operator shall operate and maintain this equipment according to the following requirements: The commissioning period shall not exceed 738 hours of operation for both turbines. Startup/shutdown time shall not exceed 4 hours per day per gas turbine, except for a cold startup and combustor-tuning activities, which shall not exceed 6 hours per day per gas turbine. A cold startup shall be defined as a startup of the gas turbine after 72 hours of non-operation. Combustor-tuning activities shall be defined as all testing, adjusting, tuning, and calibration activities recommended by the turbine manufacturer to ensure safe, reliable, and in-specification operation of the turbine. Startup/shutdown and combustor-tuning activity emissions shall not exceed 408 lbs/hr NOx and 800 lbs/hr CO averaged for the duration of the startup. The startup/shutdown and combustor-tuning activity emissions shall not exceed 803 lbs/event NOx and 2000 lbs/event CO. Monthly startup/shutdown time shall not exceed 31 hours. Shutdown time does not include non-operation time. The operator shall provide the AQMD with written notification of the initial startup date. Written records of commissioning, startups, shutdowns, and combustor- tuning activities shall be maintained and made available upon request from AQMD. (SCAQMD E193-2)	The project owner shall submit to the CPM the final commissioning status report as in Condition AQ-17. The project owner shall provide startup/shutdown and combustor-tuning activity occurrence, duration, and emissions data demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8). The project owner shall make the site available for inspection of the commissioning, start-up/shutdown, and combustor tuning activity records by representatives of the District, CARB and the Commission.	12/15/10	x			
AQ-19	OPS	The 7.36 lbs/mmscf NOx emission limit(s) shall only apply during the interim reporting period after the commissioning period to report RECLAIM emissions. (SCAQMD A99-3)	The project owner shall submit to the CPM and APCO turbine emissions data demonstrating compliance with this condition through the use of the required RECLAIM emission factor, as appropriate, as part of the Quarterly Operation Report (AQ-SC8).	04/11/07		x		
AQ-20	OPS	For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour. (SCAQMD E179-1) Condition **AQ-5** (SCAQMD D12-1) Condition **AQ-6** (SCAQMD D12-2)	See verifications for Conditions AQ-5 and AQ-6.	04/11/07	x			
AQ-21	OPS	For the purpose of the following condition number(s), "continuously record" shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that month. (SCAQMD E179-2) Condition **AQ-7** (SCAQMD D12-3)	See verification for Condition AQ-7.	04/11/07	x			

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AQ-22	OPS	The 2.0 ppmv NOx emission limit(s) is averaged over 1 hour at 15 percent oxygen, dry basis. The limit shall not apply to turbine commissioning, combustor-tuning activities, startup and shutdown periods. The limit shall not apply to the first fifteen 1-hour average NOx emissions above 2.0 ppmv, dry basis at 15% O2, in any rolling 12-month period for each combustion gas turbine provided that it meets all of the following requirements: A. This equipment operates under any one of the qualified conditions described below: a) Rapid combustion turbine load changes due to the following conditions: •Load changes initiated by the California ISO or a successor entity when the plant is operating under Automatic Generation Control; or •Activation of a plant automatic safety or equipment protection system which rapidly decreases turbine load b) The first two 1-hour reporting periods following the initiation/shutdown of the inlet air chilling system. Events as the result of technological limitation identified by the operator and approved in writing by the AQMD Executive Officer or his designees B. The 1-hour average NOx emissions above 2.0 ppmv, dry basis at 15% O2, did not occur as a result of operator neglect, improper operation or maintenance, or qualified breakdown under Rule 2004(i). C. The qualified operating conditions described in (A) above are recorded in the plant's operating log within 24 hours of the event, and in the CEMS by 5 p.m. the next business day following the qualified operating condition. The notations in the log and CEMS must describe the date and time of entry into the log/CEMS and the plant operating conditions responsible for NOx emissions exceeding the 2.0 ppmv 1-hour average limit. D. The 1-hour average NOx concentration for periods that result from a qualified operating condition does not exceed 25 ppmv, dry basis at 15 percent O2. All NOx emissions during these events shall be included in all calculations of hourly, daily, and annual mass emission rates as required by this permit. (SCAQMD A195-1)	The project owner shall submit to the CPM and APCO turbine CEMS emissions data demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8).	04/11/07	x			
AQ-23	OPS	The 3.0 ppmv CO emission limit(s) is averaged over 1 hour at 15 percent oxygen, dry basis. This limit shall not apply to turbine commissioning, combustor-tuning activities, startup and shutdown periods. (SCAQMD A195-2)	The project owner shall submit to the CPM and APCO turbine CEMS emissions data demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8).	04/11/07	x			
AQ-24	OPS	The 2.0 ppmv VOC emission limit(s) is averaged over 1 hour at 15 percent oxygen, dry basis. This limit shall not apply to turbine commissioning, combustor-tuning activities, startup and shutdown periods. (SCAQMD A195-3)	See verifications for Conditions AQ-8 and AQ-9.	04/11/07	x			
AQ-25	OPS	The 5 ppmv NH3 emissions limit(s) is averaged over 1 hour at 15 percent oxygen, dry basis. (SCAQMD A195-7)	See verification for Conditions AQ-8, AQ-10, and AQ-26.	04/11/07	x			
AQ-26	CONS	The operator shall operate and maintain this equipment according to the following requirements: The operator shall calculate and continuously record the NH3 slip concentration using the following: NH3 (ppmvd) = [a-b*(c*1.2)/1E6]*1E6/b, where a=NH3 injection rate (lb/hr)/17(lb/lb-mol), b=dry exhaust flow rate (scf/hr)/(385.5 scf/lb- mol), c=change in measured NOx across the SCR, ppmvd at 15 percent O2. The operator shall install a NOx analyzer to measure the SCR inlet NOx ppm accurate to within +/- 5 percent calibrated at least once every 12 months. The operator shall use the method described above or another alternative method approved by the Executive Officer. The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information determination without corroborative data using an approved reference method for the determination of ammonia. The ammonia slip calculation procedure shall be in-effect no later than 90 days after initial startup of the turbine. (SCAQMD E193-4)	The project owner shall provide the CPM documentation of the District's approval. The project owner shall make the site available for inspection of the monitoring records by representatives of the District, CARB and the Commission. The project owner shall submit to the CPM emissions data generated by the calculation procedure as part of the Quarterly Operation Report (**AQ-SC8**).	04/11/07	x			

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AQ-27	OPS	This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase. To comply with this condition, the operator shall prior to the first compliance year hold a minimum NOx RTCs of 165,612 lbs for the initial gas turbine plus 152,218 lbs for the second gas turbine. This condition shall apply during the first twelve months of operation, commencing with the initial operation of each gas turbine. To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the first compliance year, hold a minimum NOx RTCs of 158,943 lbs for each gas turbine. In accordance with Rule 2005(f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the first compliance year. (SCAQMD I296-1 and I296-2)+C41	The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8).	04/11/07	x			
AQ-28	COMM	For the purpose of determining compliance with District Rule 475, combustion contaminant emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time. (SCAQMD A327-1)	See verifications for Conditions AQ-8 and AQ-9.	06/22/05	x			
Conditions AQ-29 through AQ-47 apply to Auxiliary Boiler and SCR								
AQ-29	CONS	The operator shall install and maintain a flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH3). The operator shall also install and maintain a device to continuously record the parameter being measured. The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. (SCAQMD D12-1)	The project owner shall make the site available for inspection of the ammonia flow meter and ammonia flow records by representatives of the District, CARB and the Commission.	06/22/05	x			
AQ-30	CONS	The operator shall install and maintain a temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor. The operator shall also install and maintain a device to continuously record the parameter being measured. The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. (SCAQMD D12-2)	The project owner shall make the site available for inspection of the temperature gauge on the inlet to the SCR and the continuous temperature records by representatives of the District, CARB and the Commission.	06/22/05	x			
AQ-31	CONS	The operator shall install and maintain a pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column. The operator shall also install and maintain a device to continuously record the parameter being measured. The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. (SCAQMD D12-3)	The project owner shall make the site available for inspection of the SCR catalyst bed differential pressure gauge and the differential pressure records by representatives of the District, CARB and the Commission.	06/22/05	x			

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AQ-32	COMM	The test shall be conducted after District approval of the source test protocol, but no later than 180 days after initial start-up. The District shall be notified of the date and time of the test at least 10 days prior to the test. The test shall be conducted after District approval of the source test protocol, but no later than 180 days after initial start-up. The District shall be notified of the date and time of the test at least 10 days prior to the test. The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH) and the flue gas flow rate. The test shall be conducted in accordance with a District approved source test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the District before the test commences. The test protocol shall include the proposed operating conditions of the auxiliary boiler during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures. The test shall be conducted when this equipment is operating at 100 percent of maximum load for the NOx, CO, VOC and ammonia tests. (SCAQMD D29-4).	The project owner shall submit the proposed protocol for the initial source tests 45 days prior to the proposed source test date to the District for approval and to the CPM for review. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM. The project owner shall notify the District and CPM no later than 10 days prior to the proposed initial source test date and time.	04/11/07				
AQ-33	COMM	The operator shall conduct source test(s) for the pollutant(s) identified below. Pollutant(s) to be tested Required Test Method(s) Averaging Time Test Location NH3 emissions District Method 207.1 and 5.3 or EPA Method 17 1 hour Outlet of the SCR The test shall be conducted and the results submitted to the District within 60 days after the test date. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test. The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the certified CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable or not yet certified, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.The test shall be conducted to demonstrate compliance with the Rule 1303 concentration limit. (SCAQMD D29-3)	The project owner shall submit the proposed protocol for the source tests 30 days prior to the proposed source test date to the District for approval and to the CPM for review. The project owner shall notify the District and CPM no later than ten days prior to the proposed source test date and time. The project owner shall submit source test results no later than 45 days following the source test date to both the District and CPM.	06/22/05				
AQ-34	COMM	The operator shall provide to the District a source test report (see AQ-32 and AQ-33) in accordance with the following specifications: -Source test results shall be submitted to the District no later than 60 days after the source test was conducted. -Emission data shall be expressed in terms of concentration (ppmv), corrected to 3 percent oxygen (dry basis), mass rate (lbs/hr), and lbs/MM cubic feet. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF. -All exhaust flow rates shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM). -All moisture concentration shall be expressed in terms of percent corrected to 3 percent oxygen. Source test results shall also include the oxygen levels in the exhaust, the fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted. (SCAQMD K40-2	See verifications for Conditions AQ-32 and AQ-33	06/22/05			x	**IEEC will comply with SCAQMD's testing requirements for the 7HA.01**
AQ-35	OPS	The operator shall limit the fuel usage to no more than 29.24 mmscf per month. To comply with this condition, the operator shall install and maintain a non-resettable totalizing fuel meter to accurately indicate the fuel usage of the auxiliary boiler. (SCAQMD C1-2)	The project owner shall submit to the CPM and APCO the auxiliary boiler operations data demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8). The project owner shall make the auxiliary boiler available for inspection by representatives of the District, CARB and the Commission upon request.	04/11/07	x			

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AQ-36	OPS	The operator shall calculate the emission **limit(s)** by using monthly fuel use data and the following emission factors: CO 36.92 lb/mmscf, PM10 7.26 lbs/mmscf, VOC 4.22 lbs/mmscf, SOx 0.71 lbs/mmscf. The operator shall calculate the emission **limit(s)** for CO, after the CO CEMS certification, based on readings from the certified CEMS. In the event the CO CEMS is not operating or the emissions exceed the valid upper range of the analyzer, the emissions shall be calculated in accordance with the approved CEMS plan. (SCAQMD A63-2)	The project owner shall submit to the CPM and APCO boiler emissions data demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8).	04/11/07	x			
AQ-37	CONS	The operator shall install and maintain a CEMS to measure the following parameters: • CO concentration in ppmv. Concentrations shall be corrected to 3 percent oxygen on a dry basis. The CEMS will convert the actual CO concentrations to mass emission rates (lbs/hr) and record the hourly emission rates on a continuous basis. The CEMS shall be installed and operated, in accordance with an approved AQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from AQMD. The CEMS shall be installed and operated to measure CO concentration over a 15 minute averaging time period. The CEMS shall be installed and operating no later than 90 days after initial startup of the boiler. (SCAQMD D82-3)	The project owner shall provide the CPM documentation of the Districts approval of the CEMS, within 15 days of its receipt. The project owner shall make the site available for inspection of the CEMS by representatives of the District, CARB and the Commission.	06/22/05	x			
AQ-38	CONS	The operator shall install and maintain a CEMS to measure the following parameters: • NOx concentration is expressed in ppmv. Concentrations shall be corrected to 3 percent oxygen on a dry basis. The CEMS shall be installed and operating no later than 12 months after initial start-up of the boiler and shall comply with the requirements of Rule 2012. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3). Within two weeks of the boiler startup date, the operator shall provide written notification to the District of the exact date of start-up. The CEMS shall be in operation and Rule 2012 provisional RATA testing submitted to the AQMD within 90 days of the conclusion of the boiler commissioning period. The CEMS shall be installed and operating no later than 90 days after initial startup of the boiler. (SCAQMD D82-4)	The project owner shall provide the CPM documentation of the Districts approval of the CEMS, within 15 days of its receipt. The project owner shall make the site available for inspection of the CEMS by representatives of the District, CARB and the Commission.	04/11/07	x			
AQ-39	OPS	The 8.49 lbs/mmscf NOx emission limit(s) shall only apply after the installation and operation of the SCR catalyst during the interim reporting period to report RECLAIM emissions. (SCAQMD A99-2) The 100.67 lbs/mmscf NOx emission limit(s) shall only apply prior to the installation of the SCR catalyst during the interim reporting period to report RECLAIM emissions. (SCAQMD A99-4)	The project owner shall submit to the CPM and APCO auxiliary boiler emissions data demonstrating compliance with this condition through the use of the required RECLAIM emission factor, as appropriate, as part of the Quarterly Operation Report (AQ-SC8).	12/15/10	x			
AQ-40	COMM	For the purpose of the following conditions number(s), continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour. (SCAQMD E179-1) Condition AQ-29 (SCAQMD D12-1) Condition AQ-30 (SCAQMD D12-2)	See verifications for Conditions AQ-29 and AQ-30.	04/11/07	x			
AQ-41	COMM	For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that month. (SCAQMD E179-2) Condition AQ-31 (SCAQMD D12-3)	See verification for Condition AQ-31.	04/11/07	x			

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AQ-42	OPS	The 7 ppmv NOx emission limit(s) is averaged over one hour at 3 percent oxygen, dry basis. This limit shall not apply during the initial auxiliary boiler commissioning period not to exceed 200 hours or until the SCR catalyst is installed and operational, whichever occurs first. This limit shall not apply during startup and shutdown periods. Startup shall not exceed 75 minutes per occurrence and shutdown shall not exceed 30 minutes per occurrence. There shall be no more than one startup and one shutdown per day. (SCAQMD A195-4)	The project owner shall submit to the CPM and APCO auxiliary boiler CEMS emissions data demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8).	12/15/10	x			
AQ-43	OPS	The 7 ppmv NOx emission limit(s) is averaged over one hour at 3 percent oxygen, dry basis. (SCAQMD A195-5)	The project owner shall submit to the CPM and APCO auxiliary boiler CEMS emissions data demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8).	04/11/07	x			
AQ-44	COMM	The 10 ppmv VOC emission limit(s) is averaged over 1 hour at 3 percent oxygen, dry basis. (SCAQMD A195-6)	See verification for Condition AQ-32.	04/11/07	x			
AQ-45	COMM	The 5 ppmv NH3 emission limit(s) is averaged over 1 hour at 3 percent oxygen, dry basis. The limit shall not apply during the auxiliary boiler D3 startup process when the SCR catalyst temperature is below 480 degree F. The limit shall not apply during the auxiliary boiler D3 boiler shutdowns. (SCAQMD A195-8)	See verification for Conditions AQ-32, AQ-33, and AQ-46.	12/15/10	x			
AQ-46	OPS	The operator shall operate and maintain this equipment according to the following requirements: The operator shall calculate and continuously record the NH3 slip concentration using the following: NH3 (ppmvd) = [a-b*(c*1.2)/1E6]*1E6/b, where a=NH3 injection rate (lb/hr)/17(lb/lb-mol), b=dry exhaust flow rate (scf/hr)/(385.5 scf/lb- mol), c=change in measured NOx across the SCR, ppmvd at 3 percent O2. The operator shall install a NOx analyzer to measure the SCR inlet NOx ppm accurate to within +/- 5 percent calibrated at least once every 12 months. The operator shall use the method described above or another alternative method approved by the Executive Officer. The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information determination without corroborative data using an approved reference method for the determination of ammonia. The ammonia slip calculation procedure shall be in-effect no later than 90 days after initial startup of the boiler. (SCAQMD E193-5)	The project owner shall provide the CPM documentation of the District's approval of The project owner shall make the site available for inspection of the monitoring records by representatives of the District, CARB and the Commission. The project owner shall submit to the CPM emissions data generated by the calculation procedure as part of the Quarterly Operation Report (**AQ-SC8**).	04/11/07	x			
AQ-47	OPS	This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase. To comply with this condition, the operator shall prior to the first compliance year hold a minimum NOx RTCs of 790 lbs. This condition shall apply during the first twelve months of operation. To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the first compliance year, hold a minimum NOx RTCs of 790 lbs. In accordance with Rule 2005(f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the first compliance year. (SCAQMD I296-3)	The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8).	04/11/07	x			
Conditions AQ-48 through AQ-53 apply to the Emergency Generators and Fire Pump Engine.								

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AQ-48	OPS	Emergency Generator Engines: The operator shall limit the operating time of each engine to no more than 200 hours per year. The 200 hours annual limit includes no more than 50 hours in any one year for maintenance and testing purposes. (SCAQMD C1-1) Emergency Fire Pump Engine: The operator shall limit the operating time to no more than 50 hours in any one year. (SCAQMD C1-3)	The project owner shall submit to the CPM and APCO the emergency generator and fire pump IC engines operations data demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8).	12/15/10	x			
AQ-49	CONS	The operator shall install and maintain a non-resettable elapsed time meter to accurately indicate the elapsed operating time of each engine. (SCAQMD D12-4)	The project owner shall make the emergency generator and fire pump engines available for inspection by representatives of the District, CARB and the Commission upon request.	06/22/05	x			
AQ-50	CONS	The operator shall install and maintain a non-resettable totalizingfuel meter to accurately indicate the fuel usage of each engine. (SCAQMD D12-5)	The project owner shall make the emergency generator and fire pump engines available for inspection by representatives of the District, CARB and the Commission upon request.	04/11/07	x			
AQ-51	OPS	The emergency generator engines shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase. To comply with this condition, the operator shall prior to the first compliance year hold a minimum NOx RTCs of 1,946 lbs for each engine. This condition shall apply during the first twelve months of operation. To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the first compliance year, hold a minimum NOx RTCs of 7,784 lbs for each engine. In accordance with Rule 2005(f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the first compliance year. (SCAQMD I296-4)	The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8).	12/15/10	x			
AQ-52	OPS	The fire pump engine shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase. To comply with this condition, the operator shall prior to the first compliance year hold a minimum NOx RTCs of 172 lbs. This condition shall apply during the first twelve months of operation. To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the first compliance year, hold a minimum NOx RTCs of 172 lbs. In accordance with Rule 2005(f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the first compliance year. (SCAQMD I296-5)	The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8).	06/22/05	x			
AQ-53	OPS	The operator shall keep records, in a manner approved by the District, for the following parameters or items: • Date of operation, the elapsed time, in hours, and the reason for operation. (SCAQMD K67-2)	The project owner shall make the emergency generator and fire pump engine records available for inspection by representatives of the District, CARB and the Commission upon request.	04/11/07	x			
AQ-54	CONS	The operator shall vent this equipment, during filling, only to the vessel from which it is being filled. (SCAQMD E144-1)	The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission upon request.	04/11/07	x			
AQ-55	CONS	The operator shall install and maintain a pressure relief valve with a minimum pressure set at 25 psig. (SCAQMD C157-1)	The project owner shall make the ammonia tank pressure relief valve and its specifications available for inspection by representatives of the District, CARB and the Commission upon request.	04/11/07	x			

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AQ-56	CONS	The operator shall be subject to the applicable requirements of District Rule 1171 for VOC control from Solvent Cleaning Operations. This requirement shall apply to Rule 219 Exempted Cleaning Equipment. (SCAQMD H23-1)	The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission upon request.	06/22/05	x			
AQ-57	CONS	The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s): • For architectural applications where no thinners, reducers, or other VOC containing materials are added, maintain semi-annual records for all coating consisting of (a) coating type, (b) VOC content as supplied in grams per liter (g/l) of materials for low-solids coatings, (c) VOC content as supplied in g/l of coating, less water and exempt solvent, for other coatings. • For architectural applications where thinners, reducers, or other VOC containing materials are added, maintain daily records for each coating consisting of (a) coating type, (b) VOC content as applied in grams per liter (g/l) of materials used for low-solids coatings, (c) VOC content as applied in g/l of coating, less water and exempt solvent, for other coatings. • This requirement shall apply to Rule 219 Exempted Coating Equipment. (SCAQMD K67-3)	The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission upon request.	06/22/05	x			
AQ-58	OPS	The operator shall restrict the operation of the gas turbines and auxiliary boiler according to the following requirements: • The calendar daily cumulative operating hours for both gas turbines (D1 and D2) and the auxiliary boiler (D3) shall not exceed 60 hours per day. The operating hours shall be recorded and maintained using an automated data acquisition system. The operating hours shall be determined from the RECLAIM certified NOx CEMS accurate to the nearest 15-min operating period. • The operator shall maintain daily records summarizing daily operating hours of each of the following equipment – gas turbine D1, gas turbine D2, and auxiliary boiler D3 for at least 5 years and made available to AQMD upon request. (SCAQMD E193-6)	The project owner shall submit to the CPM and APCO turbine and boiler operating data demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8). The project owner shall make the records available for inspection by representatives of the District, CARB and the Commission upon request.	04/11/07	x			
AQ-SC1	PC	The project owner shall fund all expenses for an on-site Air Quality Construction Mitigation Manager (AQCMM) who shall be responsible for maintaining compliance with conditions **AQ-SC2** through **AQ-SC6** for the entire project site and linear facility construction. The on-site AQCMM may delegate responsibilities identified in Conditions **AQ-SC1** through **AQ-SC6** to one or more air quality construction mitigation monitors. The on-site AQCMM shall have access to areas of construction of the project site and linear facilities, and shall have the authority to appeal to the CPM to have the CPM stop any or all construction activities as warranted by applicable construction mitigation conditions.The AQCMM may have other responsibilities in addition to those described in this condition. The on-site AQCMM shall not be terminated without written consent of CPM.	At least 60 days prior to the start of ground disturbance, the project owner shall submit to the CPM, for approval, the name and contact information for the on-site AQCMM and air quality construction mitigation monitors.	04/11/07		x		
AQ-SC2	PC	The project owner shall provide a construction mitigation plan, for approval, which shows the steps that will be taken, and reporting requirements, to ensure compliance with conditions AQ-SC3 and AQSC4.	At least 60 days prior to start any ground disturbance, the project owner shall submit to the CPM, for approval, the construction mitigation plan. The CPM will notify the project owner of any necessary modifications to the plan within 30 days from the date of receipt. Otherwise, the plan shall be deemed approved.	12/22/03		x		

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AQ-SC3	CONS	The on-site AQCMM shall submit to the CPM, in the Monthly Compliance Report (MCR), a construction mitigation report that demonstrates compliance with the following mitigation measures: a) All unpaved roads and disturbed areas in the project and linear construction sites shall be watered until sufficiently wet for every four hours of construction activities, or until sufficiently wet to comply with the dust mitigation objectives of Condition AQ-SC4. The frequency of watering can be reduced or eliminated during periods of precipitation. b) No vehicle shall exceed 15 miles per hour within the construction site. c) The construction site entrances shall be posted with visible speed limit signs. d) All construction equipment vehicle tires shall be washed or cleaned free of dirt prior to entering paved roadways. e) Gravel ramps of at least 20 feet in length must be provided at the tire washing/cleaning station. f) All entrances to the construction site shall be graveled or treated with water or dust soil stabilization compounds. g) Construction vehicles must enter the construction site through the treated entrance roadways. h) Construction areas adjacent to any paved roadway shall be provided with sandbags to prevent run-off to the roadway. i) All paved roads within the construction site shall be swept twice daily when construction activity occurs. j) At least the first 500 feet of any public roadway exiting from the construction site shall be swept twice daily when construction activity occurs. k) All soil storage piles and disturbed areas that remain inactive for longer than 10 days shall be covered, or be treated with appropriate dust suppressant compounds. l) All vehicles that are used to transport solid bulk material on public roadways and that have potential to cause visible emissions shall be provided with a cover, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to provide at least one foot of freeboard. m) Wind erosion control techniques, such as windbreaks, water, chemical dust suppressants, and vegetation, shall be used on all construction areas that may be disturbed. Any windbreaks used shall remain in place until the soil is stabilized or permanently covered with vegetation. n) Any construction activities that may cause fugitive dust in excess of the visible emission limits specified in Condition AQ-SC4 shall cease when the wind exceeds 25 miles per hour unless water, chemical dust suppressant, or other measures have been applied to reduce dust to the limits set forth in AQ-SC4.	In the MCR, the project owner shall provide the CPM a copy of the construction mitigation report and any diesel fuel purchase records, which demonstrate compliance with condition AQ-SC3.	12/22/03		x		
AQ-SC4	CONS	No construction activities are allowed to cause visible dust emissions at or beyond the project site fenced property boundary or any adjacent lands owned by the applicant. No construction activities are allowed to cause visible dust plumes that exceed 20 percent opacity at any location on the construction site. No construction activities are allowed to cause any visible dust plume in excess of 200 feet beyond the centerline of the construction of linear facilities.	The on-site AQCMM shall conduct a visible emission evaluation at the construction site fence line, or 200 feet from the center of construction activities at the linear facilities, each time he/she sees excessive fugitive dust from the construction or linear facility site. The records of the visible emission evaluations shall be maintained at the construction site and shall be provided to the CPM in the MCR.	12/22/03		x		
AQ-SC5	N/A	Condition Deleted.	Condition Deleted.	12/22/03				
AQ-SC6	CONS	During site mobilization, ground disturbance, and grading activities, the project owner shall limit the fugitive dust causing activities (i.e. scraping, grading, trenching, or other earth moving activities) to no more than a twelve-hour per day schedule as provided in Condition NOISE-8.	The project owner shall provide records of compliance as part of the MCR.	12/22/03		x		
AQ-SC7	CONS	The project owner shall submit to the CPM for review and approval any modification proposed by the project owner to any project air permit. The project owner shall submit to the CPM any modification to any permit proposed by the District or EPA, and any revised permit issued by the District or EPA, for the project.	The project owner shall submit any proposed air permit modification to the CPM within five working days of its submittal either by 1) the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all modified air permits to the CPM within 15 days of receipt.	12/22/03	x			

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AQ-SC8	OPS	The project owner shall submit to the CPM Quarterly Operation Reports, no later than 30 days following the end of each calendar quarter, that include operational and emissions information as necessary to demonstrate compliance with Conditions **AQ-SC11**, **AQ-SC12**, **AQ-SC14**, **AQ-SC15**, **AQ-SC17**,and **AQ-1** through **AQ-58**, as applicable. The Quarterly Operation Report will specifically note or highlight incidences of noncompliance.	The project owner shall submit the Quarterly Operation Reports to the CPM no later than 30 days following the end of each calendar quarter.	04/11/07	x			
AQ-SC9	PC	The project owner shall provide emission reduction credits to offset turbine, auxiliary boiler, and standby/emergency equipment NOx, CO, VOC, SOx, and PM10 emissions in the form and amount required by the District. RECLAIM Trading Credits (RTCs) shall be provided for NOx as necessary to demonstrate compliance with **AQ-27, AQ-47, AQ-51, and AQ-52**. Emission reduction credits (ERCs) shall be provided for CO (822 lb/day, includes offset ratio of 1.2) and VOC (307 lb/day, includes offset ratio of 1.2). Emission reduction credits for SOx (91 lb/day) and PM10 (379 lb/day) shall be obtained from the SCAQMD Priority Reserve.	The project owner shall submit to the CPM records showing that the project's offset requirements have been met 15 days prior to initiating construction for Priority Reserve credits and RTCs, and 30 days prior to turbine first fire for traditional ERCs. If the CPM approves a substitution or modification to the list of ERCs, the CPM shall file a statement of the approval with the project owner and commission docket. The CPM shall maintain an updated list of approved ERCs for the project.	04/11/07		x		
AQ-SC10	COMM	If the project owner uses Priority Reserve Credits to satisfy District ERC requirements, the project owner shall comply with all applicable requirements of SCAQMD Rule 1309.1 governing the use of such credits. Note: Nothing in this condition shall waive the requirements of Section 1720.3 of the Commission's regulations.	Within 15 days of becoming operational, the project owner shall submit to the District and CPM documentation substantiating that the requirements of SCAQMD Rule 1309.1 and Section 1720.3 of the Commission's regulations have been met.	06/22/05		x		
AQ-SC11	OPS	The project owner shall perform quarterly cooling tower recirculating water quality testing for each cooling tower, or shall provide for continuous monitoring of conductivity as an indicator, for total dissolved solids content. The project owner shall also provide a flow meters to determine the daily cooling tower circulating water flow for each cooling tower.	The project owner shall submit to the CPM cooling tower recirculating water quality tests or a summary of continuous monitoring results and daily recirculating water flow in the Quarterly Operation Report (AQ-SC8). If the project owner uses continuous monitoring of conductivity as an indicator for total dissolved solids content, the project owner shall submit data supporting the calibration of the conductivity meter and the correlation with total dissolved solids content at least once each year in a Quarterly Operation Report (AQ-SC8).	06/22/05	x			
AQ-SC12	OPS	The cooling tower daily PM10 emissions shall be limited to 42 lb/day per cooling tower. Each cooling tower shall be equipped with a drift eliminator to control the drift fraction to 0.0005 percent of the circulating water flow. The project owner shall estimate daily PM10 emissions from Each cooling tower using the water quality testing data or continuous monitoring data and daily circulating water flow data collected on a quarterly basis.	The project owner shall submit to the CPM daily cooling tower PM10 emission estimates in the Quarterly Operation Report (AQ-SC8).	06/22/05	x			
AQ-SC13	COMM	The project owner shall minimize emissions of carbon monoxide and nitrogen oxides from the gas turbines to the maximum extent possible during the commissioning period. During the commissioning period, the project owner shall limit the combined CO emission rate for the two gas turbines to 794.2 lb/hr (777 lb/hr commissioning plus 17.2 lb/hr baseload) and limit the combined NOx emission rate for the two gas turbines to 605.8 816 lb/hr (587 lb/hr commissioning plus 18.8 lb/hr baseload 408 lb/hr for each).	See the verification for Condition AQ-17.	04/11/07		x		
AQ-SC14	OPS	The project owner shall limit emissions during startup periods. During startup periods, the project owner shall limit the combined CO emission rate for the two gas turbines to 190 1600 lb/hr (95 800 lb/hr for each turbine) and limit the combined NOx emission rate for the two gas turbines to 816 lb/hr (408 lb/hr for each turbine).	See the verification for Condition AQ-18.	12/15/10	x			
AQ-SC15	OPS	The gas turbines shall be fired on natural gas that results in emissions of less than 1.83 lb/hr SOx for each gas turbine, averaged over three hours.	The project owner shall compile hourly SOx emissions data for each gas turbine. The hourly emission data shall be calculated using the emission factor specified in Condition AQ-13. The emissions data shall be submitted to the CPM in the Quarterly Operation Report (AQ-SC8).	04/11/07	x			

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AQ-SC16	OPS	The project owner shall install and operate the equipment so that it does not exceed the emission limits set forth in the Equipment Description portion of Section H of the facility permit issued by the District. The current Equipment Description, as shown in the May 2005 Determination of Compliance July 1, 2006 Permit to Construct, is attached as Attachment Air Quality 1 – AQ-SC16, Equipment Description.	The project owner shall submit to the CPM emissions data demonstrating compliance with this condition as part of the Quarterly Operation Report (AQ-SC8). The project owner shall submit to the CPM all permit changes, whether initiated by the project owner or the District, pursuant to Condition AQ-SC7.; updates to table: Attachment Air Quality 1 – AQ-SC16, Equipment Description EQUIPMENT DESCRIPTION Section H of the facility permit: Permit to Construct and temporary Permit to Operate	04/11/07; 12/15/10			x	**SCAQMD will provide updated equipment description for CEC to incorporate that will reflect the 7HA.01 changes for Unit 2.**
~~AQ-SC17~~	~~OPS~~	~~If the Project owner does not voluntarily participate in the California Climate Action Registry then the Project owner shall report to the CPM the quantity of CO_2 emitted on an annual basis as a direct result of facility electrictiy production.~~	~~Any CO_2 emissions that are reported by the project owner to the California Climate Action Registry or pursuant to this condition shall be reported to the CPM once each year as part of the fourth Quarterly Air Quality Reports required by Condition of Certification AQ-SC8.~~	~~6/22/05;~~ 6/27/2012	x			**On June 27, 2012, CEC stated that AQ-SC17 was no longer necessary and that CEC would formally delete this COC.**
AQ-SC18 NEW	**OPS**	**Upon completion of the turbine replacement project, in which the existing Unit 2 GE 7H gas turbine is replaced with the new GE 7HA.01 gas turbine, the owner or operator shall monitor the emissions of regulated NSR pollutants (i.e., NOx, PM10, CO and SO2) that could increase as a result of the project and that is emitted by Unit 2. The owner or operator shall calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the turbine replacement.**	**The project owner shall submit to the CPM and USEPA, a report within 60 days after the end of each year during which records must be generated under 40 CFR 51.21 (r) (6) (iii) setting out the unit's annual emissions during the calendar year that preceded submission of the report**.	**NEW**			x	**IEEC proposes a new COC to comply with the reporting requirements per 40 CFR 51.21 (r) (6) (iii)**

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BIO-1	PC	The project owner shall submit the resume, including contact information, of the proposed Designated Biologist to the CPM for approval prior to the start of any site or related facilities mobilization	The project owner shall submit the specified information at least 60 days prior to the start of any site or related facilities mobilization. Site or related facilities mobilization shall not commence until an approved Designated Biologist is available to be on site. The Designated Biologist must meet the following minimum qualifications: 1. Bachelor's Degree in biological sciences, zoology, botany, ecology, or a closely related field; 2. Three years of experience in field biology or current certification of a nationally recognized biological society such as The Ecological Society of America or The Wildlife Society; and 3. At least one year of field experience with biological resources found in or near the project area. If a Designated Biologist needs to be replaced, the specified information of the proposed replacement must be submitted to the CPM at least 10 working days prior to the termination or release of the preceding Designated Biologist. In an emergency, the project owner shall immediately notify the CPM to discuss the qualifications and approval of a short-term replacement while a permanent Designated Biologist is proposed to the CPM for consideration.	12/22/03		x		
BIO-2	CONS	The Designated Biologist shall perform the following during any site or related facilities mobilization, ground disturbance, grading, construction, operation, and closure activities. The Designated Biologist may be assisted by a Biological Monitor(s). 1. Advise the project owner's Construction Manager and Operation Manager, supervising construction engineer and operations engineer on the implementation of the biological resources Conditions of Certification; 2. Be available to supervise or conduct mitigation, monitoring, and other biological resources compliance efforts, particularly in areas requiring avoidance or containing sensitive biological resources such as wetlands and special status species or their habitat; 3. Clearly mark sensitive biological resource areas and inspect these areas at appropriate intervals for compliance with regulatory terms and conditions; 4. Prior to construction commencing each day, inspect active construction areas where animals may have become trapped. At the end of the day, inspect for the installation of structures that prevent entrapment or allow escape during periods of construction inactivity. Periodically inspect areas with high vehicle activity (parking lots) for animals in harms way; 5. Notify the project owner and the CPM of any non-compliance with any biological resources Condition of Certification; and 6. Respond directly to inquiries of the CPM regarding biological resource issues.	The Designated Biologist shall maintain written records of the tasks described above; summaries of these records shall be submitted in the Monthly Compliance Reports (MCRs). The Biological Monitor(s) shall be approved by the CPM. Biological Monitor(s) training shall include familiarity with the Conditions of Certification and the monitoring procedures established in the BRMIMP. During project operation, the Designated Biologist shall submit summaries of the tasks described above in the Annual Compliance Report.	12/22/03	x	x		

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BIO-3	CONS	The project owner's Construction Manager and Operation Manager shall act on the advice of the Designated Biologist or Biological Monitor(s) to ensure conformance with the biological resources Conditions of Certification. If required by the Designated Biologist or Biological Monitor(s), the project owner's Construction Manager or Operation Manager shall halt all site mobilization, ground disturbance, grading, construction, and operation activities in areas specified by the Designated Biologist as sensitive or which may affect a sensitive area or sensitive species. The Designated Biologist and Biological Monitor(s) shall: 1. Require a halt to all activities in any area when it is determined that there would be an adverse impact to sensitive biological resources if the activities continued; 2. Inform the project owner, the Construction Manager and the Operation Manager hen to resume activities; and 3. Notify the CPM if there is a halt of any activities, and advise the CPM of any corrective actions that have been taken, or will be instituted, as a result of the halt.	The Designated Biologist must notify the CPM and the project owner immediately (and no later than the following morning of the incident, or Monday morning in the case of a weekend) of any non-compliance or a halt of any site mobilization, ground disturbance, grading, construction, and operation activities. The project owner shall notify the CPM of the circumstances and actions being taken to resolve the problem. Whenever corrective action is taken by the project owner, a determination of success or failure will be made by the CPM within five working days after receipt of notice that corrective action is completed, or the project owner will be notified by the CPM that coordination with other agencies will require additional time before a determination can be made.	12/22/03		x		
BIO-4	PC	The project owner shall develop and implement a CPM approved Worker Environmental Awareness Program (WEAP) in which each of its employees, as well as employees of contractors and subcontractors who work on the project site or any related facilities during site mobilization, ground disturbance, grading, construction, operation and closure are informed about sensitive biological resources associated with the project. The training may be in the form of a video if administered by a person approved by the Designated Biologist. The WEAP must: 1. Be developed by or in consultation with the Designated Biologist and consist of an on-site or training center presentation in which supporting written material is made available to all participants; 2. Discuss the locations and types of sensitive biological resources on the project site and adjacent areas; 3. Present the reasons for protecting these resources; 4. Present the meaning of various temporary and permanent habitat protection measures; 5. Identify whom to contact if there are further comments and questions about the material discussed in the program; and 6. Include a training acknowledgment form to be signed by each worker indicating that they received training and shall abide by the guidelines. The specific program can be administered by a competent individual(s) acceptable to the Designated Biologist.	At least 60 days prior to the start of any site or related facilities mobilization, the project owner shall submit to the CPM two copies of the WEAP and all supporting written materials prepared or reviewed by the Designated Biologist and a resume of the person(s) administering the program. The project owner shall submit in the MCR the number of persons who have completed the training in the prior month and a running total of all persons who have completed the training to date. The signed training acknowledgement forms from construction shall be kept on file by the project owner for a period of at least six months after the start of commercial operation. During project operation, signed statements for active project operational personnel shall be kept on file for six months following the termination of an individual's employment.	12/22/03		x		

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BIO-5	CONS	The project owner shall submit two copies of the proposed Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP) to the CPM for review and approval and to CDFG and USFWS for review and comment prior to the start of any site or related facilities mobilization and shall implement the measures identified in the approved BRMIMP. The final BRMIMP shall identify: 1. All biological resources mitigation, monitoring, and compliance measures proposed and agreed to by the project owner; 2. All Biological Resources Conditions of Certification identified in the Commission's Final Decision; 3. All biological resource mitigation, monitoring and compliance measures required in federal agency terms and conditions, such as those provided in the USACE permit and as a result of informal consultation between the project owner and the USFWS; 4. All biological resources mitigation, monitoring and compliance measures required in other state agency terms and conditions, such as those provided in the RWQCB permit; 5. All biological resources mitigation, monitoring and compliance measures required in local agency permits, such as site grading, noise, lighting, and landscaping requirements; 6. All incidental take minimization measures as provided in the Stephens' kangaroo rat HCP or as specified by the Stephens' kangaroo rat Habitat Conservation Agency; 7. All sensitive biological resources to be impacted, avoided, or mitigated by project construction, operation and closure; 8. All required mitigation measures for each sensitive biological resource; 9. Required habitat compensation strategy, including provisions for acquisition, enhancement, and management for any temporary and permanent loss of sensitive biological resources; 10.A detailed description of measures that will be taken to avoid or mitigate temporary disturbances from construction activities; 11.All locations on a map, at an approved scale, of sensitive biological resource areas subject to disturbance and areas requiring temporary protection and avoidance during construction; 12.Aerial photographs, at an approved scale, of all areas to be disturbed during project construction activities - one set prior to any site or related facilities mobilization disturbance and one set subsequent to completion of mitigation measures. Include planned timing of aerial photography and a description of why times/dates were chosen; 13.Duration for each type of monitoring and a description of monitoring	The project owner shall submit the specified document at least 60 days prior to start of any site or related facilities mobilization. The CPM, in consultation with the CDFG, the USFWS and any other appropriate agencies, shall determine the BRMIMP's acceptability within 45 days of receipt. If there are any permits that have not yet been received when the BRMIMP is first submitted, these permits shall be submitted to the CPM and USFWS within 10 days of their receipt and the BRMIMP shall be revised or supplemented to reflect the permit conditions within 20 days of their receipt. The project owner shall notify the CPM no less than five working days before implementing any modifications to the approved BRMIMP to obtain CPM approval. Any changes to the approved BRMIMP must also be approved by the CPM in consultation with CDFG, the USFWS, and appropriate agencies to ensure no conflicts exist. Within 30 days after completion of project construction, the project owner shall submit to the CPM, for review and approval, a written report identifying which items of the BRMIMP have been completed, a summary of all modifications to mitigation measures made during the project's site mobilization, ground disturbance, grading, and construction phases, and which mitigation and monitoring items are still outstanding.	12/22/03		x		
BIO-6	OPS	The project owner shall incorporate into the permanent or unexpected permanent closure plan, and the BRMIMP, measures that address the local biological resources. The planned permanent or unexpected permanent closure plan will address the following biological resources related mitigation measures (typical measures are): 1. Removal of transmission conductors when they are no longer used and useful; 2. Removal of all power plant site facilities and related facilities; 3. Measures to restore wildlife habitat to promote the re-establishment of native plant and wildlife species; and 4. Revegetation of the plant site and other disturbed areas utilizing appropriate seed mixture.	At least 12 months prior to commencement of closure activities, the project owner shall address all biological resources related issues associated with facility closure in a Biological Resources Element. The Biological Resources Element shall be incorporated into the Facility Closure Plan and the BRMIMP and include a complete discussion of the local biological resources and proposed facility closure mitigation measures.	12/22/03	x			
BIO-7	PC	The project owner will acquire the Regional Water Quality Control Board Section 401 Clean Water Act certification, and incorporate the biological resource related terms and conditions into the project's BRMIMP.	At least 30 days prior to the start of any site or related facilities mobilization activities, the project owner will submit to the CPM a copy of the final Regional Water Quality Control Board's certification.	12/22/03		x		
BIO-8	PC	The project owner shall submit to the CPM a final copy of the U.S. Army Corps of Engineers Section 404 of the federal Clean Water Act permit. The biological resources related terms and conditions contained in the permit shall be incorporated into the project's BRMIMP.	At least 30 days prior to the start of any site or related facilities mobilization, the project owner shall submit to the CPM a copy of the U.S. Army Corps of Engineers permit.	12/22/03		x		

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BIO-9	PC	The project owner shall modify the project design to incorporate all feasible measures that avoid or minimize impacts to the local biological resources. These modifications may include: 1. Design transmission line poles, access roads, pulling sites, and storage and parking areas to avoid identified sensitive resources. If, in the final design plans, the 500kV or the 115 kV transmission lines are located within four feet of site MW-51, potential impacts to listed fairy shrimp shall be reevaluated by the CPM in coordination with the USFWS. 2. Avoid wetland loss as defined in the Western Riverside County Multi-Species Habitat Conservation Plan or loss of jurisdictional features as defined by the U.S. Army Corps of Engineers; and 3. Design and construct transmission lines and all electrical components to reduce the likelihood of electrocutions of large birds.	All mitigation measures and their implementation methods shall be included in the BRMIMP.	12/22/03		x		
BIO-10	PC	The project owner shall manage its construction site and related facilities, in a manner to avoid or minimize impacts to the local biological resources. Typical and site specific measures shall include: 1. Temporarily fence and provide wildlife escape ramps for construction areas that contain steep walled holes or trenches if outside of an approved, permanent exclusionary fence. The temporary fence shall be hardware cloth or similar materials that are approved for use by USFWS and CDFG; 2. Make certain all food-related trash will be disposed of in closed containers and removed at least once a week. Feeding of wildlife shall be prohibited; 3. Prohibit non-security related firearms or weapons from being brought to the site; 4. Prohibit pets from being brought to the site; 5. Report all inadvertent deaths of sensitive species to the appropriate project representative. Injured animals shall be reported to CDFG and the project owner shall follow instructions that are provided by CDFG; 6. Protect potential vernal pool fairy shrimp habitat identified as site MW-51 from sedimentation or wind (aeolic) deposition originated by project construction; 7. Access to the 0.9-mile transmission line when adjacent to the MW- 51 shall be restricted to the west of the existing and new 500-kV lattice towers; 8. Eliminate any California Exotic Pest Plants of Concern (CalEPPC) List A species from landscaping plans; 9. Use native, drought tolerant species in the restoration of land temporarily disturbed during the installation linear underground facilities; 10. Restore temporarily disturbed sites to their pre-existing physical condition; and 11. In areas that potentially support vernal pool fairy shrimp, the project owner shall perform the following measures: • Biological impacts to potential fairy shrimp habitat shall be minimized to the maximum extent possible by siting facilities away from such sensitive habitats, within disturbed agricultural fields, adjacent to or within existing road or established utility rights-of-way. • Prior to the start of any construction activities in the vicinity of MW-51 (potential vernal pool fairy shrimp habitat), a qualified biologist shall delineate and flag the boundaries of the feature. • K-rail concrete barriers will be installed around the MW-51 feature to protect the feature from construction activities. There shall be a minimum of four feet of clearance between the barrier and the MW-51 feature. The barrier shall be continuous around the MW-51 feature only insofar as it does not interfere with the hydrology of the feature. If it is necessary to allow breaks in the barrier to maintain existing hydrology, then the concrete barrier	All mitigation measures and their implementation methods shall be included in the BRMIMP.	12/22/03		x		
BIO-11	PC	Prior to site or related facilities mobilization, the IEEC shall comply with the provisions of Riverside County Ordinance No. 663, which requires the payment of fees for permanent and temporary loss of historical Stephens' kangaroo rat habitat within the Stephens' kangaroo rat HCP fee assessment area. The applicant shall purchase habitat credits for temporary impacts to 47.63 acres and permanent impacts to 38.60 acres. Fees shall be based on the most current fees assessed by Riverside County. Monies will be paid directly to the Riverside County Habitat Conservation Agency.	At least 30 days prior to site or related facilities mobilization, the project owner shall demonstrate to the CPM evidence of receipt of payment of the Stephens' kangaroo rat habitat fee by the County of Riverside. At least 30 days prior to site mobilization (or other CPM-approved timeframe), the project owner shall submit to the CPM a written certificate or letter from the County of Riverside stating the date and amount of funds received.	06/22/05		x		

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BIO-12	PC	Prior to site or related facilities mobilization, the project owner shall pay an Interim Open Space Mitigation Fee in the amount assessed in accordance with Riverside County Ordinance No. 810 to assist in providing revenue to acquire and preserve open space and habitat (Riverside 2002a). The amount of the fee shall be based on permanent impacts to 38.6 acres using the most current fee rates for industrial projects under this Ordinance. Any area identified as "no use proposed" on the approved exhibit A (i.e., the AFC, Ex. 1) shall not be included in the project area.	At least 30 days prior to site or related facilities mobilization, the project owner shall submit to the CPM documentation that payment has been made to the County of Riverside for the Interim Open Space Mitigation Fee. At least 30 days prior to site or related facilities mobilization (or other CPMapproved timeframe), the project owner shall provide a letter from the County of Riverside stating the date and amount of funds received for open space and habitat mitigation.	12/22/03		x		
BIO-13	CONS	Prior to site or related facilities mobilization, the project owner shall enter into a legally binding agreement with Southern California Edison (SCE), or its successor, regarding construction and maintenance of the transmission line between the Inland Empire Energy Center and the Valley substation. The agreement shall include the measures identified in the BRMIMP and Conditions of Certification BIO-5 and BIO-10. The agreement shall also allow the CPM access to the transmission line corridor throughout construction and operation. The project owner is ultimately responsible for implementation of all mitigation measures associated with the 0.9 mile transmission line.	At least 30 days prior to site or related facilities mobilization along the transmission line corridor, the project owner shall submit to the CPM a copy of the initial agreement between the parties for review and approval. Any proposal to enter into a subsequent agreement must be submitted 30 days in advance of its execution to the CPM for review and approval in consultation with appropriate state, federal, or local authorities. The agreement may be terminated at any time, provided that the terminated agreement is replaced by another agreement which complies with the requirements set forth and is effective immediately upon termination of the prior agreement.	12/22/03		x		
CIVIL-1	PC	The project owner shall submit to the CBO for review and approval the following: 1. Design of the proposed drainage structures and the grading plan; 2. An erosion and sedimentation control plan; 3. Related calculations and specifications, signed and stamped by the responsible civil engineer; and 4. Soils report as required by the 2001 CBC [Appendix Chapter 33, Section 3309.5, Soils Engineering Report; and Section 3309.6, Engineering Geology Report].	At least 15 days (or project owner and CBO approved alternative timeframe) prior to the start of site grading, the project owner shall submit the documents described above to the CBO for design review and approval. In the next Monthly Compliance Report following the CBO's approval, the project owner shall submit a written statement certifying that the documents have been approved by the CBO.	12/22/03		x		
CIVIL-2	CONS	The resident engineer shall, if appropriate, stop all earthwork and construction in the affected areas when the responsible geotechnical engineer or civil engineer, experienced and knowledgeable in the practice of soils engineering, identifies unforeseen adverse soil or geologic conditions. The project owner shall submit modified plans, specifications and calculations to the CBO based on these new conditions. The project owner shall obtain approval from the CBO before resuming earthwork and construction in the affected area [2001 CBC, Section 104.2.4, Stop orders].	The project owner shall notify the CPM within 24 hours, when earthwork and construction is stopped as a result of unforeseen adverse geologic/soil conditions. Within 24 hours of the CBO's approval to resume earthwork and construction in the affected areas, the project owner shall provide the CPM a copy of the CBO's approval.	12/22/03		x		
CIVIL-3	CONS	The project owner shall perform inspections in accordance with the 2001 CBC, Chapter 1, Section 108, Inspections; Chapter 17, Section 1701.6, Continuous and Periodic Special Inspection; and Appendix Chapter 33, Section 3317, Grading Inspection. All plant site-grading operations for which a grading permit is required shall be subject to inspection by the CBO. If, in the course of inspection, it is discovered that the work is not being performed in accordance with the approved plans, the discrepancies shall be reported immediately to the resident engineer, the CBO and the CPM [2001 CBC, Appendix Chapter 33, Section 3317.7, Notification of Noncompliance]. The project owner shall prepare a written report detailing all discrepancies and non-compliance items, and the proposed corrective action, and send copies to the CBO and the CPM.	Within five days of the discovery of any discrepancies, the resident engineer shall transmit to the CBO and the CPM a Non-Conformance Report (NCR) and the proposed corrective action. Within five days of resolution of the NCR, the project owner shall submit the details of the corrective action to the CBO and the CPM. A list of NCRs for the reporting month shall also be included in the following Monthly Compliance Report.	12/22/03		x		
CIVIL-4	CONS	After completion of finished grading and erosion and sedimentation control and drainage work, the project owner shall obtain the CBO's approval of the final grading plans (including final changes) for the erosion and sedimentation control work. The civil engineer shall state that the work within his/her area of responsibility was done in accordance with the final approved plans [2001 CBC, Section 3318, Completion of Work].	Within 30 days of the completion of the erosion and sediment control mitigation and drainage work, the project owner shall submit to the CBO, for review and approval, the final grading plan (including final changes) and the responsible civil engineer's signed statement that the installation of the facilities and all erosion control measures were completed in accordance with the final approved combined grading plans, and that the facilities are adequate for their intended purposes. The project owner shall submit a copy of the CBO's approval to the CPM in the next Monthly Compliance Report.	12/22/03		x		

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COM-1	Ongoing	The project owner shall grant Energy Commission staff and delegate agencies or consultants unrestricted access to the power plant site.		12/22/03	x			
COM-2	Ongoing	The project owner shall maintain project files onsite. Energy Commission staff and delegate agencies shall be given unrestricted access to the files.		12/22/03	x			
COM-3	Ongoing	The project owner is responsible for the delivery and content of all verification submittals to the CPM, whether the condition was satisfied by work performed by the project owner or his agent.		12/22/03	x			
COM-4	PC	Construction shall not commence until all of the following activities/ submittals have been completed: property owners living within one mile of the project have been notified of a telephone number to contact for questions, complaints or concerns; a pre-construction matrix has been submitted identifying only those conditions that must be fulfilled before the start of construction; all pre-construction conditions have been complied with; and the CPM has issued a letter to the project owner authorizing construction.		12/22/03		x		
COM-5	CONS	The project owner shall submit a compliance matrix (in a spreadsheet format) with each monthly and annual compliance report which includes the status of all compliance conditions of certification.		12/22/03	x			
COM-6	CONS	During construction, the project owner shall submit Monthly Compliance Reports (MCRs) which include specific information. The first MCR is due the month following the Commission business meeting date on which the project was approved and shall include an initial list of dates for each of the events identified on the Key Events List.		12/22/03		x		
COM-7	OPS	After construction ends and throughout the life of the project, the project owner shall submit Annual Compliance Reports instead of Monthly Compliance Reports.		12/22/03	x			
COM-8	PC	Thirty days prior to commencing construction, the project owner shall submit a Security Plan for the construction phase. Sixty days prior to initial receipt of hazardous material on site, the project owner shall submit an Security Plan & Vulnerability Assessment for the operational phase.		12/22/03		x		
COM-9	Ongoing	Any information the project owner deems confidential shall be submitted to the Dockets Unit with an application for confidentiality.		12/22/03	x			
COM-10	PC	The project owner shall pay a filing fee of $850 at the time of project certification.		12/22/03		x		
COM-11	PC	Within 10 days of receipt, the project owner shall report to the CPM, all notices, complaints, and citations.		12/22/03	x			
COM-12	OPS	The project owner shall submit a closure plan to the CPM at least twelve months prior to commencement of a planned closure.		12/22/03	x			
COM-13	COMM	To ensure that public health and safety and the environment are protected in the event of an unplanned temporary closure, the project owner shall submit an on-site contingency plan no less than 60 days prior to commencement of commercial operation.		12/22/03		x		
COM-14	COMM	To ensure that public health and safety and the environment are protected in the event of an unplanned permanent closure, the project owner shall submit an on-site contingency plan no less than 60 days prior to commencement of commercial operation.		12/22/03		x		
COM-15	PC	The project owner shall establish specific performance milestones for pre-construction and construction phases of the project.		12/22/03		x		

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CUL-1	PC	Prior to the start of ground disturbance, the project owner shall obtain the services of a Cultural Resources Specialist (CRS), and one or more alternates, if alternates are needed, to manage all monitoring, mitigation, and curation activities. The CRS may elect to obtain the services of Cultural Resource Monitors (CRMs) and other technical specialists, if needed, to assist in monitoring, mitigation and curation activities. The project owner shall ensure that the CRS evaluates any cultural resources that are newly discovered or that may be affected in an unanticipated manner for eligibility to the California Register of Historic Resources (CRHR). CULTURAL RESOURCES SPECIALIST The resume for the CRS and alternate(s) shall include information demonstrating that the minimum qualifications specified in the U.S. Secretary of Interior Guidelines, as published in the Code of Federal Regulations, 36 CFR Part 61 are met. In addition, the CRS shall have the following qualifications: 1. a technical specialty appropriate to the needs of the project and a background in anthropology, archaeology, history, architectural history, or a related field; and 2. at least three years of archaeological or historic, as appropriate, resource mitigation and field experience in California. The resume of the CRS shall include the names and telephone numbers of contacts familiar with the work of the CRS on referenced projects, and demonstrate that the CRS has the appropriate education and experience to accomplish the cultural resource tasks that must be addressed during ground disturbance, grading, construction, and operation. In lieu of the above requirements, the resume shall demonstrate to the satisfaction of the CPM that the proposed CRS or alternate has the appropriate training and background to effectively implement the Conditions of Certification. CULTURAL RESOURCES MONITOR CRMs shall have the following qualifications: 1. a BS or BA degree in anthropology, archaeology, historic archaeology, or a related field and one year experience monitoring in California; or 2. an AS or AA degree in anthropology, archaeology, historic archaeology, or a related field and four years experience monitoring in California; or 3. enrollment in upper division classes pursuing a degree in the fields of anthropology, archaeology, historic archaeology, or a related field and two years of monitoring experience in California.	The project owner shall submit the resume for the CRS, and alternate(s) if desired, at least 45 days prior to the start of ground disturbance to the CPM for review and approval. At least 10 days prior to a termination or release of the CRS, the project owner shall submit the resume of the proposed new CRS to the CPM for review and approval. At least 20 days prior to ground disturbance, the CRS shall submit written notification to the CPM identifying anticipated CRMs for the project stating they meet the minimum qualifications required by this condition. If additional CRMs are needed later, the CRS shall submit written notice one week prior to any new CRMs beginning work. At least 10 days prior to the start of ground disturbance, the project owner shall confirm in writing to the CPM that the approved CRS will be available for on-site work and is prepared to implement the cultural resources Conditions of Certification.	12/22/03		x		
CUL-2	PC	Prior to the start of ground disturbance, the project owner shall provide the CRS and the CPM with maps and drawings showing the footprint of the power plant and all linear facilities. Maps shall include the appropriate USGS quadrangles and a map at an appropriate scale (e.g., 1:2000 or 1" = 200') for plotting individual artifacts. If the CRS requests enlargements or strip maps for linear facility routes, the project owner shall provide copies to the CRS and CPM. If the footprint of the power plant or linear facilities changes, the project owner shall provide maps and drawings reflecting these changes to the CRS and the CPM for approval. Maps shall identify all areas of the project where ground disturbance is anticipated. If construction of the project will proceed in phases, maps and drawings, not previously provided, shall be submitted prior to the start of each phase. Written notification identifying the schedule of each project phase shall be provided to the CRS and CPM. At a minimum, the CRS shall consult weekly with the project construction manager to confirm area(s) to be worked during the next week, until ground disturbance is completed. The project owner shall notify the CRS and CPM of any changes to the scheduling of the construction phases.	The project owner shall submit the subject maps and drawings at least 30 days prior to the start of ground disturbance. If there are changes to any project related footprint, revised maps and drawings shall be provided at least 10 days prior to start of ground disturbance for those changes. If project construction is phased, if not previously provided, the project owner shall submit the subject maps and drawings 15 days prior to each phase. A current schedule of anticipated project activity shall be provided to the CRS on a weekly basis during ground disturbance and also provided in each Monthly Compliance Report (MCR). The project owner shall provide written notice of any changes to scheduling of construction phases within five days of identifying the changes.	12/22/03		x		

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CUL-3	CONS	Cultural resource monitoring shall be conducted during the initial groundbreaking at the plant site and the on project's linear facilities. The potential for encountering buried deposits shall be assessed by the CRS based on the initial groundbreaking observations. The initial assessment shall prescribe the type (intermittent to full time), location, and duration for monitoring of ground disturbance within the plant site and on the project's linear facilities and show that the CPM has concurred with that determination. The cultural resource monitoring shall continue until the CRS determines that no cultural resources will be impacted by continued construction. Monitors shall keep a daily log of any monitoring or cultural resource activities, these logs shall be submitted weekly. The CRS shall prepare a monthly summary report on the progress or status of cultural resourcesrelated activities. The CRS may informally discuss cultural resource monitoring and mitigation activities with Energy Commission technical staff. The CRS and the project owner shall notify the CPM by telephone or email of any incidents of non-compliance with the Conditions of Certification and/or applicable LORS within 24 hours of becoming aware of the situation. The CRS shall also recommend corrective action to resolve the problem or achieve compliance with the Conditions of Certification. Cultural resources monitoring activities are the responsibility of the CRS. Any interference with monitoring activities, removal of a monitor from duties assigned by the CRS or direction to a monitor to relocate monitoring activities by anyone other than the CRS shall be considered non-compliance with these conditions of certification. A Native American monitor shall be obtained, at a minimum on an on-call basis, to monitor ground disturbance in areas where Native American artifacts are discovered. Informational lists prepared by the Native American Heritage Commission of concerned Native Americans shall be obtained. Preference in selecting a monitor shall be given to Native Americans with traditional ties to the area that will be monitored.	Within 5 days after the initial groundbreaking, the CRS or alternate CRS will provide a letter (electronic or paper) to the CPM and the project owner of the assessment of the initial groundbreaking observations, including the type (intermittent to full time) and duration of cultural resources monitoring for review and approval by the CPM. Monitoring shall not be completed until the CRS has determined that continued construction will not result in an impact to cultural resources and has provided a letter stating so to the CPM and the project owner. During the ground disturbance phases of the project, all daily logs will be submitted on a weekly basis to the CPM either through email, fax, or hard copy. During the ground disturbance phases of the project, the project owner shall include in the MCR to the CPM copies of the monthly summary reports prepared by the CRS regarding project-related cultural resources monitoring. Within 24 hours of recognition of a non-compliance issue with the Conditions of Certification and/or applicable LORS, the CRS and the project owner shall notify the CPM by telephone of the problem and of steps being taken to resolve the problem. The telephone call shall be followed by an e-mail or fax detailing the non-compliance issue and the measures necessary to achieve resolution of the issue. Daily logs shall include forms detailing any instances of non-compliance. In the event of any non-compliance issue, a report written no sooner than two weeks and no later than six weeks after a non-compliance incident that describes the issue, resolution of the issue, and the effectiveness of the resolution measures shall be provided in the MCR following completion of the report. When Native American artifacts are found, the project owner shall send notification to the CPM identifying the person(s) retained, at a minimum, on an on-call basis to conduct Native American monitoring. If efforts to obtain the services of a qualified Native American monitor are unsuccessful, the project owner shall immediately inform the CPM who will initiate a resolution process.	12/22/03		x		
CUL-4	CONS	The project owner shall submit the Cultural Resources Report (CRR) to the CPM for approval. The CRR shall be written by the CRS and shall be provided in the Archaeological Resources Management Report (ARMR) format. The CRR shall report on all field activities including dates, times and locations, findings, samplings, and analysis. All survey reports, DPR 523 forms, and additional research reports not previously submitted to the California Historic Resource Information System (CHRIS) shall be included as an appendix to the CRR.	The project owner shall submit the CRR within 90 days after completion of ground disturbance (including landscaping). Within 10 days after CPM approval, the project owner shall provide documentation to the CPM that copies of the CRR have been provided to the State Historic Preservation Officer (SHPO), the CHRIS, and the curating institution (if archaeological materials were collected).	12/22/03		x		

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CUL-5	CONS	Prior to and for the duration of ground disturbance, the project owner shall provide Worker Environmental Awareness Program (WEAP) training to all new workers within their first week of employment. The training may be presented in the form of a video. The training shall include: 1. a discussion of applicable laws and penalties under the law; 2. samples or visuals of artifacts that might be found in the project vicinity; 3. information that the CRS, alternate CRS, or CRM has the authority to halt construction in the event of a discovery or unanticipated impact to a cultural resource; 4. instruction that employees are to halt work on their own in the vicinity of a potential cultural resources find, and shall contact their supervisor and the CRS or CRM; redirection of work would be determined by the construction supervisor and the CRS; 5. an informational brochure that identifies reporting procedures in the event of a discovery; 6. an acknowledgement form signed by each worker indicating that they have received the training; and 7. a sticker that shall be placed on each employee's hard hat indicating that that employee has completed environmental training.	The project owner shall provide in the Monthly Compliance Report the WEAP Certification of Completion form of workers who have completed the training in the prior month, as well as a running total of all workers who have completed training to date.	12/22/03		x		
CUL-6	PC	The project owner shall grant authority to halt construction to the CRS, alternate CRS, and the CRMs in the event previously unknown cultural resource sites or materials are encountered, or if known resources may be impacted in a previously unanticipated manner (discovery). Redirection of ground disturbance shall be accomplished under the direction of the construction supervisor in consultation with the CRS. In the event of a discovery, the halting or redirection of construction shall remain in effect until the CRS has determined the discovery is categorically treated as not significant as defined in the research design below, or all of the following have occurred: 1. the CRS has notified the project owner, and the CPM has been notified within 24 hours or by Monday morning if the cultural resources discovery occurs between 8:00 AM on Friday and 8:00 AM on Sunday morning, including a description of the discovery (or changes in character or attributes), the action taken (i.e. work stoppage or redirection), a recommendation of eligibility and recommendations for mitigation of any cultural resources discoveries whether or not a determination of significance has been made ; 2. the CRS, the project owner, and the CPM have conferred and determined what, if any, data recovery or other mitigation is needed; and 3. any necessary data recovery and mitigation has been completed. A research design shall be prepared to identify the information values that may be contained in a typical cultural resource deposit. The research design shall provide guidance for determining the significance of cultural resource deposits and provide a list of those resources that shall be categorically treated as not significant. The design shall provide justification for decisions on significance and methodology for determining the age of deposits.	At least 30 days prior to the start of ground disturbance, the project owner shall provide the CPM with a letter confirming that the CRS, alternate CRS, and CRMs have the authority to halt construction activities in the vicinity of a cultural resource find, and that the CRS or project owner shall notify the CPM immediately (no later than the following morning of the incident or Monday morning in the case of a weekend) of any halt of construction activities, including the circumstances and proposed mitigation measures. The project owner shall provide the CRS with a copy of the letter granting the authority to halt construction. At least 30 days prior to the start of ground disturbance, the project owner shall provide the CPM a research design developed by the CRS for review and approval.	12/22/03		x		
CUL-7	CONS	If any cultural materials are collected as identified in the research design, following the filing of the CPM-approved CRR with the appropriate entities the project owner shall ensure that all cultural resource materials, maps, and data collected during data recovery and mitigation for the project are delivered to a public repository that meets the U.S. Secretary of Interior requirements for the curation of cultural resources. The project owner shall pay any fees for curation required by the repository.	The project owner shall ensure that all recovered cultural resource materials are delivered for curation within 30 days after providing the CPM-approved CRR. For the life of the project, the project owner shall maintain in its compliance files copies of signed contracts or agreements with the public repository to which the project owner has delivered for curation all cultural resource materials collected during data recovery and mitigation for the project.	12/22/03		x		

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ELEC-1	CONS	Prior to the start of any increment of electrical construction for electrical equipment and systems 480 volts and higher listed below, with the exception of underground duct work and any physical layout drawings and drawings not related to code compliance and life safety, the project owner shall submit, for CBO design review and approval, the proposed final design, specifications, and calculations [CBC 2001, Section 106.3.2, Submittal documents]. Upon approval, the above listed plans, together with design changes and design change notices, shall remain on the site or at another accessible location for the operating life of the project. The project owner shall request that the CBO inspect the installation to ensure compliance with the requirements of applicable LORS [2001 CBC, Section 108.4, Approval Required, and Section 108.3, Inspection Requests]. All transmission facilities (lines, switchyards, switching stations, and substations) are covered in Conditions of Certification in the Transmission System Engineering section of this document. A. Final plant design plans to include: 1. one-line diagrams for the 13.8 kV, 4.16 kV and 480 V systems; and 2. system grounding drawings. B. Final plant calculations to establish: 1. short-circuit ratings of plant equipment; 2. ampacity of feeder cables; 3. voltage drop in feeder cables; 4. system grounding requirements; 5. coordination study calculations for fuses, circuit breakers, and protective relay settings for the 13.8 kV, 4.16 kV, and 480 V systems; 6. system grounding requirements; and 7. lighting energy calculations. C. The following activities shall be reported to the CPM in the Monthly Compliance Report: 1. Receipt or delay of major electrical equipment; 2. Testing or energization of major electrical equipment; and 3. A signed statement by the registered electrical engineer certifying that the proposed final design plans and specifications conform to requirements set forth in the Energy Commission Decision.	At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of each increment of electrical construction, the project owner shall submit to the CBO for design review and approval the above listed documents. The project owner shall include in this submittal a copy of the signed and stamped statement from the responsible electrical engineer attesting compliance with the applicable LORS, and shall send the CPM a copy of the transmittal letter in the next Monthly Compliance Report.	12/22/03		x		
GEN-1	CONS	The project owner shall design, construct, and inspect the project in accordance with the 2001 California Building Code (CBC) and all other applicable engineering LORS in effect at the time initial design plans are submitted to the CBO for review and approval. (The CBC in effect is that edition that has been adopted by the California Building Standards Commission and published at least 180 days previously.) All transmission facilities (lines, switchyards, switching stations and substations) are covered in Conditions of Certification in the Transmission System Engineering section of this document. In the event that the initial engineering designs are submitted to the CBO when a successor to the 2001 CBC is in effect, the 2001 CBC provisions identified herein shall be replaced with the applicable successor provisions. Where, in any specific case, different sections of the code specify different materials, methods of construction or other requirements, the most restrictive shall govern. Where there is a conflict between a general requirement and a specific requirement, the specific requirement shall govern.	Within 30 days after receipt of the Certificate of Occupancy, the project owner shall submit to the CPM a statement of verification, signed by the responsible design engineer, attesting that all designs, construction, installation and inspection requirements of the applicable LORS and the Energy Commission's Decision have been met in the area of facility design. The project owner shall provide the CPM a copy of the Certificate of Occupancy within 30 days of receipt from the CBO [2001 CBC, Section 109 – Certificate of Occupancy].	12/22/03		x		

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GEN-2	PC	Prior to submittal of the initial engineering designs for CBO review, the project owner shall furnish to the CPM and to the CBO a schedule of facility design submittals, a Master Drawing List, and a Master Specifications List. The schedule shall contain a list of proposed submittal packages of designs, calculations, and specifications for major structures and equipment. To facilitate audits by Energy Commission staff, the project owner shall provide specific packages to the CPM when requested.	At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of rough grading, the project owner shall submit to the CBO and to the CPM the schedule, the Master Drawing List, and the Master Specifications List of documents to be submitted to the CBO for review and approval. These documents shall be the pertinent design documents for the major structures and equipment listed in Table 1 below. Major structures and equipment shall be added to or deleted from the Table only with CPM approval. The project owner shall provide schedule updates in the Monthly Compliance Report.	12/22/03		x		
GEN-3	CONS	The project owner shall make payments to the CBO for design review, plan check and construction inspection based upon a reasonable fee schedule to be negotiated between the project owner and the CBO. These fees may be consistent with the fees listed in the 2001 CBC [Chapter 1, Section 107 and Table 1-A, Building Permit Fees; Appendix Chapter 33, Section 3310 and Table A-33-A, Grading Plan Review Fees; and Table A-33-B, Grading Permit Fees], adjusted for inflation and other appropriate adjustments; may be based on hourly rates; or may be as otherwise agreed by the project owner and the CBO.	The project owner shall make the required payments to the CBO in accordance with the agreement between the project owner and the CBO. The project owner shall send a copy of the CBO's receipt of payment to the CPM in the next Monthly Compliance Report indicating that the applicable fees have been paid.	12/22/03		x		
GEN-4	PC	Prior to the start of rough grading, the project owner shall assign a California registered architect, structural engineer, or civil engineer as a resident engineer (RE) to be in general responsible charge of the project [Building Standards Administrative Code (Cal Code of Regs., tit. 24, § 4- 209, Designation of Responsibilities)]. All transmission facilities (lines, switchyards, switching stations and substations) are covered in conditions of certification in the Transmission System Engineering section of this document. The RE may delegate responsibility for portions of the project to other registered engineers. Registered mechanical and electrical engineers may be delegated responsibility for mechanical and electrical portions of the project, respectively. A project may be divided into parts, provided each part is clearly defined as a distinct unit. Separate assignment of general responsible charge may be made for each designated part. The RE shall: 1. Monitor construction progress of work requiring CBO design review and inspection to ensure compliance with LORS; 2. Ensure that construction of all the facilities subject to CBO design review and inspection conforms in every material respect to the applicable LORS, these Conditions of Certification, approved plans, and specifications; 3. Prepare documents to initiate changes in the approved drawings and specifications when directed by the project owner or as required by conditions on the project; 4. Be responsible for providing the project inspectors and testing agency(ies) with complete and up-to-date set(s) of stamped drawings, plans, specifications and any other required documents; 5. Be responsible for the timely submittal of construction progress reports to the CBO from the project inspectors, the contractor, and other engineers who have been delegated responsibility for portions of the project; and 6. Be responsible for notifying the CBO of corrective action or the disposition of items noted on laboratory reports or other tests as not conforming to the approved plans and specifications. The RE shall have the authority to halt construction, and to require changes or remedial work, if the work does not conform to applicable requirements. If the RE or the delegated engineers are reassigned or replaced, the project owner shall submit the name, qualifications and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer.	At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, the resume and registration number of the RE and any other delegated engineers assigned to the project. The project owner shall notify the CPM of the CBO's approvals of the RE and other delegated engineer(s) within five days of the approval. If the RE or the delegated engineer(s) are subsequently reassigned or replaced, the project owner has five days in which to submit the resume and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.	12/22/03		x		

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GEN-5	CONS	Prior to the start of construction, the project owner shall assign at least one of each of the following California registered engineers to the project: a) a civil engineer; b) a geotechnical engineer or a civil engineer experienced and knowledgeable in the practice of soils engineering; c) a design engineer, who is either a structural engineer or a civil engineer fully competent and proficient in the design of power plant structures and equipment supports; d) a mechanical engineer; and e) an electrical engineer. [California Business and Professions Code section 6704 et seq., and sections 6730 and 6736 requires state registration to practice as a civil engineer or structural engineer in California.] All transmission facilities (lines, switchyards, switching stations and substations) are covered in Conditions of Certification in the Transmission System Engineering section of this document. The tasks performed by the civil, mechanical, electrical or design engineers may be divided between two or more engineers, as long as each engineer is responsible for a particular segment of the project (e.g., proposed earthwork, civil structures, power plant structures, equipment support). No segment of the project shall have more than one responsible engineer. The transmission line may be the responsibility of a separate California registered electrical engineer. The project owner shall submit to the CBO, for review and approval, the names, qualifications, and registration numbers of all responsible engineers assigned to the project [2001 CBC, Section 104.2, Powers and Duties of Building Official]. If any one of the designated responsible engineers is subsequently reassigned or replaced, the project owner shall submit the name, qualifications, and registration number of the newly assigned responsible engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer. A: The civil engineer shall: 1. Design, or be responsible for design, stamp, and sign all plans, calculations, and specifications for proposed site work, civil works and related facilities requiring design review and inspection by the CBO. At a minimum, these include grading, site preparation, excavation, compaction, construction of secondary containment, foundations, erosion and sedimentation control structures, drainage facilities, underground utilities, culverts, site access roads, and sanitary sewer systems; and 2. Provide consultation to the RE during the construction phase of the project and recommend changes in the design of the civil works facilities and changes in the construction procedures.	At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of rough grading, the project owner shall submit to the CBO for review and approval, resumes and registration numbers of all the responsible engineers assigned to the project. The project owner shall notify the CPM of the CBO's approvals of the engineers within five days of the approval. If the designated responsible engineer is subsequently reassigned or replaced, the project owner has five days in which to submit the resume and registration number of the newly assigned engineer to the CBO for review and approval. The project owner shall notify the CPM of the CBO's approval of the new engineer within five days of the approval.	12/22/03		x		

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GEN-6	CONS	Prior to the start of an activity requiring special inspection, the project owner shall assign to the project qualified and certified special inspector(s) who shall be responsible for the special inspections required by the 2001 CBC, Chapter 17 [Section 1701, Special Inspections; Section 1701.5, Type of Work (requiring special inspection)]; and Section 106.3.5, Inspection and observation program. All transmission facilities (lines, switchyards, switching stations and substations) are covered in Conditions of Certification in the Transmission System Engineering section of this document. The special inspector shall: 1. Be a qualified person who shall demonstrate competence, to the satisfaction of the CBO, for inspection of the particular type of construction requiring special or continuous inspection; 2. Observe the work assigned for conformance with the approved design drawings and specifications; 3. Furnish inspection reports to the CBO and RE. All discrepancies shall be brought to the immediate attention of the RE for correction then, if uncorrected, to the CBO and the CPM for corrective action [2001 CBC, Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector]; and 4. Submit a final signed report to the RE, CBO, and CPM stating whether the work requiring special inspection was, to the best of the inspector's knowledge, in conformance with the approved plans and specifications as well as the applicable provisions of the applicable edition of the CBC. A certified weld inspector, certified by the American Welding Society (AWS) and/or American Society of Mechanical Engineers (ASME) as applicable, shall inspect welding performed on-site requiring special inspection (including structural, piping, tanks and pressure vessels).	At least 15 days (or project owner and CBO approved alternative timeframe) prior to the start of an activity requiring special inspection, the project owner shall submit to the CBO for review and approval, with a copy to the CPM, the name(s) and qualifications of the certified weld inspector(s), or other certified special inspector(s) assigned to the project to perform one or more of the duties set forth above. The project owner shall also submit to the CPM a copy of the CBO's approval of the qualifications of all special inspectors in the next Monthly Compliance Report. If the special inspector is subsequently reassigned or replaced, the project owner has five days in which to submit the name and qualifications of the newly assigned special inspector to the CBO for approval. The project owner shall notify the CPM of the CBO's approval of the newly assigned inspector within five days of the approval.	12/22/03		x		
GEN-7	CONS	If any discrepancy in design and/or construction is discovered in any engineering work that has undergone CBO design review and approval, the project owner shall document the discrepancy and recommend the corrective action required [2001 CBC, Chapter 1, Section 108.4, Approval Required; Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector; Appendix Chapter 33, Section 3317.7, Notification of Noncompliance]. The discrepancy documentation shall be submitted to the CBO for review and approval. The discrepancy documentation shall reference this Condition of Certification and, if appropriate, the applicable sections of the CBC and/or other LORS. The project owner shall transmit a copy of the CBO's approval of any corrective action taken to resolve a discrepancy to the CPM in the next Monthly Compliance Report. If any corrective action is disapproved, the project owner shall advise the CPM, within five days, of the reason for disapproval andthe revised corrective action to obtain CBO's approval.	The project owner shall transmit a copy of the CBO's approval of any corrective action taken to resolve a discrepancy to the CPM in the next Monthly Compliance Report. If any corrective action is disapproved, the project owner shall advise the CPM, within five days, of the reason for disapproval and the revised corrective action to obtain CBO's approval.	12/22/03		x		

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GEN-8	CONS	The project owner shall obtain the CBO's final approval of all completed work that has undergone CBO design review and approval. The project owner shall request the CBO to inspect the completed structure and review the submitted documents. When the work and the "as-built" and "as graded" plans conform to the approved final plans, the project owner shall notify the CPM regarding the CBO's final approval. The marked up "as-built" drawings for the construction of structural and architectural work shall be submitted to the CBO. Changes approved by the CBO shall be identified on the "as-built" drawings [2001 CBC, Section 108, Inspections]. The project owner shall retain one set of approved engineering plans, specifications, and calculations at the project site or at another accessible location during the operating life of the project [2001 CBC, Section 106.4.2, Retention of Plans].	Within 15 days of the completion of any work, the project owner shall submit to the CBO, with a copy to the CPM in the next Monthly Compliance Report, (a) a written notice that the completed work is ready for final inspection, and (b) a signed statement that the work conforms to the final approved plans. After storing final approved engineering plans, specifications and calculations as described above, the project owner shall submit to the CPM a letter stating that the above documents have been stored and indicate the storage location of such documents.	12/22/03		x		
HAZ-1	OPS	The project owner shall not use any hazardous materials not listed in Appendix C, below, or in greater quantities than those identified by chemical name in Appendix C, below, unless approved in advance by Riverside County and the Compliance Project Manager (CPM).	The project owner shall provide to the CPM, in the Annual Compliance Report, a list of hazardous materials present at the facility in reportable quantities.	12/22/03	x			
HAZ-2	CONS	The project owner shall provide a Business Plan to the Certified Unified Program Authority (CUPA) (Riverside County Environmental Health Department) for review and to the CPM for review. The project owner shall also provide a Risk Management Plan (RMP) to the CUPA and the CPM for review at the time the RMP is first submitted to the U.S. Environmental Protection Agency (EPA). After receiving comments from the CUPA and the CPM, the project owner shall reflect all recommendations in the final documents. Copies of the final Business Plan and RMP shall be provided to the CUPA and EPA for information and to the CPM for approval.	At least 45 days prior to receiving any hazardous material on the site, the project owner shall provide a copy of the final Business Plan to the CPM for approval. At least 60 days prior to delivery of aqueous ammonia to the site, the project owner shall provide the final RMP to the CUPA for information and to the CPM for approval.	12/22/03	x			
HAZ-3	CONS	The project owner shall develop and implement a Safety Management Plan for delivery of aqueous ammonia. The plan shall include procedures, protective equipment requirements, training, and a checklist. It shall also include a section describing all measures to be implemented to prevent mixing of aqueous ammonia with incompatible hazardous materials.	At least 30 days prior to the initial delivery of aqueous ammonia to the facility, the project owner shall provide a safety management plan as described above to the CPM for review and approval.	12/22/03		x		
HAZ-4	CONS	The aqueous ammonia storage facility shall be designed to either the ASME Boiler & Pressure Vessel Code and ANSI K61.1 or to API 620. In either case, a secondary containment basin capable of holding the largest tank volume, plus the volume associated with 24 hours of rain assuming the 25-year storm, shall be provided to contain any releases from the storage tanks.	At least 30 days prior to the initial delivery of aqueous ammonia to the facility, the project owner shall submit final design drawings and specifications for the ammonia storage tank and secondary containment basin to the CPM for review and approval.	12/22/03		x		
HAZ-5	CONS	The project owner shall ensure that no flammable material is stored within 50 feet of the sulfuric acid tank.	At least 30 days prior to initial receipt of sulfuric acid on-site, the project owner shall provide copies of the facility design drawings showing the location of the sulfuric acid storage tank and the location of any tanks, drums, or piping containing any flammable materials.	12/22/03		x		
HAZ-6	CONS	The project owner shall ensure that the gas pipeline undergoes a complete design review and detailed inspection 30 days after initial startup and every 5 years thereafter. Those portions of the natural gas pipeline that are owned by a regulated public utility which is subject to a substantively similar requirement shall not be subject to this condition.	At least 30 days prior to the initial flow of gas in the pipeline, the project owner shall undertake a full and comprehensive pipeline design review. The project owner shall provide an outline of the pipeline design plan to the CPM for review and approval. The full and complete plan shall be amended, as appropriate, and submitted to the CPM for review and approval not later than one year before the plan is implemented by the project owner.	12/22/03		x		
HAZ-7	CONS	After any significant seismic event in the area where surface rupture occurs within one mile of the pipeline, the gas pipeline shall be inspected by the project owner. Those portions of the natural gas pipeline that are owned by a regulated public utility which is subject to a substantively similar requirement shall not be subject to this condition.	At least 30 days prior to the initial flow of gas in the pipeline, the project owner shall provide a detailed plan to the CPM for review and approval so that the CPM is assured that a full and comprehensive pipeline inspection will occur in the event of an earthquake. This plan shall be amended, as appropriate, and submitted to the CPM for review and approval at least every five years.	12/22/03		x		

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HAZ-8	CONS	The project owner shall direct all vendors delivering aqueous ammonia to the site to use only tanker truck transport vehicles which meet or exceed the specifications of DOT Code MC-307.	At least 30 days prior to the first receipt of aqueous ammonia on site, the project owner shall submit copies of the notification letter to supply vendors indicating the transport vehicle specifications to the CPM for review and approval.	12/22/03		x		
HAZ-9	CONS	The project owner shall ensure that the hydrogen gas storage cylinders are stored in an area out of the plane of the turbines and per the clearance requirements of NFPA 50A.	At least 30 days prior to the first receipt of hydrogen gas on-site, the project owner shall provide copies of the facility design drawings showing the location of the hydrogen gas cylinders and the location of any tanks, drums, or piping containing any combustible or flammable material.	12/22/03		x		
HAZ-10	CONS	The project owner shall direct and require all vendors delivering any hazardous material to the site to use only the route approved by the CPM (I-215 to Ethanac Road to Antelope Road and then into the facility). The project owner shall obtain approval of the CPM if an alternate route is desired.	At least 30 days prior to the first receipt of any hazardous materials on site, the project owner shall submit copies of the required transportation route to the CPM for review and approval.	12/22/03		x		
HAZ-11	CONS	The project owner shall direct all vendors carrying any liquid hazardous materials greater than 500 gallons not to deliver during the time in the mornings and afternoons when children are going to and from school. The project owner shall coordinate with any present or future schools near the facility regarding the times when students may be traveling in the transportation route area.	At least 30 days prior to the first receipt of any hazardous materials on site, the project owner shall submit documentation to the CPM identifying the hours that delivery of hazardous materials may and may not take place.	12/22/03		x		
HAZ-12	CONS	The project owner shall ensure that the construction, operation, and maintenance of the natural gas pipeline is done in compliance with Public Utilities Commission General Order 112-E and 58-A standards, and Federal Department of Transportation (DOT) regulations, Title 49, Code of Federal Regulations (CFR), Parts 190, 191, and 192. Those portions of the natural gas pipeline that are owned by a regulated public utility which is subject to a substantively similar requirement shall not be subject to this condition.	At least 30 days prior to the construction of the gas pipeline, the project owner shall provide proof that the above regulations will be complied with to the CPM	12/22/03		x		
HAZ-13	CONS	The project owner shall include the following safety measures for the natural gas compressor enclosure: 1. inside natural gas sensors 2. inside fire (flame) detectors 3. remotely operated gas compressor shut-off valves actuated by the plant operator from the control room 4. outside manual shut-off valves located at least 50 feet from the gas compressor building 5. CO2 fire suppression system for the compressor enclosures 6. unobstructed access to the compressor building by off-site fire department equipment and personnel from two directions 7. a maintenance schedule for the gas compressors	At least thirty (30) days prior to the introduction of natural gas to the pipeline, the project owner shall provide the CPM with a written description of the safety measures applied to the gas compressor enclosure.	06/22/05		x		
LAND-1	PC	Prior to the start of construction, the project owner shall obtain the necessary approval(s) from the County and complete any lot merger or lot line adjustments necessary to ensure that the proposed project, including associated facilities, improvements and buffer areas which would allow adjacent parcels to be developed to their full extent as presently zoned, will be located on a single legal lot.	Within 30 days prior to the start of construction, the project owner shall provide the CPM with proof of completion of the above adjustments or satisfactory evidence that no such adjustments are necessary.	12/22/03		x		

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MECH-1	CONS	The project owner shall submit, for CBO design review and approval, the proposed final design, specifications and calculations for each plant major piping and plumbing system listed in Table 1, Condition of Certification GEN 2, above. Physical layout drawings and drawings not related to code compliance and life safety need not be submitted. The submittal shall also include the applicable QA/QC procedures. Upon completion of construction of any such major piping or plumbing system, the project owner shall request the CBO's inspection approval of said construction [2001 CBC, Section 106.3.2, Submittal Documents; Section 108.3, Inspection Requests; Section 108.4, Approval Required; 2001 California Plumbing Code, Section 103.5.4, Inspection Request; Section 301.1.1, Approval]. The responsible mechanical engineer shall stamp and sign all plans, drawings, and calculations for the major piping and plumbing systems subject to the CBO design review and approval, and submit a signed statement to the CBO when the said proposed piping and plumbing systems have been designed, fabricated, and installed in accordance with all of the applicable laws, ordinances, regulations, and industry standards [Section 106.3.4, Architect or Engineer of Record], which may include, but not be limited to: American National Standards Institute (ANSI) B31.1 (Power Piping Code); ANSI B31.2 (Fuel Gas Piping Code); ANSI B31.3 (Chemical Plant and Petroleum Refinery Piping Code); ANSI B31.8 (Gas Transmission and Distribution Piping Code); Title 24, California Code of Regulations, Part 5 (California Plumbing Code); Title 24, California Code of Regulations, Part 6 (California Energy Code, for building energy conservation systems and temperature control and ventilation systems); Title 24, California Code of Regulations, Part 2 (California Building Code); and Specific City/County code. The CBO may deputize inspectors to carry out the functions of the code enforcement agency [2001 CBC, Section 104.2.2, Deputies].	At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of any increment of major piping or plumbing construction listed in Table 1, Condition of Certification GEN-2 above, the project owner shall submit to the CBO for design review and approval the final plans, specifications, and calculations, including a copy of the signed and stamped statement from the responsible mechanical engineer certifying compliance with the applicable LORS, and shall send the CPM a copy of the transmittal letter in the next Monthly Compliance Report. The project owner shall transmit to the CPM, in the Monthly Compliance Report following completion of any inspection, a copy of the transmittal letter conveying the CBO's inspection approvals.	12/22/03		x		
MECH-2	CONS	For all pressure vessels installed in the plant, the project owner shall submit to the CBO and California Occupational Safety and Health Administration (Cal-OSHA), prior to operation, the code certification papers and other documents required by the applicable LORS. Upon completion of the installation of any pressure vessel, the project owner shall request the appropriate CBO and/or Cal-OSHA inspection of said installation [2001 CBC, Section 108.3, Inspection Requests]. The project owner shall: 1. Ensure that all boilers and fired and unfired pressure vessels are designed, fabricated and installed in accordance with the appropriate section of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code or other applicable code. Vendor certification, with identification of applicable code, shall be submitted for prefabricated vessels and tanks; and 2. Have the responsible design engineer submit a statement to the CBO that the proposed final design plans, specifications and calculations conform to all of the requirements set forth in the appropriate ASME Boiler and Pressure Vessel Code or other applicable codes.	At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of on-site fabrication or installation of any pressure vessel, the project owner shall submit to the CBO for design review and approval the above listed documents, including a copy of the signed and stamped engineer's certification, with a copy of the transmittal letter to the CPM. The project owner shall transmit to the CPM, in the Monthly Compliance Report following completion of any inspection, a copy of the transmittal letter conveying the CBO's and/or Cal-OSHA inspection approvals.	12/22/03		x		

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MECH-3	CONS	The project owner shall submit to the CBO for design review and approval the design plans, specifications, calculations, and quality control procedures for any heating, ventilating, air conditioning (HVAC), or refrigeration system. Packaged HVAC systems, where used, shall be identified with the appropriate manufacturer's data sheets. The project owner shall design and install all HVAC and refrigeration systems within buildings and related structures in accordance with the CBC and other applicable codes. Upon completion of any increment of construction, the project owner shall request the CBO's inspection and approval of said construction. The final plans, specifications, and calculations shall include approved criteria, assumptions, and methods used to develop the design. In addition, the responsible mechanical engineer shall sign and stamp all plans, drawings, and calculations and submit a signed statement to the CBO that the proposed final design plans, specifications, and calculations conform with the applicable LORS [2001 CBC, Section 108.7, Other Inspections; Section 106.3.4, Architect or Engineer of Record].	At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of construction of any HVAC or refrigeration system, the project owner shall submit to the CBO the required HVAC and refrigeration calculations, plans and specifications, including a copy of the signed and stamped statement from the responsible mechanical engineer certifying compliance with the CBC and other applicable codes, with a copy of the transmittal letter to the CPM.	12/22/03		x		
NOISE-1	PC	At least 15 days prior to the start of ground disturbance, the project owner shall notify all residents within one-half mile of the site and the linear facilities, by mail or other effective means, of the commencement of project construction. At the same time, the project owner shall establish a telephone number for use by the public to report any undesirable noise conditions associated with the construction and operation of the project. If the telephone is not staffed 24 hours per day, the project owner shall include an automatic answering feature, with date and time stamp recording, to answer calls when the phone is unattended. This telephone number shall be posted at the project site during construction in a manner visible to passersby. This telephone number shall be maintained until the project has been operational for at least one year.	Prior to ground disturbance, the project owner shall transmit to the CPM a statement, signed by the project manager, stating that the above notification has been performed, and describing the method of that notification, verifying that the telephone number has been established and posted at the site, and giving that telephone number.	12/22/03		x		
NOISE-2	Ongoing	Throughout the construction and operation of the project, the project owner shall document, investigate, evaluate, and attempt to resolve all project related noise complaints. The project owner or authorized agent shall: • Use the Noise Complaint Resolution Form (see Attachment 1), or functionally equivalent procedure acceptable to the CPM, to document and respond to each noise complaint; • Attempt to contact the person(s) making the noise complaint within 24 hours;	Within 5 days of receiving a noise complaint, the project owner shall file a copy of the Noise Complaint Resolution Form with the Riverside County Planning Department and the CPM, documenting the resolution of the complaint. If mitigation is required to resolve a complaint, and the complaint is not resolved within a 3-day period, the project owner shall submit an updated Noise Complaint Resolution Form when the mitigation is implemented.	12/22/03	x			
NOISE-3	PC	The project owner shall submit a noise control program plan to the CPM for review and approval. The noise control program shall be used to reduce employee exposure to high noise levels during construction and also to comply with applicable OSHA and Cal-OSHA standards.	At least 30 days prior to the start of ground disturbance, the project owner shall submit to the CPM the noise control program. The project owner shall make the program available to Cal-OSHA upon request.	12/22/03		x		

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NOISE-4	COMM	If a traditional, high-pressure steam or air blow process is employed, the project owner shall equip steam/air blow piping with a temporary silencer that quiets the noise of steam/air blows to no greater than 86 dBA measured at a distance of 100 feet. The noise level at the nearest residence produced by this operation must be less than a constant value of 48 dBA. The project owner shall conduct high pressure steam/air blows only during the hours of 8 a.m. to 5 p.m., unless the CPM agrees to longer hours based on a demonstration by the project owner that offsite noise impacts will not cause annoyance. If a low-pressure continuous steam blow or air blow process is employed, the project owner shall submit a description of this process, with expected noise levels and projected period of execution, to the CPM, who shall review the proposal with the objective of ensuring that the resulting noise levels from this process do not exceed 42 dBA hourly Leq at the most-affected residence. If the low-pressure process is approved by the CPM, the project owner shall implement it in accordance with the requirements of the CPM.	At least 15 days prior to the first high-pressure steam/air blow, the project owner shall submit to the CPM drawings or other information describing the temporary steam/air blow silencer and the noise levels expected, and a description of the steam/air blow schedule. At least 15 days prior to any low-pressure continuous steam/air blow, the project owner shall submit to the CPM drawings or other information describing the process, including the noise levels expected and the projected time schedule for execution of the process.	06/22/05		x- No steam blows		
NOISE-5	COMM	Prior to the first steam or air blow(s), the project owner shall notify all residents within one-half mile of the site, and the principal of the Romoland School, of the planned activity, and shall make the notification available to other area residents in an appropriate manner.	The notification may be in the form of letters to the area residences, telephone calls, fliers or other effective means. The notification shall include a description of the purpose and nature of the steam or air blow(s), the proposed schedule, the expected sound levels, and the explanation that it is a one-time operation and not a part of normal plant operations.	12/22/03		x- No steam blows		
NOISE-6	COMM	The project design and implementation shall include appropriate noise mitigation measures adequate to ensure that the noise level produced by operation of the project (including the gas compressor station) will not exceed an L50 of 45 dBA measured at any residence. No new pure tone components may be introduced. No single piece of equipment shall be allowed to stand out as a source of noise that draws legitimate complaints. Steam relief valves shall be adequately muffled to preclude noise that draws legitimate complaints. The measurement of power plant noise for the purposes of demonstrating compliance with this Condition of Certification may alternatively be made at a location, acceptable to the CPM, closer to the plant (e.g., 400 feet from the plant boundary) and this measured level then mathematically extrapolated to determine the plant noise contribution at the nearest residence. However, notwithstanding the use of this alternative method for determining the noise level, the character of the plant noise shall be evaluated at the nearest residence to determine the presence of pure tones or other dominant sources of plant noise. When the project first achieves a sustained output of 80 percent or greater of rated capacity, the project owner shall conduct a 25-hour community noise survey at Locations 1, 2, and 3 (Ex. 67, p. 5.6-5). The noise survey shall also include short-term measurement of one-third octave band sound pressure levels at each of the above locations to ensure that no new puretone noise components have been introduced. If the results from the two noise surveys (AFC vs. post-construction) indicate that the noise level due to the plant operations exceeds 45 dBA for any given hour during the 25-hour period, mitigation measures shall be implemented to reduce noise to a level of compliance with these limits. If the results from the two noise surveys (AFC vs. post-construction) indicate that pure tones are present, mitigation measures shall be implemented to eliminate the pure tones.	The post-construction survey shall take place within 30 days of the project first achieving a sustained output of 80 percent or greater of rated capacity. Within 15 days after completing the post-construction survey, the project owner shall submit a summary report of the survey to the Riverside County Planning Department and to the CPM. Included in the post-construction survey report will be a description of any additional mitigation measures necessary to achieve compliance with the above listed noise limits, and a schedule, subject to CPM approval, for implementing these measures. When these measures are in place, the project owner shall repeat the operational noise survey. Within 15 days of completion of installation of these measures, the project owner shall submit to the CPM a summary report of a new noise survey, performed as described above and showing compliance with this condition.	12/22/03			x	**IEEC proposes to complete an updated far field noise suvey per NOISE-6 after the installation of the 7HA.01 in Unit 2.**

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NOISE-7	COMM	Following the project first achieving a sustained output of 80 percent or greater of rated capacity, the project owner shall conduct an occupational noise survey to identify the noise hazardous areas in the facility. The survey shall be conducted by a qualified person in accordance with the provisions of Title 8, California Code of Regulations, sections 5095-5099 (Article 105) and Title 29, Code of Federal Regulations, section 1910.95. The survey results shall be used to determine the magnitude of employee noise exposure. The project owner shall prepare a report of the survey results and, if necessary, identify proposed mitigation measures that will be employed to comply with the applicable California and federal regulations.	Within 30 days after completing the survey, the project owner shall submit the noise survey report to the CPM. The project owner shall make the report available to OSHA and Cal-OSHA upon request.	12/22/03		x		
NOISE-8	CONS	Heavy equipment operation and noisy construction work shall be restricted to the times of day delineated below: Weekdays 7 a.m. to 7 p.m. Weekends and Holidays 8 a.m. to 5 p.m. Haul trucks and other engine-powered equipment shall be equipped with adequate mufflers. Haul trucks shall be operated in accordance with posted speed limits. Truck engine exhaust brake use shall be limited to emergencies. Horizontal drill rigs may be operated on a continuous basis, provided that the rigs are fitted with adequate mufflers and engine enclosures.	Prior to ground disturbance, the project owner shall transmit to the CPM in the first Monthly Construction Report a statement acknowledging that the above restrictions will be observed throughout the construction of the project	12/22/03		x		
PAL-1	PC	The project owner shall provide the CPM with the resume and qualifications of its Paleontological Resource Specialist (PRS) for review and approval. If the approved PRS is replaced prior to completion of project mitigation and report, the project owner shall obtain CPM approval of the replacement. The project owner shall submit to the CPM, to keep on file, resumes of the qualified Paleontological Resource Monitors (PRMs). If the PRMs are replaced, resumes of the replacement PRMs shall also be provided to the CPM. The PRS resume shall include the names and phone numbers of contacts. The resume shall also demonstrate to the satisfaction of the CPM, the appropriate education and experience to accomplish the required paleontological resource tasks. As determined by the CPM, the PRS shall meet the minimum qualifications for a vertebrate paleontologist as described in the Society of Vertebrate Paleontology (SVP) guidelines of 1995. The experience of the PRS shall include the following: 1. institutional affiliations or appropriate credentials and college degree; 2. ability to recognize and collect fossils in the field; 3. local geological and biostratigraphic expertise; 4. proficiency in identifying vertebrate and invertebrate fossils; and 5. in addition, the PRS shall have at least three years of paleontological resource mitigation and field experience in California, and at least one year of experience leading paleontological resource mitigation and field activities. The project owner shall ensure that the PRS obtains qualified paleontological resource monitors to monitor the project as necessary. Paleontologic resource monitors (PRMs) shall have the equivalent of the following qualifications: 1. BS or BA degree in geology or paleontology and one year experience monitoring in California; or 2. AS or AA in geology, paleontology, or biology and four years experience monitoring in California; or 3. Enrollment in upper division classes pursuing a degree in the fields of geology or paleontology and two years of monitoring experience in California.	At least 30 days prior to the start of ground disturbance, the project owner shall submit a resume and statement of availability of its designated PRS for on-site work. At least 20 days prior to ground disturbance, the PRS or project owner shall provide a letter with resumes naming anticipated monitors for the project and stating that the identified monitors meet the minimum qualifications for paleontological resource monitoring required by the condition. If additional monitors are obtained during the project, the PRS shall provide additional letters and resumes to the CPM. The letter shall be provided to the CPM no later than one week prior to the monitor beginning on-site duties. Prior to the termination or release of a PRS, the project owner shall submit the resume of the proposed new PRS to the CPM for review and approval. In an emergency, the project owner shall immediately notify the CPM to discuss the qualifications and approval of a short-term replacement while a permanent Paleontological Resource Specialist is proposed to the CPM for consideration.	12/22/03		x		

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PAL-2	PC	The project owner shall provide to the PRS and the CPM, for approval, maps and drawings showing the footprint of the power plant and all linear facilities. Maps shall identify all areas of the project where ground disturbance is anticipated. If the PRS requests enlargements or strip maps for linear facility routes, the project owner shall provide copies to the PRS and CPM. The site grading plan and the plan and profile drawings for the utility lines would normally be acceptable for this purpose. The plan drawings shall show the location, depth, and extent of all ground disturbances and may be 1 inch = 40 feet to 1 inch = 100 feet range. If the footprint of the power plant or linear facility changes, the project owner shall provide maps and drawings reflecting these changes to the PRS and CPM. If construction of the project will proceed in phases, maps and drawings may be submitted prior to the start of each phase. A letter identifying the proposed schedule of each project phase shall be provided to the PRS and CPM. Prior to work commencing on affected phases, the project owner shall notify the PRS and CPM of any construction phase scheduling changes. At a minimum, the project owner shall ensure that the PRS consults weekly with the project superintendent or construction field manager to confirm area(s) to be worked during the next week, until ground disturbance is completed.	At least 30 days prior to the start of ground disturbance, the project owner shall provide the maps and drawings. If there are changes to the footprint of the project, revised maps and drawings shall be provided at least 15 days prior to the start of ground disturbance. If there are changes to the scheduling of the construction phases, the project owner shall submit a letter to the CPM within 5 days of identifying the changes.	12/22/03		x		
PAL-3	PC	The project owner shall ensure that the PRS prepares, and the project owner shall submit to the CPM for review and approval, a Paleontological Resources Monitoring and Mitigation Plan (PRMMP) to identify general and specific measures to minimize potential impacts to significant paleontological resources. Approval of the PRMMP by the CPM shall occur prior to any ground disturbance. The PRMMP shall function as the formal guide for monitoring, collecting, and sampling activities and may be modified with CPM approval. This document shall be used as a basis for discussion in the event that on-site decisions or changes are proposed. Copies of the PRMMP shall reside with the PRS, each monitor, the project owner's on-site manager, and the CPM. The PRMMP shall be developed in accordance with the guidelines of the Society of the Vertebrate Paleontology (SVP, 1995) and shall include, but not be limited to, the following: • Assurance that the performance and sequence of project-related tasks, such as any literature searches, pre-construction surveys, worker environmental training, fieldwork, flagging or staking; construction monitoring; mapping and data recovery; fossil preparation and collection; identification and inventory; preparation of final reports; and transmittal of materials for curation will be performed according to the PRMMP procedures; • Identification of the person(s) expected to assist with each of the tasks identified within the PRMMP and all Conditions for Certification; • A thorough discussion of the anticipated geologic units expected to be encountered, the location and depth of the units relative to the project when known, and the known sensitivity of those units based on the occurrence of fossils either in that unit or in correlative units; • An explanation of why, how, and how much sampling is expected to take place and in what units. Include descriptions of different sampling procedures that shall be used for fine-grained and coarsegrained beds; • A discussion of the locations of where the monitoring of project construction activities is deemed necessary, and a proposed schedule for the monitoring; • A discussion of the procedures to be followed in the event of a significant fossil discovery, including notifications; • A discussion of equipment and supplies necessary for collection of fossil materials and any specialized equipment needed to prepare, remove, load, transport, and analyze large-sized fossils or extensive fossil deposits; • Procedures for inventory, preparation, and delivery for curation into a retrievable storage collection in a public repository or museum, which meets the Society of Vertebrate Paleontology standards and requirements for the	At least 30 days prior to ground disturbance, the project owner shall provide a copy of the PRMMP to the CPM. The PRMMP shall include an affidavit of authorship by the PRS, and acceptance of the project owner evidenced by a signature.	12/22/03		x		

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PAL-4	PC	Prior to ground disturbance and for the duration of construction, the project owner and the PRS shall prepare and conduct weekly CPM-approved training for all project managers, construction supervisors, and workers who are involved with or operate ground disturbing equipment or tools. Workers shall not excavate in sensitive units prior to receiving CPM-approved worker training. Worker training shall consist of an initial in-person PRS training during the project kick-off for those mentioned above. Following initial training, a CPM-approved video or in-person training may be used for new employees. The training program may be combined with other training programs prepared for cultural and biological resources, hazardous materials, or any other areas of interest or concern. The Worker Environmental Awareness Program (WEAP) shall address the potential to encounter paleontological resources in the field, the sensitivity and importance of these resources, and the legal obligations to preserve and protect such resources. The training shall include: • A discussion of applicable laws and penalties under the law; • For locations of high sensitivity, good quality photographs or physical examples of vertebrate fossils that may be expected in the area shall be provided; • Information that the PRS or PRM has the authority to halt or redirect construction in the event of a discovery or unanticipated impact to a paleontological resource; • Instruction that employees are to halt or redirect work in the vicinity of a find and to contact their supervisor and the PRS or PRM; • An informational brochure that identifies reporting procedures in the event of a discovery, a Certification of Completion of WEAP form signed by each worker indicating that they have received the training; and a sticker that shall be placed on hard hats indicating that environmental training has been completed.	At least 30 days prior to ground disturbance, the project owner shall submit the proposed WEAP including the brochure with the set of reporting procedures the workers are to follow. At least 30 days prior to ground disturbance, the project owner shall submit the script and final video to the CPM for approval if the project owner is planning on using a video for interim training. If an alternate paleontological trainer is requested by the owner, the resume and qualifications of the trainer shall be submitted to the CPM for review and approval. Alternate trainers shall not conduct training prior to CPM authorization. The project owner shall provide in the Monthly Compliance Report (MCR) the WEAP copies of the Certification of Completion forms with the names of those trained and the trainer or type of training offered that month. The MCR shall also include a running total of all persons who have completed the training to date.	12/22/03		x		

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PAL-5	CONS	The project owner shall ensure that the PRS and PRM(s) monitor, consistent with the PRMMP, all construction-related grading, excavation, trenching, and augering in areas where potentially fossil-bearing materials have been identified. In the event that the PRS determines full time monitoring is not necessary in locations that were identified as potentially fossil-bearing in the PRMMP, the project owner shall notify and seek the concurrence of the CPM. The project owner shall ensure that the PRS and PRM(s) have the authority to halt or redirect construction if potentially significant paleontological resources are encountered in the judgment of the PRS. The project owner shall ensure that there is no interference with monitoring activities unless directed by the PRS. Monitoring activities shall be conducted as follows: 1) Any change of monitoring different from the accepted schedule presented in the PRMMP shall be proposed in a letter or email from the PRS and the project owner to the CPM prior to the change in monitoring. The letter or email shall include the justification for the change in monitoring and be submitted to the CPM for review and approval. 2) The project owner shall ensure that the PRM(s) keeps a daily log of monitoring of paleontological resource activities. The PRS may informally discuss paleontological resource monitoring and mitigation activities with the CPM at any time. 3) The project owner shall ensure that the PRS immediately notifies the CPM of any incidents of non-compliance with any paleontological resources Conditions of Certification. The PRS shall recommend corrective action to resolve the issues or achieve compliance with the Conditions of Certification. 4) For any significant paleontological resources encountered, either the project owner or the PRS shall notify the CPM immediately (no later than the following morning after the find, or Monday morning in the case of a weekend) of any halt of construction activities. The project owner shall ensure that the PRS prepares a summary of the monitoring and other paleontological activities that will be placed in the Monthly Compliance Reports. The summary shall include the name(s) of PRS or monitor(s) active during the month; general descriptions of training and monitored construction activities and general locations of excavations, grading, etc. A section of the report shall include the geologic units or subunits encountered; descriptions of sampling within each unit; and a list of fossils identified in the field. A final section of the report shall address any issues or concerns about the project relating to paleontologic monitoring including any incidents of non-compliance and any changes to the monitoring plan that have been approved by the CPM. If no monitoring took	The project owner shall ensure that the PRS submits the summary of monitoring and paleontological activities in the MCR.	12/22/03		x		
PAL-6	CONS	The project owner, through the designated PRS, shall ensure the collection, preparation for analysis, analysis, identification and inventory, the preparation for curation, and the delivery for curation of all significant paleontological resource materials encountered and collected during the monitoring, data recovery, mapping, and mitigation activities related to the project.	The project owner shall maintain in their compliance file copies of signed contracts or agreements with the designated PRS and other qualified research specialists. The project owner shall maintain these files for a period of three years after completion and approval of the CPM-approved PRR. The project owner shall be responsible to pay any curation fees required by the museum for fossils collected and curated as a result of paleontological monitoring and mitigation.	12/22/03		x		
PAL-7	CONS	The project owner shall ensure preparation of a Paleontological Resources Report (PRR) by the designated PRS. The PRR shall be prepared following completion of the ground disturbing activities. The PRR shall include an analysis of the collected fossil materials and related information and submitted to the CPM for review and approval. The report shall include, but not be limited to, a description and inventory of recovered fossil materials; a map showing the location of paleontological resources encountered; determinations of sensitivity and significance; and a statement by the PRS that project impacts to paleontological resources have been mitigated.	Within 90 days after completion of ground disturbing activities, including landscaping, the project owner shall submit the Paleontological Resources Report under confidential cover to the CPM.	12/22/03		x		
Public Health-1	CONS	The project owner shall develop and implement a cooling tower Biocide Use, Biofilm Prevention, and Legionella Control Program to ensure that cooling tower bacterial growth is controlled. The program shall be consistent with CEC guidelines or the Cooling Technology Institute guidelines.	At least 30 days prior to the commencement of cooling tower operations, the project owner shall provide the Biocide Use, Biofilm Prevention, and Legionella Control Program to the CPM for review and approval.	12/22/03		x		

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SOCIO-1	CONS	The project owner shall pay the one-time statutory school development fee as required at the time of filing for the in-lieu building permit with the Riverside County Building Department.	The project owner shall provide proof of payment of the statutory development fee in the Monthly Compliance Report following the payment.	12/22/03		x		
SOIL & WATER-1	PC	Prior to beginning any site mobilization activities for any project element, the project owner shall obtain Compliance Project Manager (CPM) approval for a site-specific Erosion and Sedimentation Control Plan (ESCP) that addresses all project elements. The ESCP shall be consistent with the standards normally required in Riverside County's Grading and Excavation Permits for all project elements, including a Geotechnical Soils Report and specification of any areas for import or export of soils. The plan shall address revegetation and be consistent with the grading and drainage plan as required by Condition of Certification CIVIL 1.	No later than 60 days prior to the start of any site mobilization for any project element, the project owner shall submit the ESCP to the CPM for review and approval. No later than 60 days prior to start of any site mobilization, the project owner shall submit a copy of the ESCP to the County of Riverside Building and Safety Department for review and request any comments be provided to the CPM within 30 days.	12/22/03		x		
SOIL & WATER-2	PC	Prior to beginning site mobilization, the project owner shall submit a Notice of Intent for construction under the General National Pollutant Discharge Elimination System (NPDES) Permit for Discharges of Storm Water Associated with Construction Activity to the State Water 236 Resources Control Board (SWRCB). The project owner shall develop and implement a Storm Water Pollution Prevention Plan (SWPPP) for the construction of the entire project. The SWPPP shall be submitted to Riverside County for review and comment, and to the CPM for review and approval. The SWPPP shall include a final construction drainage design consistent with the criteria specified by County of Riverside, and specify Best Management Practices (BMPs) for all on- and off-site IEEC project facilities. BMPs shall control soil erosion from storm water drainage below the detention pond and from storm water discharge of the eastern boundary interception ditch. Conditions of Certification BIO-7 and BIO-8 address requirements for 401 Water Quality Certification from the Regional Water Quality Control Board and a Section 404 Permit from the Army Corps of Engineers.	No later than 60 days prior to the start of site mobilization for any project element, the SWPPP for Construction Activity, and a copy of the Notice of Intent for construction under the General NPDES Permit for Discharges of Storm Water Associated with Construction Activity filed with the SWRCB, shall be submitted by the project owner to the County of Riverside Building and Safety Department for comments and to the CPM for approval. Approval of the SWPPP must be received from the CPM prior to site mobilization.	12/22/03		x		
SOIL & WATER-3	COMM	Prior to project commercial operation, the project owner shall submit a Notice of Intent for operation under the General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity to the State Water Resources Control Board (SWRCB). The project owner shall develop and implement a Storm Water Pollution Prevention Plan (SWPPP) for the operation of the project. The SWPPP shall be submitted to Riverside County for review and comment, and to the CPM for review and approval. The SWPPP shall include final operating drainage design consistent with the criteria specified by the County of Riverside**, including those criteria relating to any adjacent flood control channels,** and specify BMPs and monitoring requirements for the IEEC project facilities. BMPs shall control soil erosion from drainage of storm water below the **vegetated swales or detention pond** and from storm water discharge in the eastern boundary interception ditch Conditions of Certification **BIO-7** and **BIO-8** address requirements for 401 Water Quality Certification from the Regional Water Quality Control Board and a Section 404 Permit from the Army Corps of Engineers.	No later than 60 days prior to the start of commercial operation for any project element, the SWPPP for Industrial Activity and a copy of the Notice of Intent for operating under the General NPDES Permit for Discharges of Storm Water Associated with Industrial Activity filed with the SWRCB, shall be submitted by the project owner to the County of Riverside Building and Safety Department for comments, and to the CPM for approval. Approval of the SWPPP must be received from the CPM prior to commercial operation.	12/22/03		x - IEEC has an approved NONA with Riverside County Storm Water Resources Board		

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SOIL & WATER-4	OPS	The project owner shall use tertiary-treated water supplied from Eastern Municipal Water District's (EMWD's) Recycled Water System as its primary source of water for cooling, process, and landscape irrigation. Based on EMWD's projected availability of recycled water supply to IEEC, it is recognized that EMWD may need to augment its recycled water system with raw water during the early years of IEEC project operation. The project owner shall obtain copies of project water use records derived from EMWD's recycled water revenue meters. In addition, the project owner shall obtain copies of meter records or other appropriate records documenting methodology used by EMWD for billing purposes to quantify EMWD's raw water augmentation to its recycled water system at the Perris Water Treatment Plant for indirect supply to IEEC. The project owner shall prepare an annual summary, which shall include the monthly range and monthly average of daily water usage in gallons per day, and total water used on a monthly and annual basis in acre-feet. The annual summary shall distinguish sources and uses of water according to recycled water supplied for IEEC cooling, process, and landscape irrigation purposes, and raw water augmenting EMWD's recycled water system at the Perris Water Treatment Plant. For years subsequent to the initial year of IEEC operation, the annual summary shall also include the yearly range and yearly average water use.	The project owner shall submit a water use summary report to the CPM in the Annual Compliance Report (ACR) for the life of the project. . Any significant changes in the water supply for the project 's use of recycled and/or raw water for cooling, process or landscape uses shall be specified in writing to the CPM at least 60 days prior to the proposed effective date of the change.	12/22/03	x			
SOIL & WATER-5	OPS	The project owner shall use recycled water to the fullest extent possible. In the initial years of operation, EMWD may need to supplement recycled water with raw imported water in amounts that will not impact the adequacy of supplies of imported water to others. The project owner must develop a mechanism with EMWD to determine the extent to which imported water is indirectly used to supplement recycled water to supply IEEC, and report annually to the CPM the actual amounts of raw water indirectly supplied to IEEC. The project owner shall work cooperatively with EMWD to ensure that such indirect use does not exceed the amounts shown in the following table, except under the circumstances specified below.Excerpt from SOIL AND WATER Table 8, Maximum Limits of RAW Water Augmentation to EMWD's Recycled Water System Attributable to IEEC (acre-feet/year) (Ex. 67, 5.9-26.) Year: Maximum Permissible Limits of Raw Water Augmentation Attributable to IEEC 2005: 1,000 2006: 800 2007: 600 2008: 400 2009: 200 2010: 100 2011 and after: 100 If a recycled water supply deficiency occurs due to an act of God, a natural disaster, an unforeseen emergency, or other unforeseen circumstances outside the control of the project owner, additional raw water in excess of these amounts can be used. If one of the aforementioned unavoidable circumstances should occur, the CPM, project owner and EMWD shall confer and determine how to restore the recycled water supply as soon as practicable.	The project owner shall submit a water use summary to the CPM in the ACR for the life of the project. Any significant change in the water supply for the project during construction or operation of the plant shall be specified in writing to the CPM at least 60 days prior to the proposed effective date of the change, and shall be subject to conferring with EMWD and the CPM. The project owner shall track its raw water use on a monthly basis using EMWD's meter readings or other appropriate methodology used for EMWD's billing purposes in order to notify the CPM immediately upon exceeding, or upon forecasting to exceed, the maximum raw water use as specified above.	12/22/03	x			

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SOIL & WATER-6	OPS	Prior to project commercial operation, the project owner shall submit an executed and final Service Agreement with EMWD. The Service Agreement shall address recycled water and raw water supplemented for process, cooling and landscape irrigation, potable water or domestic and fire protection, process and sanitary wastewater services. The Service Agreement shall include the Industrial Waste Discharge Permit and Non-Reclaimable Wastewater Discharge Permit as issued by EMWD.	At least 30 days prior to project commercial operation, the project owner shall submit to the CPM a copy of the executed Service Agreement for IEEC between the project owner and EMWD for obtaining recycled water, supplemental raw water, potable water, process wastewater discharge and sanitary wastewater service.	12/22/03		x		
SOIL & WATER-7	COMM	The Ethanac Wash floodplain is located near the southern boundary of the IEEC Site. Construction of the IEEC shall remain outside of the FEMA floodplain shown on the effective Riverside County Flood Insurance Rate Map (FIRM), Panel 2085 of 3600. The project owner shall notify the CPM of any Conditional Letter of Map Revision (CLOMR) requests to modify the Ethanac Wash Floodplain. The project owner shall review the CLOMR request for potential impacts to the IEEC Site. The project owner will provide the CPM evidence that the IEEC property is protected from flooding due to floodplain modifications. The property owner shall submit to the CPM any Letter of Map Revision (LOMR) issued from FEMA resulting in a change to the effective FIRM where FEMA has requested review by the project owner as a potentially affected owner. The project owner shall verify that the IEEC Site is outside of the special C197flood hazard boundary and elevated above the base flood elevations.	Prior to initiation of commercial operation of the IEEC, the project owner shall submit to the CPM evidence of its review of documentation requesting changes to the Ethanac Wash Floodplain. The project owner shall copy the CPM on their acknowledgment letter to the CLOMR or LOMR applicant stating that the floodplain modification project will not impact the IEEC site. The project owner shall submit to the CPM evidence of the LOMR from FEMA, and a copy of the revised or annotated FIRM showing the IEEC Site. The Annual Compliance Report shall report any floodplain changes that have a potential to impact the IEEC Site during operations.	06/22/05	x			
SOIL & WATER-8	PC	Existing Condition of Certification Soil and Water-8 was inadvertently shown in strike through text in the Staff Analysis, suggesting that it should be deleted. As the narrative in the Staff Analysis indicates at page 92, it is Staff's intention and recommendation that the existing condition continue to apply to the amended project. Therefore, existing condition Soil and Water-8 should remain as a Condition of Certification in the form adopted in the original Commission Decision: Prior to site mobilization, the project owner shall pay a Flood Mitigation Fee in the amount assessed in accordance with Riverside County's Homeland/Romoland Area Drainage Plan (ADP) to assist in providing revenue to establish adequate community drainage facilities. The amount of the fee for industrial development shall be calculated on the basis of the prevailing Area Drainage Plan fee rate multiplied by the area of the new development.	Prior to site mobilization, the project owner shall submit to the CPM, documentation that payment has been made to the County of Riverside for the Flood Mitigation Fee.	06/20/05		x		

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STRUC-1	CONS	Prior to the start of any increment of construction of any major structure or component listed in Table 1 of Condition of Certification GEN- 2, above, the project owner shall submit to the CBO for design review and approval the proposed lateral force procedures for project structures and the applicable designs, plans, and drawings for project structures. Proposed lateral force procedures, designs, plans and drawings shall be those for the following items (from Table 1, above): 1. Major project structures; 2. Major foundations, equipment supports and anchorage; 3. Large field fabricated tanks; 4. **Turbine/generator pedestal**; and+C195 5. Switchyard structures. Construction of any structure or component shall not commence until the CBO has approved the lateral force procedures to be employed in designing that structure or component. The project owner shall: 1. Obtain approval from the CBO of lateral force procedures proposed for project structures; 2. Obtain approval from the CBO for the final design plans, specifications, calculations, soils reports, and applicable quality control procedures. If there are conflicting requirements, the more stringent shall govern (i.e., highest loads or lowest allowable stresses shall govern). All plans, calculations and specifications for foundations that support structures shall be filed concurrently with the structure plans, calculations, and specifications [2001 CBC, Section 108.4, Approval Required]; 3. Submit to the CBO the required number of copies of the structural plans, specifications, calculations and other required documents of the designated major structures at least 60 days (or a lesser number of days mutually agreed to by the project owner and the CBO) prior to the start of on-site fabrication and installation of each structure, equipment support, or foundation [2001 CBC, Section 106.4.2, Retention of plans; and Section 106.3.2, Submittal documents]; and 4. Ensure that the final plans, calculations, and specifications clearly reflect the inclusion of approved criteria, assumptions, and methods used to develop the design. The final designs, plans, calculations and specifications shall be signed and stamped by the responsible design engineer [2001 CBC, Section 106.3.4, Architect or Engineer of Record].	At least 30 days (or project owner and CBO approved alternative timeframe) prior to the start of any increment of construction of any structure or component listed in Table 1 of Condition of Certification GEN-2 above, the project owner shall submit to the CBO, with a copy to the CPM, the responsible design engineer's signed statement that the final design plans, specifications, and calculations conform with all of the requirements set forth in the Energy Commission's Decision. If the CBO discovers non-conformance with the stated requirements, the project owner shall resubmit the corrected plans to the CBO within 20 days of receipt of the nonconforming submittal, with a copy of the transmittal letter to the CPM. The project owner shall submit to the CPM a copy of a statement from the CBO that the proposed structural plans, specifications, and calculations have been approved and are in conformance with the requirements set forth in the applicable engineering LORS.	12/22/03			x	**STRUCT-1 #4: The alteration, repair or addition to the existing foundation will meet the requirements of Chapter 34 of CBC 2013. The replacement will be designed and inspection will be by California PE. IEEC believes this meets the intent of CBO certification for the 7HA.01 installation.**
STRUC-2	CONS	The project owner shall submit to the CBO the required number of sets of the following documents related to work that has undergone CBO design review and approval: 1. Concrete cylinder strength test reports (including date of testing, date sample taken, design concrete strength, tested cylinder strength, age of test, type and size of sample, location and quantity of concrete placement from which sample was taken, and mix design designation and parameters); 2. Concrete pour sign-off sheets; 3. Bolt torque inspection reports (including location of test, date, bolt size, and recorded torques); 4. Field weld inspection reports (including type of weld, location of weld, inspection of non-destructive testing (NDT) procedure and results, welder qualifications, certifications, qualified procedure description or number (ref: AWS); and 5. Reports covering other structural activities requiring special inspections shall be in accordance with the 2001 CBC, Chapter 17, Section 1701, Special Inspections; Section 1701.5, Type of Work (requiring special inspection); Section 1702, Structural Observation and Section 1703, Nondestructive Te	If a discrepancy is discovered in any of the above data, the project owner shall, within five days, prepare and submit an NCR describing the nature of the discrepancies to the CBO, with a copy of the transmittal letter to the CPM [2001 CBC, Chapter 17, Section 1701.3, Duties and Responsibilities of the Special Inspector]. The NCR shall reference the Condition(s) of Certification and the applicable CBC chapter and section. Within five days of resolution of the NCR, the project owner shall submit a copy of the corrective action to the CBO and the CPM. The project owner shall transmit a copy of the CBO's approval or disapproval of the corrective action to the CPM within 15 days. If disapproved, the project owner shall advise the CPM, within five days, the reason for disapproval, and the revised corrective action to obtain CBO's approval.	12/22/03			x	**IEEC will comply with STRUC-2 with respect to the 7HA.01 installation**

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STRUC-3	CONS	The project owner shall submit to the CBO design changes to the final plans required by the 2001 CBC, Chapter 1, Section 106.3.2, Submittal documents and Section 106.3.3, Information on plans and specifications, including the revised drawings, specifications, calculations, and a complete description of, and supporting rationale for, the proposed changes, and shall give the CBO prior notice of the intended filing.	On a schedule suitable to the CBO, the project owner shall notify the CBO of the intended filing of design changes, and shall submit the required number of sets of revised drawings and the required number of copies of the other above-mentioned documents to the CBO, with a copy of the transmittal letter to the CPM. The project owner shall notify the CPM, via the Monthly Compliance Report, when the CBO has approved the revised plans.	12/22/03		x		
STRUC-4	CONS	Tanks and vessels containing quantities of toxic or hazardous materials exceeding amounts specified in Chapter 3, Table 3-E of the 2001 CBC shall, at a minimum, be designed to comply with the requirements of that chapter.	At least 30 days (or project owner and CBO approved alternate timeframe) prior to the start of installation of the tanks or vessels containing the above specified quantities of toxic or hazardous materials, the project owner shall submit to the CBO for design review and approval final design plans, specifications, and calculations, including a copy of the signed and stamped engineer's certification.	12/22/03		x		
TLSN-1	CONS	The project owner shall ensure that the proposed interconnection transmission lines are constructed according to the requirements of CPUC's GO-95, applicable requirements of Title 8, Section 2700 et seq. of the California Code of Regulations, and SCE's EMF reduction guidelines arising from CPUC Decision 93-11-013.	Thirty days before starting construction of the IEEC's transmission line or related structures and facilities, the project owner shall submit to the Energy Commission's Compliance Project Manager (CPM) a letter signed by a transmission line owner's responsible manger affirming that the overhead section will be constructed according to the requirements GO-95, applicable requirements of Title 8, Section 2700 et seq. of the California Code of Regulations, and SCE's EMF-reduction guidelines arising from CPUC Decision 93-11-013.	12/22/03		x		
TLSN-2	CONS	The project owner shall ensure that all metallic objects along the route of the overhead section are grounded according to industry standards. Those portions of the overhead section that are transferred to a regulated public utility that is subject to a substantively similar requirement shall no longer be subject to this condition.	At least 30 days before the lines are energized, the project owner shall transmit to the CPM a letter confirming compliance with this condition.	12/22/03		x		
TLSN-3	Ongoing	The project owner shall take the resonable steps to resolve any complaints of interference with radio or television signals from operation of the proposed line.	deleted	11/13/05		x		
TLSN-4	OPS	deleted		11/13/05				
TRANS-1	CONS	The project owner shall comply with California Department of Transportation (Caltrans) and Riverside County limitations on vehicle sizes and weights. Overload Limit Permits will be obtained from Caltrans as necessary. In addition, the project owner or its contractor shall obtain other necessary transportation permits from Caltrans and all relevant jurisdictions for both rail and roadway use.	In the Monthly Compliance Reports, the project owner shall in the Monthly Compliance Reports, the project owner shall submit copies of any oversize and overweight transportation permits received during that reporting period. In addition, the project owner shall retain copies of these permits and supporting documentation in its compliance file for at least six months after the start of commercial operation.	12/22/03			x	**IEEC will provide documentation of oversize and/or overweight transportation permits to the CPM within 14 days of completion of heavy haul activities during the HA.01 installation project.**
TRANS-2	CONS	The project owner or its contractor shall comply with California Department of Transportation (Caltrans), City of Perris, and Riverside County limitations for encroachment into public rights-of-way and shall obtain necessary encroachment permits from Caltrans, Riverside County, City of Perris, and all other relevant jurisdictions.	In the Monthly Compliance Reports, the project owner shall submit copies of any encroachment permits received during that reporting period. In addition, the project owner shall retain copies of these permits and supporting documentation in its compliance file for at least six months after the start of commercial operation.	12/22/03			x	**IEEC will provide documentation of encroachment permits to the CPM within 14 days of completion of subject activities during the HA.01 installation project.**

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TRANS-3	CONS	The project owner shall ensure that all federal and state regulations for the transport of hazardous materials are observed.	The project owner shall include in its Monthly Compliance Reports copies of all permits and licenses acquired by the project owner and/or subcontractors concerning the transport of hazardous materials.	12/22/03		x		
TRANS-4	PC	Following completion of project construction of the IEEC and all linear facilities, the project owner shall restore Ethanac, Matthews, and Palomar Roads to their pre-construction condition unless the damage is shown not to be a result of IEEC construction activities. Protocol: Prior to start of site preparation or earth moving activities, the project owner shall photograph, videotape, or digitally record images of Ethanac Road from I-215 to Matthews Road, Matthews Road from Ethanac Road to Palomar Road, and Palomar Road from Matthews Road to SR 74. The project owner shall provide the CEC Compliance Project Manager (CPM), Riverside County, and Caltrans (as necessary) a copy of these images. At least 60 days prior to start of site preparation or earth moving activities, the project owner shall also notify Caltrans about the schedule for project construction. The purpose of this notification is to allow Caltrans to postpone any planned roadway resurfacing and/or improvement projects until after the project construction has taken place and to coordinate construction related activities associated with other projects.	Within 30 days after completion of project construction, theWithin 30 days after completion of project construction, the project owner shall meet with the CPM, Riverside County, and Caltrans (as needed) to determine and receive approval for the actions necessary and schedule to complete the repair of identified sections of public roadways to original or as near original condition as possible. The project owner shall provide to the CPM a letter from Riverside County stating the County's satisfaction with the road improvements.	12/22/03		x		
TRANS-5	PC	During construction of the power plant and all related facilities, the project owner shall ensure that all project-related parking occurs in designated parking areas.	At least 45 days prior to start of site preparation or earth moving activities, the project owner shall submit a parking and staging plan for all phases of project construction to Riverside County for review and comment, and to the CPM for review and approval.	12/22/03		x		
TRANS-6	PC	The project owner shall develop a construction traffic control plan that outlines what measures need to be taken on a month-to-month basis with input from Riverside County, Caltrans and the CPM. Specifically, the construction Contractor shall be required to prepare a traffic control plan and implementation program that addresses timing of heavy equipment and building material deliveries; employee trip reduction; and signing, lighting, and traffic control device placement. The following specific best management practices will be incorporated into the construction traffic control plan: Truckloads will not exceed legal limits. Loads of material (i.e. excavated soil) will either be enclosed by vehicle covers, or wetted and loaded in the truck to provide at least one foot of free board and prevent wind blowing materials out of the truck. Trucks and trailers will be swept clean or hosed after unloading and before entering a public roadway. Mufflers, brakes, and all loose items on trucks will be maintained to minimize noise and ensure safe operation. Truck operations will be kept to quietest operating speeds. Drivers will be advised to avoid downshifting while driving through or near residential communities. Traffic control will be coordinated with BNSF to ensure motorists are aware of any railroad trips during construction. Traffic control will be coordinated with any construction in the vicinity of the project on the proposed Hemet to Corona/Lake Elsinore transportation corridor.	At least 30 days prior to start of site preparation or earth movingAt least 30 days prior to start of site preparation or earth moving activities, the project owner shall provide the plan to Riverside County and Caltrans for review and comment, and to the CPM for review and approval.	12/22/03		x		
TRANS-7	PC	During construction and operation of the IEEC, the project owner and contractors shall ensure that all project-related traffic travels on Antelope Road from the project site to Ethanac Road in order to access SR 74, I-215, and other areas. Project traffic shall not travel on Antelope Road north of Ethanac Road so as to avoid the school located on Antelope Road near Monroe Avenue.	At least 45 days prior to start of site preparation or earth moving activities, the project owner shall provide a traffic routing plan for all phases of project construction and operation to Riverside County and Caltrans for review and comment, and to the CPM for review and approval.	12/22/03		x		

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TRANS-8	PC	The project owner and contractor shall gravel the currently unpaved section of Antelope Road between Ethanac Road and the project site prior to commencing construction. Surfacing that provides adequate truck turning radii shall be in place to help facilitate safe truck-turning movements. Upon completion of construction, the project owner and contractor shall pave and extend Antelope Road and build a road for circulation within the IEEC site. Antelope Road's 24-foot wide, 1,000-foot long extension from its current terminus south of Ethanac Road will be used to provide normal access to the IEEC site. Within the IEEC site, a 20-foot wide loop road shall provide internal circulation.	At least 45 days prior to start of site preparation or earth moving activities, the project owner shall submit plans for modifications to Antelope and San Jacinto Roads to Riverside County for review and comment, and to the CPM for review and approval. The project owner shall provide to the CPM a letter from Riverside County stating the County's satisfaction with the plans. In addition to the letter, the project owner shall provide a copy of the Signal Mitigation Program fee payment to the CPM. Within 30 days after completion of project construction, the project owner shall meet with the CPM, Riverside County and Caltrans (as needed) to determine and receive approval for the actions necessary to complete the Antelope Road extension and internal circulation. The project owner shall submit to the CPM a letter from Riverside County stating the County's satisfaction with the completed road improvements.	12/22/03		x		
TSE-1	CONS	The project owner shall ensure that the design, construction and operation of the proposed transmission facilities shall conform to all applicable LORS including the requirements 1a) through 1f) listed below. The substitution of Compliance Project Manager (CPM) approved "equivalent" equipment and an equivalent substation configuration is acceptable. a) The power plant switchyard and outlet lines shall meet or exceed the electrical, mechanical, civil and structural requirements of SCE interconnection standards, Cal-ISO Interconnection Requirements, SCE's Detailed Facilities Study (DFS), CPUC General Orders 95 (GO-95) or National Electric Safety Code (NESC), Title 8 of the California Code of Regulations, Articles 35, 36 and 37 of the "High Voltage Electric Safety Orders", National Electric Code (NEC), and related industry standards. b) Breakers and buses in the power plant switchyard and other switchyards, where applicable, shall be sized to comply with a short-circuit analysis. c) Outlet line crossings and line parallels with transmission and distribution facilities shall be coordinated with the transmission line owner and comply with the owner's standards. d) Termination facilities shall comply with applicable interconnection standards. e) The project conductors shall be sized to accommodate the full output from the project. f) The project owner shall provide: I. Any modified Detailed Facility Study (DFS) including a description of facility upgrades, operational mitigation measures, and/or Remedial Action Scheme (RAS) or Special Protection System (SPS) sequencing and timing if applicable, II. The executed Facility Interconnection Agreement with SCE.	At least 30 days prior to the start of grading of the power plant switchyard or transmission facilities, the project owner shall submit to the CPM for approval: Electrical one line diagrams signed and sealed by a registered professional electrical engineer in responsible charge (or other approval acceptable to the CPM), a route map, and an engineering description of equipment and the configurations covered by the requirements 1a) through 1f) above. The Detailed Facilities Study including a description of facility upgrades, operational mitigation measures and/or RAS or SPS, and the Utility Interconnection Agreement and the Cal-ISO Participating Generator agreement (if either one are not otherwise provided to the Commission previously). Substitution of equipment and substation configurations shall be identified and justified by the project owner for CPM approval.	12/22/03		x		
TSE-2	CONS	The project owner shall inform the CPM of any impending changes that may not conform to the requirements 1a) through 1f) of TSE- 1 and have not received CPM approval, and request approval to implement such changes. A detailed description of the proposed change and complete engineering, environmental, and economic rationale for the change shall accompany the request. Construction involving changed equipment or substation configurations shall not begin without prior written approval of the changes by the CPM.	At least 30 days prior to the construction of the power plant switchyard and transmission facilities, the project owner shall inform the CPM of any impending changes that may not conform to requirements 1a) through 1f) of TSE-1 and request approval to implement such changes.	12/22/03		x		

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TSE-3	CONS	The project owner shall be responsible for the inspection of the transmission facilities during project construction, and any subsequent CPM approved changes thereto, to ensure conformance with CPUC GO- 95 or NESC, Title 8 of the California Code of Regulations, Articles 35, 36 and 37 of the "High Voltage Electric Safety Orders", SCE's interconnection standards, NEC, related industry standards, and these conditions. In case of non-conformance, the project owner shall inform the CPM in writing, within 10 days of discovering such non-conformance, and describe the corrective actions to be taken.	Within 60 days after first synchronization of the project to theWithin 60 days after first synchronization of the project to the grid, the project owner shall transmit to the CPM an engineering description(s) and one-line diagrams of the "as built" facilities signed and sealed by the registered electrical engineer in responsible charge (or other verification acceptable to the CPM, such as a letter stating that the attached diagrams have been verified by the engineer). A statement attesting to conformance with CPUC GO-95 or NESC, Title 8 of the California Code of Regulations, Articles 35, 36 and 37 of the "High Voltage Electric Safety Orders", SCE's interconnection standards, NEC, related industry standards, and these conditions.	12/22/03		x		
TSE-4	COMM	The project owner shall provide the following Notice to the California Independent System Operator (Cal-ISO) prior to synchronizing the facility with the California transmission system: 1. At least one week prior to synchronizing the facility with the grid for testing, provide the Cal-ISO a letter stating the proposed date of synchronization; and 2. At least one business day prior to synchronizing the facility with the grid for testing, provide telephone notification to the ISO Outage Coordination Department.	The project owner shall provide copies of the Cal-ISO letter to the CPM when it is sent to the Cal-ISO one week prior to initial synchronization with the grid. The project owner shall contact the Cal-ISO Outage Coordination Department, Monday through Friday, between the hours of 0700 and 1530 at (916) 351-2300 at least one business day prior to synchronizing the facility with the grid for testing. A report of conversation with the Cal-ISO shall be provided electronically to the CPM one day before synchronizing the facility with the California transmission system for the first time.	12/22/03		x		
VIS-1	CONS	The project owner shall ensure that visual impacts of project construction are adequately mitigated. To accomplish this, the project owner shall assure that: If visible from nearby residences and roadways including I-215, SR-74, Ethanac Road, Dawson Road, Almaden Lane, McLaughlin Road, Menifee Road, and Murrieta Boulevard, the project site as well as staging and material and equipment storage areas shall be visually screened with temporary screening fencing. Fencing will be of an appropriate design and color for each specific location. All evidence of construction activities, including ground disturbance due to staging and storage areas, shall be removed and all disturbed areas shall be remediated to an original or improved condition upon completion of construction including the replacement of any vegetation or paving removed during construction. The project owner shall submit to the CPM for review and approval a specific screening and restoration plan whose proper implementation will satisfy these requirements.	At least 60 days prior to the start of site mobilization, the project owner shall submit the screening and restoration plan to the CPM for review and approval and to Riverside County for review and comment. If the CPM notifies the project owner that any revisions of the screening and restoration plan are needed before the CPM will approve the plan, within 30 days of receiving that notification the project owner shall submit to the CPM a revised plan. The project owner shall notify the CPM within seven days after installing screening at staging and material and equipment storage areas that the screening is ready for inspection. The project owner shall notify the CPM within seven days after completing the surface restoration that the restoration is ready for inspection.	12/22/03		x		

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VIS-2	CONS	Prior to commercial operation, the project owner shall treat the surfaces of all project structures and buildings conventionally receiving color treatment and visible to the public such that: their colors minimize visual intrusion and contrast by blending with the landscape; their surfaces do not create glare; and they are consistent with local laws, ordinances, regulations, and standards. The project owner shall submit for CPM review and approval a specific treatment plan whose proper implementation will satisfy these requirements. The treatment plan shall include: a) Specification, and 11" x 17" color simulations at life size scale from KOPs 2, 4, and 5, of the treatment proposed for use on project structures, including structures treated during manufacture; b) A list of each major project structure, building, tank, transmission line tower and/or pole, and fencing specifying the color(s) and finish proposed for each (colors must be identified by name and by vendor brand or a universal designation); c) Two sets of brochures and/or color chips for each proposed color; d) Samples, approximately 8 inches by 10 inches, of each proposed treatment and color on each material to which they would be applied that would be visible to the public; e) A detailed schedule for completion of the treatment; and f) A procedure to ensure proper treatment maintenance for the life of the project. The project owner may, at its own risk, order equipment with factory surface treatment prior to approval of the treatment plan. If the CPM does not approve the treatment plan, the project owner shall have the equipment modified at its expense, as necessary, to obtain the required approval. Under no circumstances shall the project owner install the equipment at the project site prior to CPM approval of the treatment plan. The project owner shall not perform the final treatment on any buildings or structures until the project owner receives notification of approval of the treatment plan by the CPM.	The project owner shall submit its proposed treatment plan at least 60 days prior to ordering the first structures that are color treated during manufacture. If a revision is required, the project owner shall provide the CPM with a revised plan within 30 days of receiving notification that revisions are needed. Prior to the start of commercial operation, the project owner shall notify the CPM that all buildings and structures are ready for inspection. The project owner shall provide a status report regarding treatment maintenance in the Annual Compliance Report.	12/22/03		x		

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VIS-3	CONS	The project owner shall provide landscaping that is effective in screening the proposed project from views from I-215, State Route (SR)-74, Ethanac Road, Dawson Road, Almaden Lane, Spring Winds Drive, North Winds Drive, McLaughlin Road, Menifee Road, and nearby residences. Trees and other vegetation consisting of informal groupings of fast-growing evergreen species must be strategically placed and of sufficient density and height to effectively screen the majority of structural forms as soon as is reasonably practicable. The landscaping shall conform to Applicant's Revised Landscaping Plan submitted by the project owner on December 20, 2002 (Ex. 65) except for the changes indicated by italics in the following list: (1) street trees shall be planted immediately west of the project site along Antelope Road, (2) two offset rows of taller evergreen screening trees shall be planted on the berm to be constructed on the west side of the project site bordering Antelope Road, one row on top of the berm and one row on the west slope of the berm; (3) evergreen shrubs shall also be planted on the western berm to provide screening beneath the tree branches; (4) landscape plantings along the southern half of the western boundary shall be initiated within one year of the start of construction; (5) If the Riverside County Economic Development Agency agrees to permit the project owner to incorporate planting along the southern side of SR 74 into its plans for beautification of the SR 74 corridor, the plantings in this area shall be installed at the start of construction or as soon after the start of construction as the EDA permits; and (6) informal groupings of fast-growing broadleaf evergreen trees shall be placed along all sides of the compressor station site. The project owner shall submit a landscaping plan to the CPM for review and approval. The plan shall include: a) 11"x17" color simulations of the proposed landscaping at five years as viewed from KOPs 2, and 5; b) a plan view to scale depicting the project and the location of the landscape screening; c) a detailed list of plants to be used, their size, the expected time to maturity, and the expected height at five years and at maturity; and a table showing when the screening objectives are calculated to be achieved for each of the major project structures, and the height and elevation of the features of the existing setting and the project that are factors in those calculations; d) A description of any irrigation needed to ensure the proper growth and health of the plantings. The planting must be completed by start of commercial operation.	At least 45 days prior to installing the landscaping, the project owner shall submit the landscaping plan to the CPM for review and approval, and to Riverside County for review and comment. If the CPM notifies the project owner that revisions of the submittal are needed before the CPM will approve the submittal, within 30 days of receiving that notification the project owner shall prepare and submit to the CPM a revised submittal. The project owner shall notify the CPM, within seven days after completing installation of the landscaping, that the landscaping is ready for inspection.	06/22/05		x		
VIS-4	PC	The project owner shall ensure that lighting for construction of the power plant is used in a manner that minimizes potential night lighting impacts, as follows: a) All lighting shall be of minimum necessary brightness consistent with worker safety; b) All fixed position lighting shall be shielded, hooded, and directed downward to minimize backscatter to the night sky and direct light trespass (direct lighting extending outside the boundaries of the construction area); c) Wherever feasible and safe and not required for security, lighting shall be kept off when not in use and motion detectors shall be employed; and d) A lighting complaint resolution form (following the general format of that in the general compliance section of the compliance plan) shall be maintained by plant construction management to record all lighting complaints received and to document the resolution of each complaint.	Within seven days after the first use of construction lighting, the project owner shall notify the CPM that the lighting is ready for inspection. If the CPM notifies the project owner that modifications to the lighting are needed to minimize impacts, within 15 days of receiving that notification the project owner shall implement the necessary modifications and notify the CPM that the modifications have been completed. The project owner shall report any lighting complaints and documentation of resolution in the Monthly Compliance Report, accompanied by any lighting complaint resolution forms for that month.	12/22/03		x		

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VIS-5	OPS	The project owner shall design and install all permanent lighting such that light bulbs and reflectors are not visible from public viewing areas; lighting does not cause reflected glare; project illumination that is visible offsite is minimized; and illumination of the vicinity and the nighttime sky is minimized. To meet these requirements the project owner shall submit a lighting control plan that incorporates the following elements: a) Lighting shall be designed so exterior light fixtures are hooded, with lights directed downward or toward the area to be illuminated and so that backscatter to the nighttime sky is minimized. The design of the lighting shall be such that the luminescence or light source is shielded to prevent light trespass outside the project boundary. b) All lighting shall be of minimum necessary brightness consistent with worker safety and security; c) High illumination areas not occupied on a continuous basis (such as maintenance platforms) shall have switches or motion detectors to light the area only when occupied; and d) A lighting complaint resolution form (following the general format of that in the general section of the compliance plan) shall be used by plant operations to record all lighting complaints received and document the resolution of those complaints. All records of lighting complaints shall be kept in the on-site compliance file.	At least 60 days prior to ordering any permanent exterior lighting, the project owner shall contact the CPM to arrange a meeting to discuss the documentation required in the lighting control plan. At least 45 days prior to ordering any permanent exterior lighting, the project owner shall submit to the CPM for review and approval a lighting control plan that describes the measures to be used and demonstrates that the requirements of the condition will be satisfied. The project owner shall not order any exterior lighting until it receives CPM approval of the lighting control plan. Within 30 days after start of commercial operation, the project owner shall notify the CPM that the lighting has been completed and is ready for inspection. If the CPM notifies the project owner that modifications to the lighting are needed to satisfy the lighting requirements specified in this Condition, within 60 days of receiving that notification the project owner shall implement the modifications and notify the CPM that the modifications have been completed. The project owner shall report any complaints about permanent lighting and provide documentation of resolution in the Annual Compliance Report, accompanied by any lighting complaint resolution forms for that year.	12/22/03		x		
VIS-6	CONS	The project owner shall comply with the signage requirements of Riverside County. In addition, the project owner shall install minimal signage, which shall be constructed of non-glare materials and unobtrusive colors, except where otherwise required for safety. The design of any signs required by safety regulations shall conform to the criteria established by those regulations. The project owner shall submit a signage plan for the project to the CPM for review and approval and to Riverside County for review and comment. The project owner shall not implement the plan until the project owner receives approval of the submittal from the CPM.	At least 60 days prior to installing signage, the project owner shall submit the signage plan to the CPM for review and approval and to Riverside County for review and comment. If the CPM notifies the project owner that revisions of the plan are needed before the CPM will approve the submittal, within 30 days of receiving that notification the project owner shall prepare and submit to the CPM a revised submittal. The project owner shall notify the CPM within seven days after completing installation of signage that they are ready for inspection.	12/22/03		x		
VIS-7	PC	The project owner shall implement project design measures that minimize visual impacts associated with project operation. The project owner shall minimize project operational impacts by implementing the following: a) The project owner shall create a minimum 50-foot setback of project structures from surrounding roads (this requirement does not apply to transmission structures); b) The project owner shall place the one-story warehouse/ administration/ water treatment building, water tanks, and other smaller structures on the western edge of the project site to create a transition in scale between the corridor along Antelope Road and the plant's taller features; and c) The switchyard shall make use of low profile equipment, as depicted in the AFC on Figures 3.4-2 and 5.10-9b (Ex. 1, pp. 3-19, §5.10) to minimize its visibility beyond the tree rows that will be planted around it.	At least 60 days prior to the start of site mobilization, the project owner shall submit to the CPM for review and approval the specifications for (a) project setbacks, and (b) structural placement. At least 45 days prior to the start of construction on the switchyard, the project owner shall submit to the CPM, for review and approval, the specifications for switchyard equipment. If the CPM notifies the project owner that any revisions of the specifications are needed prior to CPM approval, within 30 days of receiving that notification the project owner shall submit to the CPM revised specifications.	12/22/03		x		

Condition No.	Sort Code	Description	Verification	COC Revision Date	Ongoing COC with Operations No Change Req'd for 7HA.01	Not Applicable for 7HA.01 Replacement	Applicable for 7HA.01 with Modification	Comment or Recommended Change
VIS-8	OPS	The project owner shall ensure that the IEEC cooling tower is designed and operated so that the plume frequency will not increase substantially from the design as certified. The project owner shall provide to the CPM for review and approval the final design specifications of the cooling tower related to plume formation. The project owner shall not order the cooling tower until notified by the CPM that the following design requirements have been satisfied: Either: a) The cooling tower design confirms that the exhaust air flow rate per heat rejection rate: will not be less than 28.4 kilograms per second per megawatt when ambient temperatures are between 32 degrees Fahrenheit and 100 degrees Fahrenheit; or b) If the cooling tower design exhaust air flow rates per heat rejection values are reduced from the levels shown above, the cooling tower design confirms that the plume frequency will not exceed staff's criteria for triggering a visual impact analysis (i.e., greater than 20 percent of the seasonal daylight clear hours).	If the project owner intends to comply under requirement (a) above, at least 30 days prior to ordering the cooling tower the project owner shall provide to the CPM for review and approval the final design specifications of the cooling tower related to plume formation. If the project owner intends to comply under requirement (b) above, at least 60 days prior to ordering the cooling tower the project owner shall provide to the CPM for review and approval the final design specifications of the cooling tower related to plume formation, including revised exhaust flow, exhaust temperature, and heat rejection data to allow staff to remodel the cooling tower plume frequency. The determination of percent of seasonal daylight clear hours will be based on a definition of "clear" as all hours with total sky cover equal to or less than 10 percent plus half of the hours with total sky cover 20-100 percent that have a sky opacity equal to or less than 50 percent. The project owner shall provide a written certification in each Annual Compliance Report to demonstrate that the cooling towers have consistently been operated within the design parameters, except as necessary to prevent damage to the cooling tower. If determined by the CPM to be necessary to ensure operational compliance, based on legitimate complaints received or physical evidence of potential non-compliant operation, the project owner shall monitor the cooling tower operating parameters in a manner and for a period as specified by the CPM. For each period that the cooling tower operation monitoring is required, the project owner shall provide to the CPM the cooling tower operating data within 30 days of the end of the monitoring period. The project owner shall include with this operating data an analysis of compliance and shall provide proposed remedial actions if compliance cannot be demonstrated.	06/22/05		x		
WASTE-1	PC	The project owner shall provide the resume of a Registered Professional Engineer or Geologist, who shall be available for consultation during soil excavation and grading activities, to the CPM for review and approval. The resume shall demonstrate experience in remedial investigation and feasibility studies. The Registered Professional Engineer or Geologist shall be given full authority to oversee any earth moving activities that have the potential to disturb contaminated soil.	At least 30 days prior to the start of site mobilization, the project owner shall submit the resume to the CPM.	12/22/03		x		
WASTE-2	CONS	If potentially contaminated soil is unearthed during excavation at either the proposed site or linear facilities as evidenced by discoloration, odor, detection by handheld instruments, or other signs, the Registered Professional Engineer or Geologist shall inspect the site, determine the need for sampling to confirm the nature and extent of contamination, and file a written report to the project owner and CPM stating the recommended course of action. Depending on the nature and extent of contamination, the Registered Professional Engineer or Geologist shall have the authority to temporarily suspend construction activity at that location for the protection of workers or the public. If, in the opinion of the Registered Professional Engineer or Geologist, significant remediation may be required, the project owner shall contact representatives of the Santa Ana Regional Water Quality Control Board, the Riverside County Department of Environmental Health, and the Cypress Regional Office of the California Department of Toxic Substances Control for guidance and possible oversight.	The project owner shall submit any reports filed by the Registered Professional Engineer or Geologist to the CPM within 5 days of their receipt. The project owner shall notify the CPM within 24 hours of any orders issued to halt construction.	12/22/03		x		
WASTE-3	CONS	The project owner shall obtain a hazardous waste generator identification number from the Department of Toxic Substances Control prior to generating any hazardous waste.	The project owner shall keep its copy of the identification number on file at the project site and notify the CPM via the Monthly Compliance Report of its receipt.	12/22/03	x			

Condition No.	Sort Code	Description	Verification	COC Revision Date	Ongoing COC with Operations No Change Req'd for 7HA.01	Not Applicable for 7HA.01 Replacement	Applicable for 7HA.01 with Modification	Comment or Recommended Change
WASTE-4	CONS	Upon becoming aware of any impending waste management related enforcement action by any local, state, or federal authority, the project owner shall notify the CPM of any such action taken or proposed to be taken against the project itself, or against any waste hauler or disposal facility or treatment operator with which the owner contracts.	The project owner shall notify the CPM in writing within 10 days of becoming aware of an impending enforcement action. The CPM shall notify the project owner of any changes that will be required in the manner in which project-related wastes are managed.	12/22/03	x			
WASTE-5	PC	The project owner shall prepare a Construction Waste Management Plan and an Operation Waste Management Plan for all wastes generated during construction and operation of the facility, respectively, and shall submit both plans to the CPM for review and approval, and to the Riverside County Department of Environmental Health and the Eastern Municipal Water District for review and comment. The plans shall contain, at a minimum, the following: • A description of all waste streams, including projections of frequency, amounts generated, and hazard classifications; and • Methods of managing each waste, including treatment methods and companies contracted with for treatment services, waste testing methods to assure correct classification, methods of transportation, disposal requirements and sites, and recycling and waste minimization/reduction plans.	No less than 30 days prior to the start of site mobilization, the project owner shall submit the Construction Waste Management Plan to the CPM for approval, and to the Riverside County Department of Environmental Health and the Eastern Municipal Water District for review and comment. The operation waste management plan shall be submitted to the CPM for approval, and to the Riverside County Department of Environmental Health and the Eastern Municipal Water District for review and comment no less than 30 days prior to the start of project operation. The project owner shall submit any required revisions within 20 days of notification by the CPM. In the Annual Compliance Reports, the project owner shall document the actual waste management methods used during the year compared to the planned management methods	12/22/03	x			
WORKER SAFETY-1	PC	The project owner shall submit to the CPM a copy of the Project Construction Safety and Health Program containing the following: 1. A Construction Injury and Illness Prevention Program 2. A Construction Fire Protection and Prevention Plan 3. A Personal Protective Equipment Program • The Construction Injury and Illness Prevention Program and the Personal Protective Equipment Program shall be submitted to the California Department of Industrial Relations, Division of Occupational Safety and Health (Cal/OSHA) Consultation • Service, if required, for review and comment concerning compliance of the program with all applicable Safety Orders. The Construction Fire Protection and Prevention Plan shall be submitted to the CPM for review and approval and to the Riverside County Fire Department and/or the Rural Fire Protection District for review and comment.	At least 30 days prior to the start of construction, the project owner shall submit to the CPM a copy of the Project Construction Safety and Health Program, the Personal Protective Equipment Program, and the Construction Fire Protection and Prevention Plan, including a copy of the cover letter transmitting the Programs to Cal/OSHA's Consultation Service, if required.	12/22/03		x		
WORKER SAFETY-2	CONS	The project owner shall submit to the CPM a copy of the Project Operation Safety and Health Program containing the following: 1. Operation Injury and Illness Prevention Program 2. Emergency Action Plan 3. Operation Fire Protection Program 4. Personal Protective Equipment Program • The Operation Injury and Illness Prevention Program, Emergency Action Plan, and Personal Protective Equipment Program shall be submitted to the California Department of Industrial Relations, Division of Occupational Safety and Health (Cal/OSHA) Consultation Service, if required, for review and comment concerning compliance of the program with all applicable Safety Orders. • The Operation Fire Protection Program and the Emergency Action Plan shall be submitted to the fire protection agency serving the project for review and comment.	At least 30 days prior to the start of operation, the project owner shall submit to the CPM a copy of the final version of the Project Operation Safety & Health Program. The document shall incorporate Cal/OSHA's Consultation Service comments, if any, regarding its review and acceptance of the specified elements of the proposed Operation Safety and Health Plan. The project owner shall notify the CPM that the Project Operation Safety and Health Program, including all records and files on accidents and incidents, are present on site.	12/22/03	x			

Condition No.	Sort Code	Description	Verification	COC Revision Date	Ongoing COC with Operations No Change Req'd for 7HA.01	Not Applicable for 7HA.01 Replacement	Applicable for 7HA.01 with Modification	Comment or Recommended Change
WORKER SAFETY-3	CONS	The Project Owner shall ensure that a CPM-approved Safety Monitor(s) conducts an on-site safety inspection of the power plant at least once a week during construction of permanent structures and commissioning unless a lesser number of inspections is approved by the CPM. The CPM may also require a similar inspection and report concerning linear facilities. The Safety Monitor shall keep the Chief Building Official (CBO) fully informed regarding safety-related matters and coordinate with the CBO concerning on-site safety inspections, and the final safety inspection prior to issuance of the Certificate of Occupancy by the CBO. The Safety Monitor will be retained until cessation of construction and commissioning activities, and issuance of the Certificate of Occupancy, unless otherwise approved by the CPM. The Safety Monitor(s) shall also: • Correct any construction or commissioning problems that could pose a future danger to life or health, consulting with the CBO as necessary. • Have the authority to temporarily stop construction or commissioning activities involving possible safety violations or unsafe conditions that may pose an immediate or future danger to life or health, until the problem is resolved to the satisfaction of the Safety Monitor and/or CBO. • Consult with the CBO to determine when construction may resume unless the problem is corrected immediately, and to the satisfaction of the Safety Monitor and/or CBO. • Inform the CPM within 24 hours of any temporary halt in construction or commissioning activities. • Be available to inspect the site whenever necessary in addition to the minimum weekly basis during construction and commissioning as determined in consultation with the CBO and CPM. • Develop a safety program for the Project that complies with Cal/OSHA & federal regulations related to power plant projects. • Ensure that all federal and Cal/OSHA requirements are practiced during the construction and installation of all permanent structures (including safety aspects of electrical installations). • Ensure that all construction and commissioning workers and supervisors receive adequate safety training. • Conduct safety training (including fall protection, confined spaces, respiratory protection, hazard communication, etc.), or ensure that the Project owner, union hall, and/or contractors conduct adequate safety training.	Verification: The Project owner shall submit the Safety Monitor(s) resume(s) to the CPM for approval at least 30 days prior to site mobilization. One or more individuals may hold this position. The Safety Monitor shall submit in the Monthly Compliance Report a monthly safety inspection report to include: • Records of all employees trained for that month (all records shall be kept on site for the duration of the Project); • A summary report of safety management actions that occurred +D230during the month; • A report of any continuing or unresolved situations and incidents that may pose danger to life or health; • Reports of OSHA Recordable and Lost Time incidents and injuries that occurred during the month.	06/20/05		x		

Condition No.	Sort Code	Description	Verification	COC Revision Date	Ongoing COC with Operations No Change Req'd for 7HA.01	Not Applicable for 7HA.01 Replacement	Applicable for 7HA.01 with Modification	Comment or Recommended Change

References:

CEC (California Energy Commission), December 22, 2003. Commission Final Decision of the Inland Empire Energy Center Project (01-AFC-17).

CEC (California Energy Commission), June 20, 2005. Inland Empire Energy Center Project (01-AFC-17C). Commission Staff's Errata and Amendments to Staff Analysis and Responses to Project Owner's Comments.

CEC (California Energy Commission), June 22, 2005. Order Approving a Petition to Change to GE 107H Combined-Cycle Systems and add secondary laydown/parking areas (01-AFC-17C).

CEC (California Energy Commission), November 3, 2005. Order No. 05-1103-03. Inland Empire Energy Center Project (01-AFC-17C). Order Approving a Petition to change Ownership of the Transmission Line and Two TLSN Conditions of Certification.

CEC (California Energy Commission), April 11, 2007. Order Approving a Petition to Modify Various Air Quality Conditions of Certification (01-AFC-17C).

CEC (California Energy Commission), December 15, 2010. Order No. 10-1215-17. Order Approving a Petition to Modify Air Quality Conditions of Certification. Docket # 59311.

CEC (California Energy Commission), June 27, 2012. Inland Empire Energy Center Project (01-AFC-17C). Annual Greenhouse Gas Emissions Reporting Requirements Pursuant to Condition of Certification AQ-SC17. Docket # 65983.

APPENDIX F
U.S. EPA PSD APPLICABILITY ANALYSIS

GE
Energy

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September 30, 2014

Ref. No. GE/IEEC – 0862

Mr. Gerardo Rios
Permits Chief
U.S. Environmental Protection Agency, Region 9
Air Division, AIR-3
75 Hawthorne Street
San Francisco, CA 94105-3901

Subject: Inland Empire Energy Center Unit 2 Combustion Turbine Replacement Project PSD Review Applicability Analysis

Dear Mr. Rios:

Inland Empire Energy Center, LLC (IEEC) currently owns and operates two power-generating units and ancillary equipment that serve the growing demand for power in California's greater Inland Empire region. The IEEC facility is a major emitting facility that operates under a Permit to Operate/Title V permit issued and administered by the South Coast Air Quality Management District (SCAQMD). The existing facility is major for the following attainment new source review (NSR) pollutants: nitrogen dioxide (NO_2), carbon monoxide (CO) and particulate matter less than 10 microns (PM_{10}). The facility's emissions of sulfur dioxide (SO_2) (and therefore also sulfuric acid mist) are minor; ozone and particulate matter less than 2.5 microns are both nonattainment pollutants.

As you are aware from our August 7, 2014, meeting in San Francisco, IEEC LLC proposes to replace one of the facility's two existing GE Frame 7H combustion turbines (CTs) with the latest generation in H technology to better serve demand growth. The 7H technology has continued to evolve, and the new 7HA.01 unit would provide the following benefits:

- Improved efficiency;
- Lower operation and maintenance costs; and
- Reduced water usage from an air-cooled gas turbine.

The following analysis of Prevention of Significant Deterioration (PSD) applicability is provided to U.S. Environmental Protection Agency (U.S. EPA) Region 9 per 40 Code of Federal Regulations (CFR) 52.21(r)(6)(ii).[1] IEEC LLC is not seeking, nor is it required to seek, any determination from

[1] 40 CFR 52.21(r)(6)(ii) requires IEEC to provide U.S. EPA with a copy of the information set out in 40 CFR 52.21(r)(6)(i), which consists of: (a) a description of the project; (b) identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and (c) a description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under 40 CFR 52.21(b)(41)(ii)(c) and an explanation for why such amount was excluded, and any netting calculations, if applicable.

U.S. EPA.[2] The analysis demonstrates that the proposed Unit 2 turbine replacement project is a minor modification, and that PSD review is not required.

Equipment

The proposed 7HA.01 CT replacement unit will be a functionally equivalent model to the existing Unit 2 7H CT from flange to flange. The existing plant layout and balance of plant equipment, including stacks, heat recovery steam generator and associated emission control systems, and steam turbine generator, will remain unchanged. Similarly, the existing auxiliary boiler, wet cooling tower system (total 16 cells), a diesel firewater pump, and two diesel emergency generators will remain unchanged.

Historic and Future Operations

Inland Empire Energy Center currently operates in the day-ahead merchant market in California Independent System Operator. IEEC considered historical operations and the future market for electrical generation at IEEC in developing future operating scenarios. Estimating future operations of the facility depends on many factors, including the projected demand for generation (which, in turn, is driven by a range of factors, such as assumed future economic activity and success of energy efficiency programs), operating costs, price of electricity, and policy assumptions. The U.S. Energy Information Administration has determined that there will be substantial uncertainty in projecting demand for future generation because many of the events that shape energy markets are not fully predictable, and because future developments in technologies, demographics, and resources cannot be foreseen with certainty.[3] In addition to broader uncertainties regarding future demand for generation, a number of local and regional factors may impact the demand for future generation at IEEC, including the shutdown of the San Onofre Nuclear Generating Station, retirement of once-through cooling power plants, and ongoing growth of and need to integrate variable renewable generation.

To address the market uncertainty and quantify projected actual emissions (PAE), IEEC LLC considered two scenarios. One future scenario represents maximum base-load operation with corresponding startups and shutdowns and planned maintenance outages. The second scenario represents a reasonable maximum cycling scenario, with IEEC providing intermediate cycling capacity and energy and renewables integration support to the grid. As shown in Table 1, the project does not trigger PSD review for any attainment pollutant under either scenario. Unused capacity emission calculations and assumptions for the baseline period are provided in Table 2.

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2 "Nothing in this paragraph (r)(6)(ii) shall be construed to require the owner or operator of such a unit to obtain any determination from the Administrator before beginning actual construction." 40 CFR 52.21(r)(6)(ii).

3 U.S. Energy Information Administration, Annual Energy Outlook 2014 with Projections to 2040, at iii (April 2014) (available online at: http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf). ("Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty.")

PSD Applicability Analysis

PSD review is applicable only to *major modifications at major stationary sources* per 40 CFR Section 52.21, Paragraph (a)(2). Subsequent rule paragraph citations below are also in reference to Section 52.21 (Rule). The following analysis applies the *actual to projected-actual* applicability test for existing emission units under Rule Paragraph (a)(2)(iv)(c) to assess whether the proposed project would cause significant emissions increases for attainment NSR pollutants. Therefore, the difference between the PAE (as defined in Rule Paragraph [b][41]) and the *baseline actual emissions* (BAEs) (as defined in Rule Paragraph [b][48][i] for existing *electric utility steam generating units*) is compared to *significant amounts* for each NSR pollutant in Rule Paragraph (b)(23). Note that IEEC Units 1 and 2 both qualify as *electric utility steam generating units* under Rule Paragraph (b)(31).

Rule Paragraph (b)(41)(ii)(c) allows that facility emissions associated with previously unused permitted generating capacity that could have been accommodated by the existing unit (and that are unrelated to the modification) may be subtracted from the PAE. More specifically, the pertinent regulatory language provides:

"In determining the projected actual emissions ..., the owner or operator of the major stationary source:

...(c) Shall exclude, in calculating any increase in emissions that results from [t]he particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(48) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth;"

Accordingly, the following emissions have been calculated for Unit 2 before and after the turbine replacement project:

- BAE, based on any consecutive 24-month period in the last 5 years (Rule Paragraph [b][48][i]);

- PAE after the project, based on the maximum annual emissions that IEEC anticipates may occur during the 5 years after project implementation (Rule Paragraph [b][41][i]); and

- Unused capacity emissions, based on the capacity that the unit could have operated at—if there had been sufficient market demand in the same period that was used for the BAE (Rule Paragraph [b][41][ii][c]).

BAE and PAE estimates, and underlying assumptions, are provided and summarized in Table 1 for each attainment NSR pollutant. Table 1 also compares resulting net emissions increases with applicable PSD significance levels for each pollutant. BAE values are based on 24 months of facility emission data during the past 5 years. Actual emissions from the most recent 5-year period, 2010-2014, were used in this analysis. Emissions over each consecutive 24-month period were averaged, and the highest annual average emission rate for each pollutant was selected as BAE. Rule Paragraph (b)(48)(i)(c) allows use of different baseline years for each pollutant. Additionally, it should be noted that in this time frame the facility did not have any period of emissions greater than any legally enforceable limitations; therefore, noncompliant emissions were not subtracted, per Rule Paragraph (b)(48)(i)(b).

PAE estimates are provided for the two scenarios discussed above that bracket the anticipated range of future facility operations after project implementation. One future scenario represents maximum base-load operation with corresponding startups and shutdowns. The second scenario represents a reasonable maximum cycling scenario, with IEEC providing intermediate cycling capacity and energy and renewables integration support to the grid. Unused capacity emission calculations and assumptions for the baseline period are provided in Table 2. The calculated unused capacity emissions are not related to the proposed CT replacement; this capacity factor could have been achieved by the existing Unit 2 7H CT if historic demand for baseload generation had been higher. A Frame 7HA.01 CT is functionally equivalent to the existing 7H unit, and the project will not increase Unit 2's generating capacity.

For simplicity, the facility's particulate matter emissions conservatively are assumed to be entirely PM_{10} for this analysis.

Summary of Results

Net emission increase estimates in Table 1 demonstrate that the proposed project will not result in significant increases for the attainment NSR pollutants NO_2, CO, PM_{10} and SO_2 under either potential operating scenario. As a result of the U.S. Supreme Court ruling in Utility Air Regulatory Group v. EPA,[4] the Project is not subject to PSD review for greenhouse gases under the federal regulations or SCAQMD Rule 1714, because the turbine replacement's criteria pollutant emissions do not exceed the significance levels set forth in Rule Paragraph (b)(23).

In sum, PSD review is not required for the proposed combustion turbine replacement project.

Thank you for considering this analysis. Please contact me at (951) 928-5907 or alisa.moretto@ge.com if you have any questions or require additional information.

Sincerely,

Alisa Moretto

Alisa Moretto
Technical Compliance Manager
Inland Empire Energy Center, LLC

Attachments: Table 1
Table 2

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[4] 134 S. Ct. 2427, 573 U.S. ____ (2014) (Docket No. 12-1146).

TABLE 1
PSD Comparison - Actual to Projected Actual Emissions test

Pollutant	Projected actual emissions (PAE)[a] Baseload (tpy)	Projected actual emissions (PAE)[a] Cycling (tpy)	Unused capacity emissions[b] (tpy)	Baseline actual emissions (BAE)[c] (tpy)	Net increase Baseload (tpy)	Net increase Cycling (tpy)	PSD Significant Emission Rate	PSD Trigger?
NO_x	79.1	59.9	21.9	24.8	32.4	13.2	*40*	N
PM_{10}	30.6	18.7	12.8	14.9	2.9	-9.0	*10*	N
CO	48.9	53.8	7.5	3.6	37.8	42.6	*100*	N
SO_2	7.5	4.5	3.1	3.6	0.7	-2.3	*40*	N

a. Basis for Post-Project Projected Actual Emissions (PAE)

1. These projections are based on emission estimates for the 7HA.01 turbine, and the following operating scenarios:

	Annual baseload scenario	Annual cycling scenario
Cold Start (#/year)	12	48
Warm Start (#/year)	12	0
Hot Start (#/year)	0	240
Shutdown (#/year)	24	288
Steady State (hours/year)	8141	4800

2. The basis for the baseload and cycling scenarios is provided in the text of this submittal.
3. All assumptions are subject to change as a result of actual market conditions, equipment performance and power sales opportunities.

b. Basis for Unused Capacity Emissions

1. Actual operations during the baseline analysis period (2010-2014) were limited by market conditions (low demand).
2. Baseline Actual Emissions are factored up from actual baseline capacity to the potential capacity factor of Unit 2 (capacity factor that Unit 2 could have accomodated) during the same period.
3. Detailed calculations are shown in Table 2.

c. Basis for Baseline Actual Emissions (BAE)

1. Baseline emissions are based on the highest consecutive two-year period over the last five years.

Baseline Actual Emissions		Quarterly Emissions				Annual average, 24-month rolling			
	Natural Gas Unit 2	NOx	PM_{10}	CO	SO_2	NOx	PM_{10}	CO	SO_2
Period	(mmscf)	(lbs)	(lbs)	(lbs)	(lbs)	(tpy)	(tpy)	(tpy)	(tpy)
2010 Q3	3,049	15,995	8,934		2,165				
2010 Q4	3,569	21,245	10,457	2,004	2,534				
2011 Q1	3,286	17,352	9,629		2,333				
2011 Q2	7	821	20	1,302	5				
2011 Q3	2,678	13,226	7,845		1,901				
2011 Q4	2,572	12,475	7,536	2,310	1,826				
2012 Q1	4,043	16,003	11,845		2,870				
2012 Q2	356	2,056	1,042	2,117	253	24.8	14.3	1.9	3.5
2012 Q3	3,824	14,308	11,206		2,715	24.4	14.9		3.6
2012 Q4	2,133	9,340	6,251	1,438	1,515	21.4	13.8	1.8	3.4
2013 Q1	1,451	7,000	4,252		1,030	18.8	12.5		3.0
2013 Q2	846	4,016	2,480	5,663	601	19.6	13.1	2.9	3.2
2013 Q3	2,874	15,446	8,421		2,041	20.2	13.3		3.2
2013 Q4	519	3,647	1,521	2,664	369	18.0	11.8	3.0	2.8
2014 Q1	1,074	6,333	3,148		763	15.5	9.6		2.3
2014 Q2	196	1,878	574	4,692	139	15.5	9.5	3.6	2.3

Notes:

1. Natural gas usage data from CEMS meter readings.
2. NOx data from Annual Permit Emissions Program (APEP) reporting.
3. CO data from Data Acquisition System (DAS); only available for six month periods, not quarterly.
4. PM_{10} and SO_2 emissions calculated based on natural gas usage, using permitted emission factors.
5. Unit 2 commissioning was completed in the second quarter of 2010; thus normal operations started in the third quarter, and only four years of historical data are available.

CYCLING SCENARIO

Turbine Operation	January	Feb	March	April	May	June
Cold starts	4	4	4	4	4	4
Warm starts	0	0	0	0	0	0
Hot starts	20	20	20	20	20	20
Shutdowns	24	24	24	24	24	24
Steady-state	400	400	400	400	400	400

CYCLING SCENARIO

Turbine Operation	July	Aug	Sept	Oct	Nov	Dec	**TOTAL**
Cold starts	4	4	4	4	4	4	**48**
Warm starts	0	0	0	0	0	0	**0**
Hot starts	20	20	20	20	20	20	**240**
Shutdowns	24	24	24	24	24	24	**288**
Steady-state	400	400	400	400	400	400	**4800**

Operating Scenarios	**Baseload Scenario**	**Cycling Scenario**
Startups	1 cold and 1 warm startup per month, all 12 months	Cold start every Monday, warm start every weekday, and shutdown over the weekend.
Steady-State	Annually 8,760 hours minus 25 days of maintenance outage minus startup/shutdown time	Weekday operations only, assuming 20 hours per day, 20 days per month.

TABLE 2
DERIVATION OF UNUSED CAPACITY EMISSIONS FROM PRE-PROJECT BASELINE ACTUAL EMISSIONS (BAE) AND BASELINE CAPACITY FACTORS

	Unit 2			
	NO_X	PM_{10}	CO	SO_X
Baseline Period	2010 Q3 - 2012 Q2	2010 Q4 - 2012 Q3	2012 Q3 - 2014 Q2	2010 Q4 - 2012 Q3
Baseline Actual Emissions (ton)	24.79	14.90	3.61	3.61
Baseline Actual Capacity Factor	47%	48%	30%	48%
Potential Capacity Factor during Baseline Period	88%	90%	92%	90%
Emissions @ Full Capacity (ton)	46.67	27.70	11.12	6.71
Unused Capacity Emissions (ton)	21.88	12.81	7.50	3.10

Notes and Assumptions:

1. Actual operations during the baseline analysis period (2010-2014) were limited by market conditions (low demand).
2. Actual Capacity Factor is how much the unit actually ran in that period.
3. Potential Capacity Factor is the capacity that the Unit 2 turbine could have operated at if there had been sufficient market demand.
4. Emissions at Capacity are based on Baseline Actual Emissions factored up from actual baseline capacity to the Potential Capacity Factor in the same time period.
5. Excluded emissions = Emissions at Capacity - Actual Emissions

ANNUAL GENERATION AND CAPACITY FACTORS DURING BASELINE ANALYSIS PERIOD

	Actual Capacity Factor	Potential Capacity Factor
Baseline Emissions Period	**Unit 2**	**Unit 2**
2010 Q3 - 2012 Q2 (NOx)	47%	88%
2010 Q4 - 2012 Q3 (PM_{10} and SOx)	48%	90%
2012 Q3 - 2014 Q2 (CO)	30%	92%

Source: IEEC data.