Inland Empire Energy Center

(01-AFC-17)

Amendment No. 1

(GE H Technology and Additional Laydown Area)

Submitted by

Inland Empire Energy Center, LLC

March 2005

With Technical Assistance by

CH2MHILL

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Acronyms and Abbreviations

AFC	Application for Certification
APE	Area of Potential Effect
APN	Assessor's Parcel Number
BA	Biological Assessment
BACT	Best Available Control Technology
BMP	Best management practices
BOP	Balance of plant
Btu	British thermal unit
BRMIMP	Biological Resources Mitigation Implementation and Monitoring Plan
CAISO	California Independent System Operator
CalARP	California Accidental Release Program
CARB	California Air Resources Board
CATEF	California Air Toxic Emission Factor
CCR	California Code of Regulations
CDFG	California Department of Fish and Game
CEC	California Energy Commission
CEDD	California Employment Development Department
CNDDB	California Natural Diversity Data Base
CO	Carbon monoxide
Commission Decision	December 31, 2003 California Energy Commission Decision regarding the IEEC's license
CNEL	Community Noise Equivalent Level
CNPS	California Native Plant Society
CSC	California Species of Special Concern
CT	Combustion turbine
CTG	Combustion turbine generator

dBA	decibel (A-weighted)
DLN	Dry low-NOx
DOF	Department of Finance
DP	Design points
EDI	Electro-deionization
EMWD	Eastern Municipal Water District
EPA	Environmental Protection Agency
ERC	Emission reduction credit
FDOC	Final Determination of Compliance
FLM	Federal Land Manager
GE	General Electric Company
gpm	Gallons per minute
HARP	Hotspots Analysis and Reporting Program
HCP	Habitat Conservation Plan
HHV	Higher heating value
HP	High pressure
HRA	Health risk assessment
HRSG	Heat recovery steam generator
IEEC	Inland Empire Energy Center
IP	Intermediate pressure
LHV	Lower heating value
LLC	Limited Liability Corporation
LOS	Level of Service
LP	Low pressure
LORS	Laws, Ordinances, Regulations, and Standards
MW	Megawatt
MWD	Metropolitan Water District
MSA	Metropolitan Statistical Area
MSDS	Material Safety Data Sheet
MSHCP	Multi-Species Habitat Conservation Plan

NOx	Oxides of nitrogen
NPDES	National Pollution Discharge Elimination System
OEHHA	Office of Environmental Health and Hazard Assessment
PAH	Polycyclic aromatic hydrocarbons
PDC	Power Distribution Center
PM_{10}	Particulate matter less than 10 microns
PSD	Prevention of Significant Deterioration
RTC	RECLAIM Trading Credits
RSBTC	Riverside-San Bernardino Building Trades Council
RWRF	Regional Water Reclamation Facility
SAA	Streambed Alteration Agreement
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SCR	Selective Catalytic Reduction
SIS	System Impact Study
SKR	Stephens' kangaroo rat
SRWQCB	State Regional Water Quality Control Board
ST	Steam turbine
STG	Steam turbine generator
SWPPP	Storm Water Pollution Prevention Plan
TDS	Total dissolved solids
tpy	Tons per year
UAT	Unit Auxiliary Transformers
UPS	Uninterruptible power supply
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
UV	Ultraviolet
VOC	Volatile organic compounds

Executive Summary

The Inland Empire Energy Center, LLC, as project owner, petitions the California Energy Commission (CEC or Commission) to amend the certification for the Inland Empire Energy Center (IEEC) (01-AFC-17, issued December 22, 2003). This Amendment has two components: (1) a request to change the power generation configuration (from the previously proposed two GE Energy 7FB combustion turbine generators (CTGs) and one steam turbine generator [STG]) to a new configuration using two GE S107H Systems, and (2) a request to add an additional temporary area near the project site for construction worker parking and secondary laydown.

This project is an opportunity to build the most advanced gas-fired, combined-cycle technology available, at a site in California that has already been certified as an appropriate location for an electric generating facility. The H Systems are the most efficient gas turbine, combined-cycle design available to the power industry, providing superior fuel economy and environmental performance. Fuel efficiency translates into lower cost of producing electricity and lower emissions per unit of electricity.

Section 1 provides an overview of the Amendment and a review of the ownership of the project, the necessity for the proposed change, and the consistency of the changes with the Commission Decision certifying the facility. Section 2 provides a complete description of the proposed modifications, including updated drawings. Section 3 assesses the potential environmental effects of the proposed changes in terms of 14 environmental discipline areas. This Assessment indicates that adoption of the Amendment will not result in any significant, unmitigated adverse environmental impacts. Similarly, the project as amended will continue to comply with all applicable laws, ordinances, regulations and standards. The findings and conclusions contained in the December 22, 2003 Commission Decision granting certification of the IEEC are still applicable to the project, as amended. A few of the Conditions of Certification in the Commission Decision require minor revisions to reflect the proposed project changes. For the sections affected, a proposed markup of the Conditions of Certification is included.

The project owner is prepared to begin construction as soon as all regulatory approvals are complete. The petitioners have requested and funded expedited treatment of the air permitting review by South Coast Air Quality Management District. Similarly, because the project owner proposes to construct an energy center with superior environmental performance at an already certified site, timely review of this Amendment by the Commission is requested.

Unlike many merchant power plants in the California market, this project has the financing to begin construction as soon as the regulatory approvals are complete. Construction is planned to begin in July of 2005 in order to meet the summer loads of Southern California in 2008.

1.0 Introduction

1.1 Overview of Amendment

The Inland Empire Energy Center, LLC (the "Project Owner") hereby petitions to amend the certification for the Inland Empire Energy Center (IEEC) (01-AFC-17). This Amendment request has two components: (1) change the power generation configuration from the previously proposed two GE Energy 7FB combustion turbine generators (CTGs) and one steam turbine generator (STG) to a new configuration using two GE S107H Systems. 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 includes the most advanced commercially available gas turbine currently produced by GE Energy.

This Amendment contains all of the information that is required pursuant to CEC's Siting Regulations (California Code of Regulations [CCR] Title 20, Section 1769, Post Certification Amendments and Changes). The information necessary to fulfill the requirements of Section 1769 is contained in Sections 1.0 through 6.0 as summarized in Table 1-1 below.

TABLE 1-1.
Informational Requirements for Post-Certification Amendments and Changes

Section 1769 Requirement	Section of Petition Fulfilling Requirement
(A) A complete description of the proposed modifications, including new language for any conditions that will be affected	Section 2.0—Proposed modifications Sections 3.1 to 3.15—Proposed changes to conditions of certification, where necessary, are located at the end of each technical section
(B) A discussion of the necessity for the proposed modifications	Section 1.3
(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	Section 1.3
(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	Sections 1.4, 3.1 to 3.16
(E) An analysis of the impacts the modification may have on the environment and proposed measures to mitigate any significant adverse impacts	Section 3.1 to 3.15
(F) A discussion of the impact of the modification on the facility's ability to comply with applicable laws, ordinances, regulations, and standards;	Section 3.1 to 3.16
(G) A discussion of how the modification affects the public	Section 4.0
(H) A list of property owners potentially affected by the	Section 5.0

TABLE 1-1.
Informational Requirements for Post-Certification Amendments and Changes

Section 1769 Requirement	Section of Petition Fulfilling Requirement
modification	
(I) A discussion of the potential effect on nearby property owners, the public and the parties in the application proceedings.	Section 6.0

1.2 Ownership of Inland Empire Energy Center, LLC

Inland Empire Energy Center (IEEC), LLC, a wholly owned subsidiary of Calpine Corporation, is the project owner. On November 15, 2005, Calpine Corporation and GE Energy entered into a Letter of Intent agreement that provides for GE Energy to acquire IEEC, LLC after the project, as amended, has received certain regulatory approvals. The terms of the transfer of ownership have not been finalized as of the filing of this Amendment and the date of change of project company ownership is not known at this time. GE Energy and Calpine will apply for a change in ownership at the appropriate time.

This is a long-term relationship between the two companies which requires Calpine to obtain the necessary approvals for the new GE S107H System, provide ongoing support in compliance and community relations during construction and ultimately become the owner of the plant. Given this long term relationship, Calpine will approach the pre-construction compliance process in much the same way as if it were the owner, similar to its other California projects.

1.3 Necessity of Proposed Changes

The Siting Regulations require a discussion of the necessity for the proposed revision to the IEEC project and whether the modification is based on information known by the petitioner during the certification proceeding (Title 20, CCR, Sections 1769 [a][1][B], and [C]). This Amendment will allow the project to take advantage of the most recent developments in gas turbine technology. The H System is the most efficient, gas-turbine combined-cycle design available to the power industry. For every unit of electricity produced, the GE S107H System uses less fuel and produces lower levels of greenhouse gas and other emissions when compared to other large gas turbine combined-cycle systems.

The proposed addition of approximately 9.6 acres of construction worker parking and secondary laydown area adjacent to the project parcel will allow for a more efficient use of the project site during construction and safer and more cost-effective construction staging. These proposed changes are based on information that became known to the petitioner after the project was certified.

1.4 Consistency of Changes With Certification

The Siting Regulations also require a discussion of the consistency of the proposed project revision with the applicable laws, ordinances, regulations, and standards (LORS) and whether the modifications are based upon new information that changes or undermines the assumptions, rationale, findings, or other bases of the final decision (Title 14, CCR Section 1769 [a][1][D]). If the project is no longer consistent with the certification, the Amendment must provide an explanation for why the modification should be permitted.

The proposed project revisions are consistent with all applicable LORS. This Amendment is not based upon new information that changes or undermines any bases for the final decision. The findings and conclusions contained in the Commission Decision for the IEEC project (California Energy Commission 2003) are still applicable to the project as modified.

1.5 Summary of Environmental Impacts

The CEC Siting Regulations require that an analysis be conducted to address the potential impacts the proposed Amendment may have on the environment and proposed measures to mitigate any potentially significant adverse impacts (Title 20, CCR, Section 1769 [a][1][E]). The regulations also require a discussion of the impact of the proposed Amendment on the facility's ability to comply with applicable LORS (Section 1769 [1][a][F]). Section 3.0 of this Amendment includes a discussion of the potential environmental impacts associated with the Amendment as well as a discussion of the consistency of the modification with LORS. For discipline areas affected by the proposed modifications, Section 3.0 also includes any information necessary to update environmental baseline information to reflect significant changes in baseline conditions that may have occurred between the time information submitted previously in support of the application was developed and the present. Section 3 concludes that there would be no significant environmental impacts associated with implementing the actions specified in the Amendment and that the project as modified would comply with all applicable LORS.

1.6 References Cited

California Energy Commission. 2003. Commission Decision, Inland Empire Energy Center, Application for Certification (01-AFC-17), Riverside County. California Energy Commission, Sacramento, California. December 22, 2003.

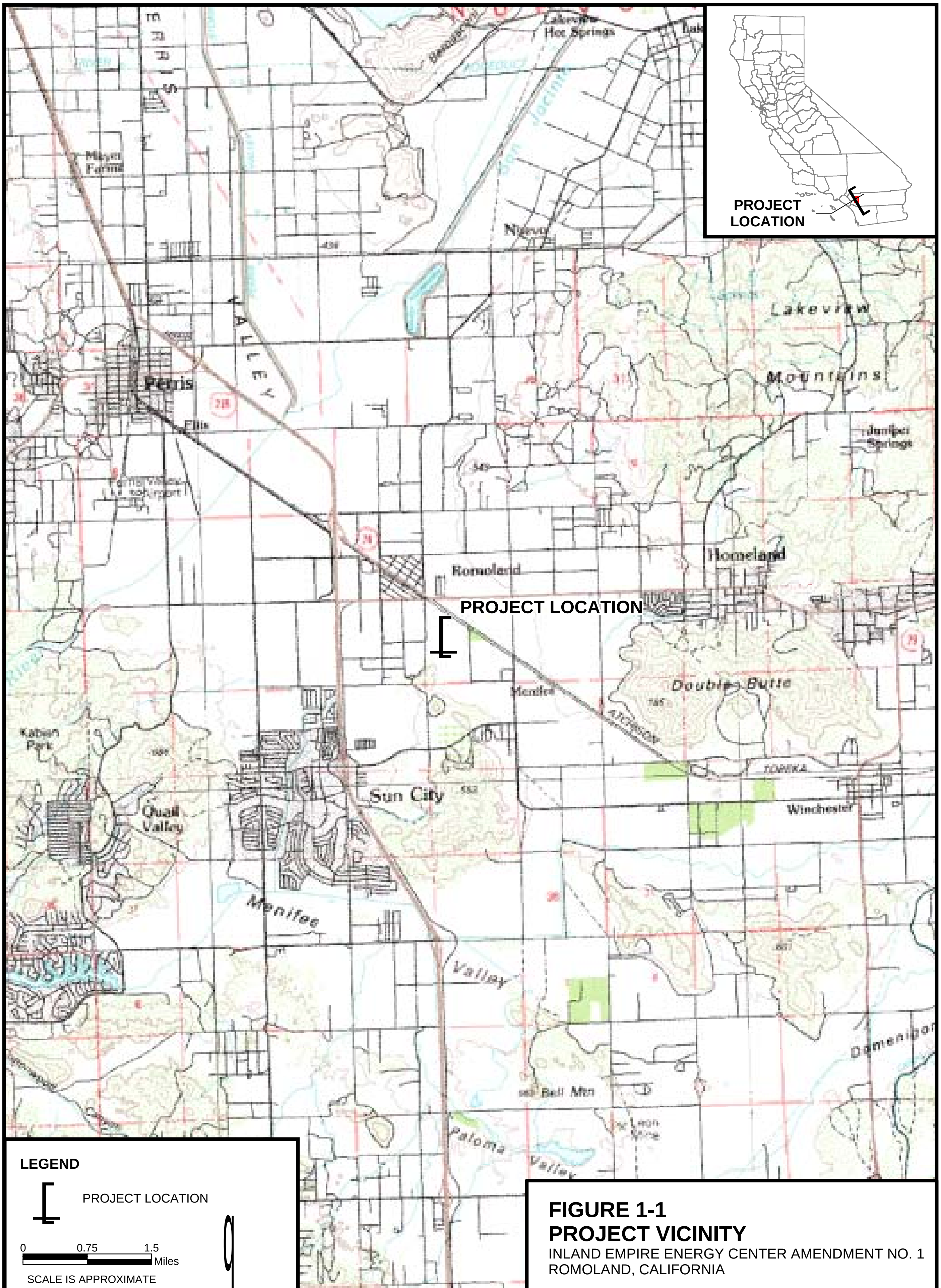


FIGURE 1-1
PROJECT VICINITY
INLAND EMPIRE ENERGY CENTER AMENDMENT NO. 1
ROMOLAND, CALIFORNIA

CH2MHILL

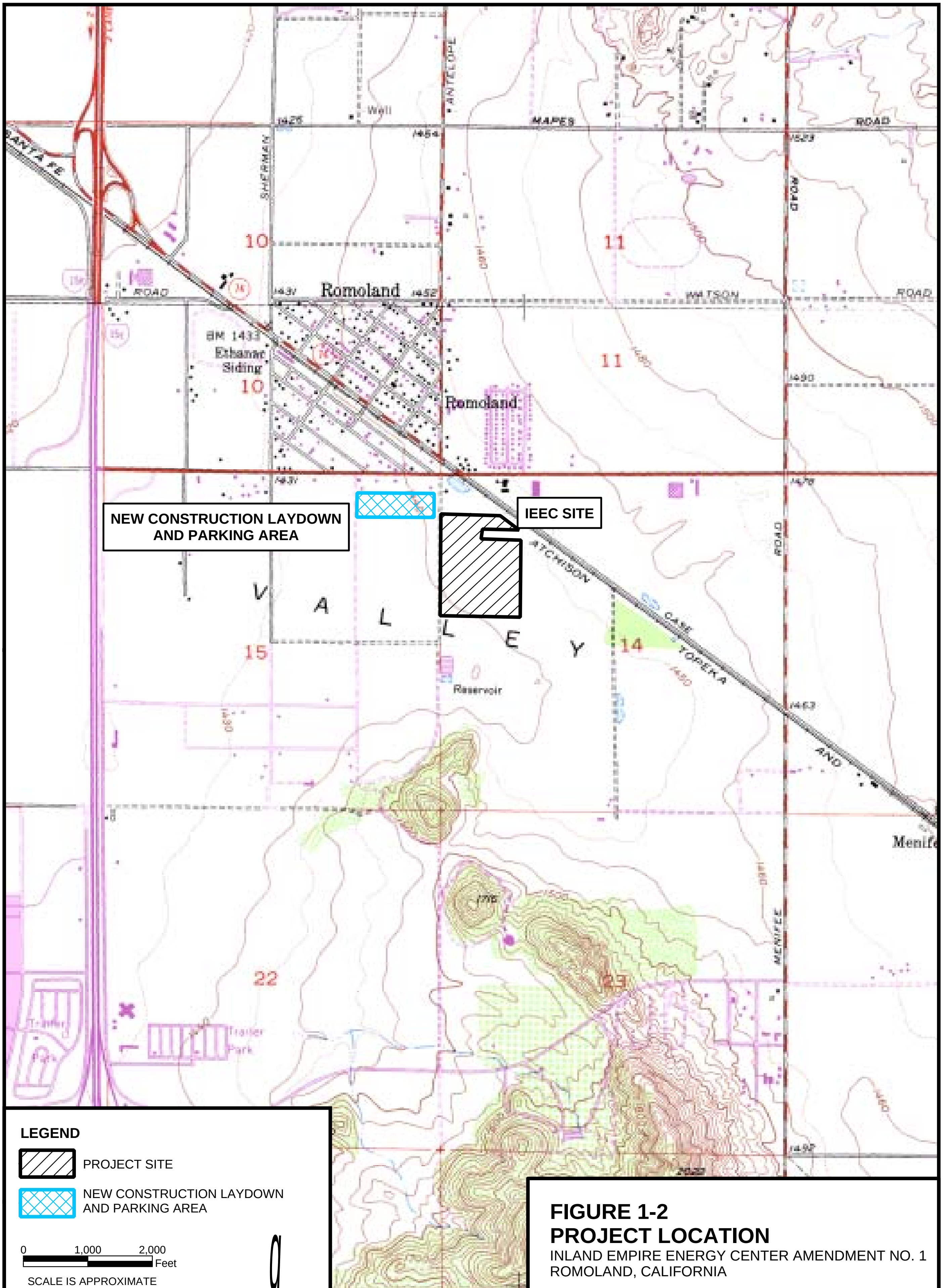


FIGURE 1-2
PROJECT LOCATION
INLAND EMPIRE ENERGY CENTER AMENDMENT NO. 1
ROMOLAND, CALIFORNIA

CH2MHILL

2.0 Description of Project Amendment

This section includes a complete description of the proposed project Amendment consistent with CEC Siting Regulations (Title 20, CCR, Section 1769 [a][1][A]).

2.1 Energy Center

2.1.1 Energy Center Site Arrangement

The proposed change in the power generation configuration will require a revised site arrangement as shown in Figure 2-1. Including access roads and landscaping, the energy center will still occupy approximately 35 acres of the 45.8-acre project site. The energy center fenced area has been increased from 24 acres to approximately 28 acres. Figures 2-2 and 2-3 show north, south, east, and west elevations. Key revisions to the site layout are as follows:

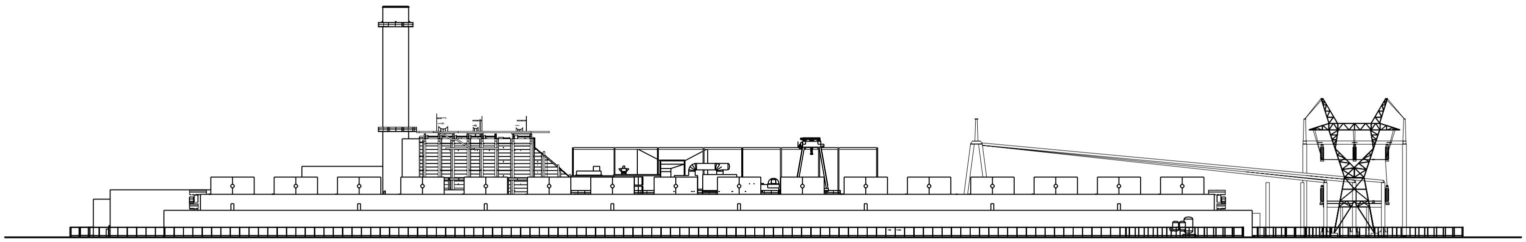
- The entire facility has been moved approximately 80 feet to the south.
- There are now two steam turbines (ST) instead of one. Each steam turbine will be share a common shaft line and generator with its corresponding combustion turbine (CT).
- Because the CTs and steam turbines STs share common shaft lines, the entire line-ups are pedestal mounted at the ST elevation with the condensers located directly below the STs. The CTs are thus higher in relation to ground level in the revised design.
- The CT air inlet filters are located on the north, instead of the east, side of the units.
- Each CT/ST/generator line-up will have a permanently installed bridge/gantry crane to facilitate maintenance activities.
- The spacing between the centerlines of the two CT/ST/heat recovery steam generators (HRSG) trains has been increased to allow sufficient space around the units for the associated auxiliary and common equipment.
- The HRSG stacks have been separated so that they may be located adjacent to the corresponding HRSGs.
- Each ST will have a dedicated cooling tower; including their pump pits, circulating water pumps, and circulating water piping. The new design features two 8-cell cooling towers (compared with 14 cells in the previous design).
- The water treatment building and the potable/fire protection water storage tank, demineralized water storage tanks, and fire pump skid have all been relocated to the area south of the administration/control/maintenance/warehouse building.
- The wastewater storage tank has been relocated to the area north of the cooling towers.
- The aqueous ammonia storage tanks have been relocated from the north side of the site to the area north of the west-cooling tower.

- The auxiliary boiler has been relocated to the area between the two HRSGs.
- A chiller and space for a future thermal (chilled water) storage tank have been added and are located in the area between the two HRSGs. This system will provide chilled water for cooling of the CT inlet air, replacing the fogging systems used in the previous configuration.
- Onsite gas compressors with fin-fan coolers have been added and are located in the area north of the east-cooling tower.
- The natural gas metering area has been relocated to the south side of the east-cooling tower, thus allowing access by the gas company without the need to enter the energy center.
- Areas for gas conditioning equipment have been added on the north side of the HRSGs. These areas will include equipment to moisturize and filter the fuel gas prior to use in the CTs.
- The area where hydrogen tube trailers will be parked has been relocated to the space between the generator step-up transformers, thus providing a more central location.
- Condensate storage tanks have been added and are located north of the STs.
- A second standby generator has been added such that each CT / ST / HRSG train now has a dedicated standby generator. The standby generators are located south of the respective HRSG stacks.
- With only two generator connections and a single outgoing 500 kV transmission line, the switchyard has been changed to a radial-feed configuration instead of a ring bus configuration, thus reducing the size of the switchyard.
- The large switchgear building has been replaced by a number of smaller power distribution centers (PDC) strategically located to be closer to the loads served.
- The large storm water pond south of the cooling tower has been deleted. Storm water from the IEEC will instead discharge directly into a regional flood control channel that will run from east to west across the southerly 100 feet of the IEEC project site. The flood control channel will be constructed, owned, and operated by the Riverside County Flood Control and Water Conservation District.

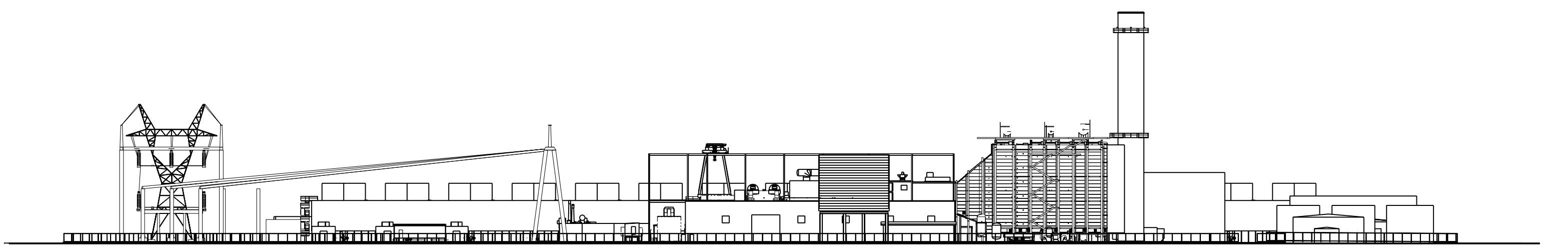
2.1.2 Process Description

The energy center will still feature two CTs equipped with dry, the low oxides of nitrogen (NOx) combustors. The turbine model, however, will be new the GE S107H System, instead of the PG7251(FB), or 7FB, CTs used in the previous configuration. Each GE S107H System includes a dedicated ST with the CT and ST sharing a common shaft line and generator. The H System is the most advanced combined-cycle system produced by GE Energy. The GE S107H System offers more output and a higher thermal efficiency than the 7FB.

Figure 2-1. General Arrangement



VIEW LOOKING NORTH



VIEW LOOKING SOUTH

50 0 50 100 150

SCALE IN FEET

PARSONS E&C

GE POWER SYSTEMS

GENERAL ELECTRIC COMPANY
GENERAL ELECTRIC INTERNATIONAL, INC.
GLOBAL POWER PLANT SYSTEMS DEPARTMENT
Schenectady, NY – USA

CLIENT/PROJECT TITLE

INLAND EMPIRE
ENERGY CENTER
AMENDMENT NO. 1

ELEVATIONS - VIEWS TOWARDS
NORTH & SOUTH
FIGURE 2-2

SCALE 1"=50'

DRAWING NO. M001-SK-9GA-002

REV -

	FAC	PIPING	I & C	ELECT	MECH	CIVIL	STRUC

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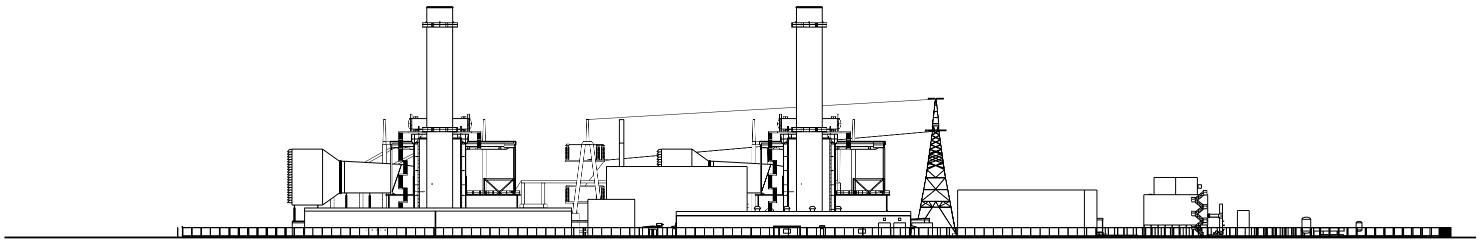
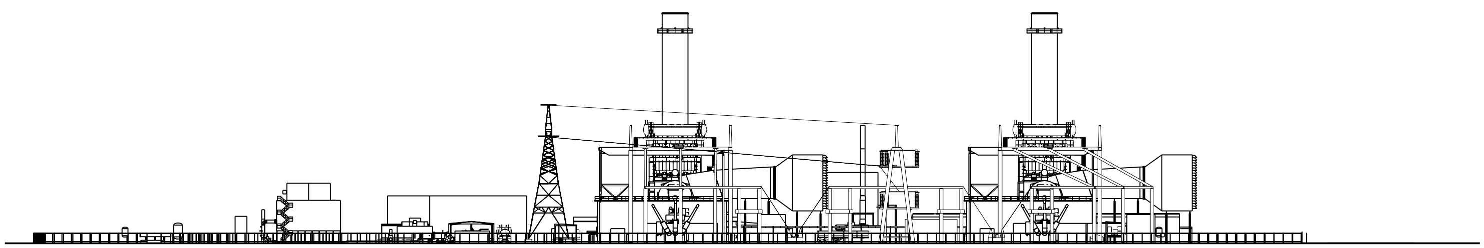


VIEW LOOKING EAST



VIEW LOOKING WEST

50 0 50 100 150

SCALE IN FEET

PARSONS E&C

GE POWER SYSTEMS

GENERAL ELECTRIC COMPANY
GENERAL ELECTRIC INTERNATIONAL, INC.
GLOBAL POWER PLANT SYSTEMS DEPARTMENT
Schenectady, NY - USA

CLIENT/PROJECT TITLE

INLAND EMPIRE
ENERGY CENTER
AMENDMENT NO. 1

ELEVATIONS - VIEWS TOWARDS
EAST & WEST
FIGURE 2-3

SCALE 1"=50'

DRAWING NO. M001-SK-9GA-003

REV -

FAC	PIPING	I & C	ELECT	MECH	CIVIL	STRUC

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The higher thermal efficiency is a function of the higher firing temperature, higher compression ratio, and steam-cooled CT. Each of the two condensing STs will be arranged in a down-exhaust configuration with a deaerating surface condenser installed under the ST. Two 8-cell cooling towers, one for each ST, will be used instead of a single 14-cell tower.

As with the previous configuration, the exhaust from each CT will discharge into a dedicated three-pressure HRSG. The duct-firing capability has been eliminated. As with the previous configuration, each HRSG will include a selective catalytic reduction (SCR) system for the reduction in NOx emissions and an oxidation catalyst for the reduction in carbon monoxide (CO) emissions. The auxiliary boiler has been increased in size from 100,000 lb/hr to 120,000 lb/hr and will include an SCR. In contrast with the previous design, however, it will not feature an oxidation catalyst. There will be two 2,000 kW diesel-fired standby generators, instead of the single 1,000 kW natural gas-fired generator featured in the previous design. The standby generators will be provided with soot filters for the reduction of particulate emissions. The diesel fire pump size has been decreased from 370 hp to 300 hp.

A heat and mass balance diagram for a single GE S107H System is shown in Figure 2-4. Heat and mass balance data, for base load operation at average ambient conditions, with CT inlet air cooling, are presented in Table 2-1. At these conditions, each GE S107H System will produce approximately 405 MW (gross) of power and consume approximately 2,503 MMBtu/hr of natural gas on a higher heating value (HHV) basis. The net energy center power output, after taking away auxiliary loads of 20 MW, is approximately 790 MW. This fuel consumption and net output equates to a heat rate of about 6,336 Btu/kW-hr (HHV), or about 5,729 Btu/kW-hr on a lower heating value (LHV) basis.

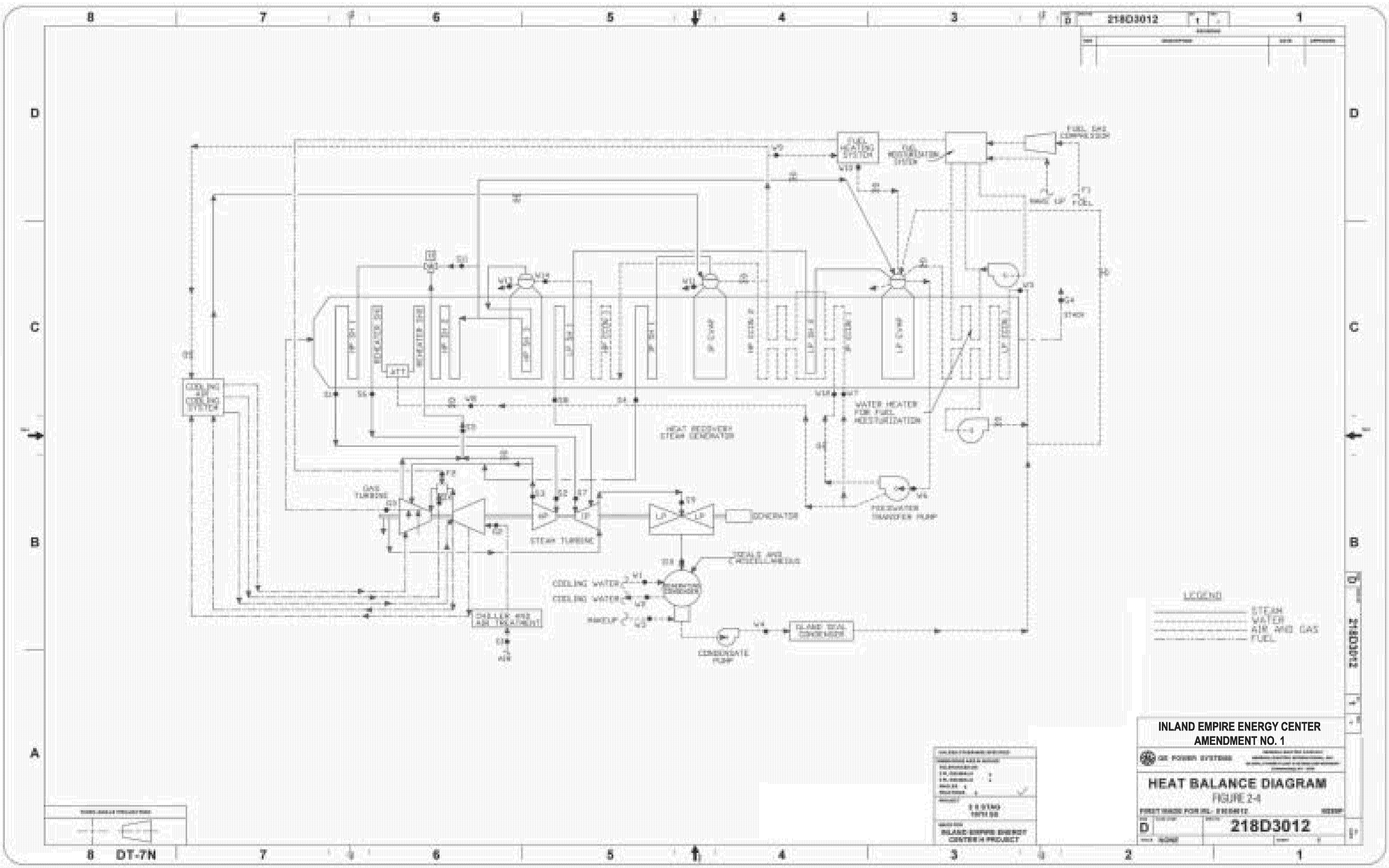
TABLE 2-1
Heat/Mass Balance Data

Figure 2-4 Number	Description	Flow 10^3 lb/hr	Pressure psia	Temperature deg. F
G1	Ambient Air	4,527	14.0	63
G2	Gas Turbine Inlet	4,527	13.8	48
G3	Gas Turbine Exhaust	4,720	14.7	1,088
G4	HRSG Stack Inlet	4,720	14.0	166
F1	Fuel at Supply	110	565	80
F2	Fuel at Gas Turbine Inlet	128	640	440
S1	HP Superheater Exit	600	1,787	1,013
S2	HP Turbine Throttle	600	1,743	1,010
S3	HP Turbine Exhaust	574	555	707
S4	IP Superheater Exit	103	577	519
S5	Reheater Inlet	661	396	833
S6	Reheater Exit	661	379	1,011

Figure 2-4 Number	Description	Flow 10^3 lb/hr	Pressure psia	Temperature deg. F
S7	IP Turbine Admission	661	371	1,009
S8	LP Superheater Exit	61	112	624
S9	LP Turbine Admission	750	46.9	497
S10	LP Turbine Exhaust	750	0.663	88
S11	HP Steam Attemperation	0	1,824	653
W1	Condenser Cooling Water Inlet	45,440	41.7	66
W2	Condenser Cooling Water Outlet	45,440	31.7	81
W3	Feedwater Makeup	5	0.7	70
W4	Condensate Pump Discharge	764	447	89
W5	LP Economizer Inlet	764	406	94
W6	Feedwater Transfer Pump Inlet	779	151	338
W7	IP Economizer Inlet	180	868	339
W8	Reheat Steam Attemperation	0	924	339
W9	IP Economizer Water to Fuel Heating	77	859	479
W10	Water Discharge from Fuel Heating	77	849	361
W11	IP Drum Blowdown	0	598	486
W12	HP Economizer Inlet	600	1,899	345
W13	HP Drum Blowdown	0	1,843	624

The thermodynamic cycle is very similar to that of the original configuration. The following is a summary of the key differences:

- A chilled water system will be used to cool the CT inlet air on warm and hot days, instead of a fogging system. The chilled water system allows a greater degree of cooling on hot days and also extends the range of ambient conditions over which inlet cooling may be used. The net result is a greater output capability on warm and hot days.
- The CT fuel gas is moisturized prior to injection into the CT. This increases the mass flow through the CT, thus increasing the power output.
- The GE S107H System uses an integrated heat transfer system in which some gas turbine buckets and nozzles are steam cooled. The system involves a closed-loop mechanism in which a portion of the cold reheat steam is passed through components of the CT. The steam exiting the CT is recombined with the remaining cold reheat steam prior to being


INLAND EMPIRE ENERGY CENTER
AMENDMENT NO. 1
GE POWER SYSTEMS
HEAT BALANCE DIAGRAM
FIGURE 2-4
218D3012
DT-7N
LEGEND
STEAM
WATER
AIR AND GAS
FUEL
FUEL GAS COMPRESSOR
FUEL HEATING SYSTEM
FUEL MOISTURIZATION SYSTEM
MAKE UP
FUEL
STACK
COOLING AIR COOLING SYSTEM
HEAT RECOVERY STEAM GENERATOR
WATER HEATER FOR FUEL MOISTURIZATION
FEEDWATER TRANSFER PUMP
GAS TURBINE
STEAM TURBINE
GENERATOR
SEALS AND MISCELLANEOUS
COOLING WATER
COOLING WATER
MAKEUP
CHILLER AND AIR TREATMENT
CONDENSATE PUMP
GLAND SEAL CONDENSER

returned to the reheater sections of the HRSG. This allows the power turbine to operate at higher firing temperatures, which in turn allows for dramatic improvements in fuel efficiency. Despite the high firing temperatures, the steam-cooling enables the CT to operate with moderate combustion temperatures, thus maintaining low emissions levels. With the previous generation of CTs, compressor discharge air was used to cool stage 1 nozzles and downstream rotational and stationary turbine components. However, this reduced cycle performance. With closed-loop steam cooling, the steam cools portions of the CT while it picks up heat for use in the ST, thus converting waste heat into usable output.

- In the previous configuration, HRSG duct firing would have been used to generate additional steam to provide peaking power via the ST. This peaking capacity would have been generated at a higher heat rate than the base load combined-cycle power, but at a lower incremental heat rate than a CT operated in simple-cycle mode. In the new configuration, the capability for generating peaking energy via HRSG duct firing has been eliminated. The fuel that would have been used for duct firing will instead be used in the CT to generate a greater amount of base load, highly efficient, combined-cycle energy.
- CT power augmentation via steam injection has been eliminated. This feature was included in the previous configuration to provide additional peaking capacity beyond that produced by HRSG duct firing.
- Two 8-cell cooling towers are now provided instead of a single 14-cell tower. The circulating water flow for each cooling tower will be approximately 90,000 gallons per minute (gpm).

2.1.3 Electrical Systems and Equipment

2.1.3.1 AC Power – Transmission

An updated single-line diagram of the facility's electrical system is presented in Figure 2-5. Power will be generated by the two GE S107H Systems at 19.5 kV and then stepped up to 500 kV for transmission to the grid. With two generators instead of three, the IEEC switchyard has been changed to a two-breaker radial feed configuration instead of the four-breaker ring bus configuration of the previous design.

2.1.3.2 AC Power – Distribution to Auxiliaries

The unit auxiliary transformers (UAT) will 19.5 kV to 4.16 kV three-winding transformers in the new design. The low side of each transformer will be capable of serving the auxiliary loads of both GE S107H Systems, thus increasing reliability.

2.1.3.3 DC Power Supply Systems

Each GE S107H Systems will be provided with 125-volt and 250-volt DC power systems with an uninterruptible power system (UPS) provided for each 125-volt DC system.

2.1.3.4 Standby Generators

A 2,000 kW diesel-fired standby generator will be connected to the essential services bus of each GE S107H System. These units will provide power to essential loads when power is not otherwise available through the 500 kV grid connection.

2.1.4 Fuel Supply and Use

The CTs and auxiliary boiler will be designed to burn only natural gas. The maximum natural gas requirement for the facility will remain approximately at 5,350 MMBtu/hr (HHV). The natural gas delivery pressure to the site is expected to be at least 435 psig. Because the GE S107H Systems require higher gas pressure than the 7FBs and the estimated delivery pressure to the project site has decreased, onsite compression will now be required. Three 50-percent-capacity gas compressors, each with a dedicated fin-fan cooler, will be provided.

2.1.5 Water Supply and Use

The Eastern Municipal Water District (EMWD) will deliver recycled water and raw water to the IEEC via an 0.2-mile 18 to 24-inch pipeline connecting to an existing 48-inch recycled water pipeline located in McLaughlin Road. Because of recent changes by EMWD in the operation of their recycled water system, the IEEC will now receive recycled water from the Perris Valley Regional Water Reclamation Facility (RWRF), Moreno Valley RWRF, and Temecula Valley RWRF. Because of the project's proximity to the Perris Valley RWRF, the recycled water for the IEEC will primarily be supplied from the Perris Valley RWRF.

Updated water balances are included as follows:

- Figure 2-6 – Operation at 63 degrees F with two CT/STs operating at 100% load with CT inlet air chilling
- Figure 2-7 – Operation at 98 degrees F with two CT/STs operating at 100% load with CT inlet air chilling

As with the previous configuration, EMWD will need to supplement recycled water with raw water provided by Metropolitan Water District (MWD). Table 2-2 presents updated estimates of the recycled and raw water use by year, based on conservative plant dispatch assumptions. This table reflects the conversion of agricultural areas to residential uses within EMWD's service territory, thus making more recycled water available for use by the IEEC in future years.

During the first full year of operation (2008), recycled water is projected to make up 95 percent of the water supplied to IEEC. After the third full year of operation, sufficient recycled water is projected to be available such that no supplemental raw water will be required. The raw water connection will still provide a backup source of water in the rare event that EMWD is unable to deliver recycled water to the IEEC.

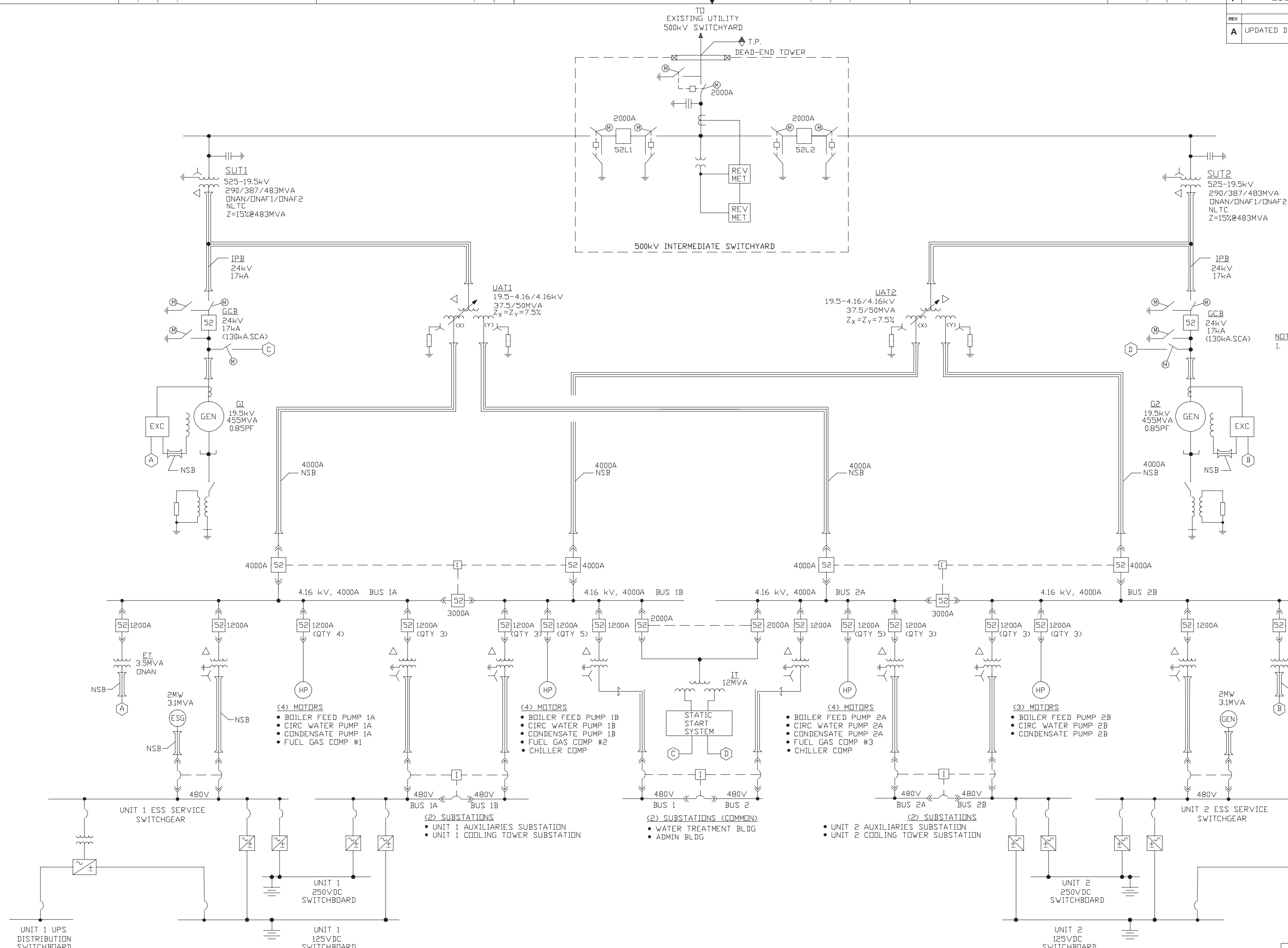
2.1.6 Recycled Water Pump Station

The Moreno Valley RWRF recycled water pump station, described in Section 3.4.9.1 of the Application for Certification, has since been constructed by EMWD. Thus, this pump station will no longer be included in the IEEC scope.

SIZE	DWG NO	SH	REV
F	230F4869	1	A

REVISIONS

REV	DESCRIPTION	DATE	APPROVED
A	UPDATED DWG PER ENG COMMENTS	04-11-11	PS/ALK



LEGEND

ESG	ESSENTIAL SERVICE GENERATOR
GCB	GENERATOR CIRCUIT BREAKER
ET	EXCITATION TRANSFORMER
EXC	EXCITER
IPB	ISOLATED PHASE BUS
IT	ISOLATION TRANSFORMER
NSB	NON-SEGREGATED BUS DUCT
SS	STATIC STARTER
SUT	MAIN SET-UP TRANSFORMER
UAT	UNIT AUXILIARY TRANSFORMER
TP	TERMINAL POINT

T.P. OTHERS / GE

NOTES
1. REDUNDANT REVENUE METERS SIEMANS MAXI'S 2510 (OR EQUAL)

UNLESS OTHERWISE SPECIFIED
DIMENSIONS ARE IN INCHES
TOLERANCES ON:
2 PL DECIMALS ±
3 PL DECIMALS ±
ANGLES ±
FRACTIONS ±

PROJECT 2 X 107H

MADE FOR INLAND EMPIRE ENERGY CENTER

THIRD ANGLE PROJECTION

INLAND EMPIRE ENERGY CENTER
AMENDMENT NO. 1

GE POWER SYSTEMS
GENERAL ELECTRIC COMPANY
GENERAL ELECTRIC INTERNATIONAL, INC.
GLOBAL POWER PLANT SYSTEMS DEPARTMENT
Schenectady, NY - USA

STATION ONE LINE DIA
CFDROB /*2

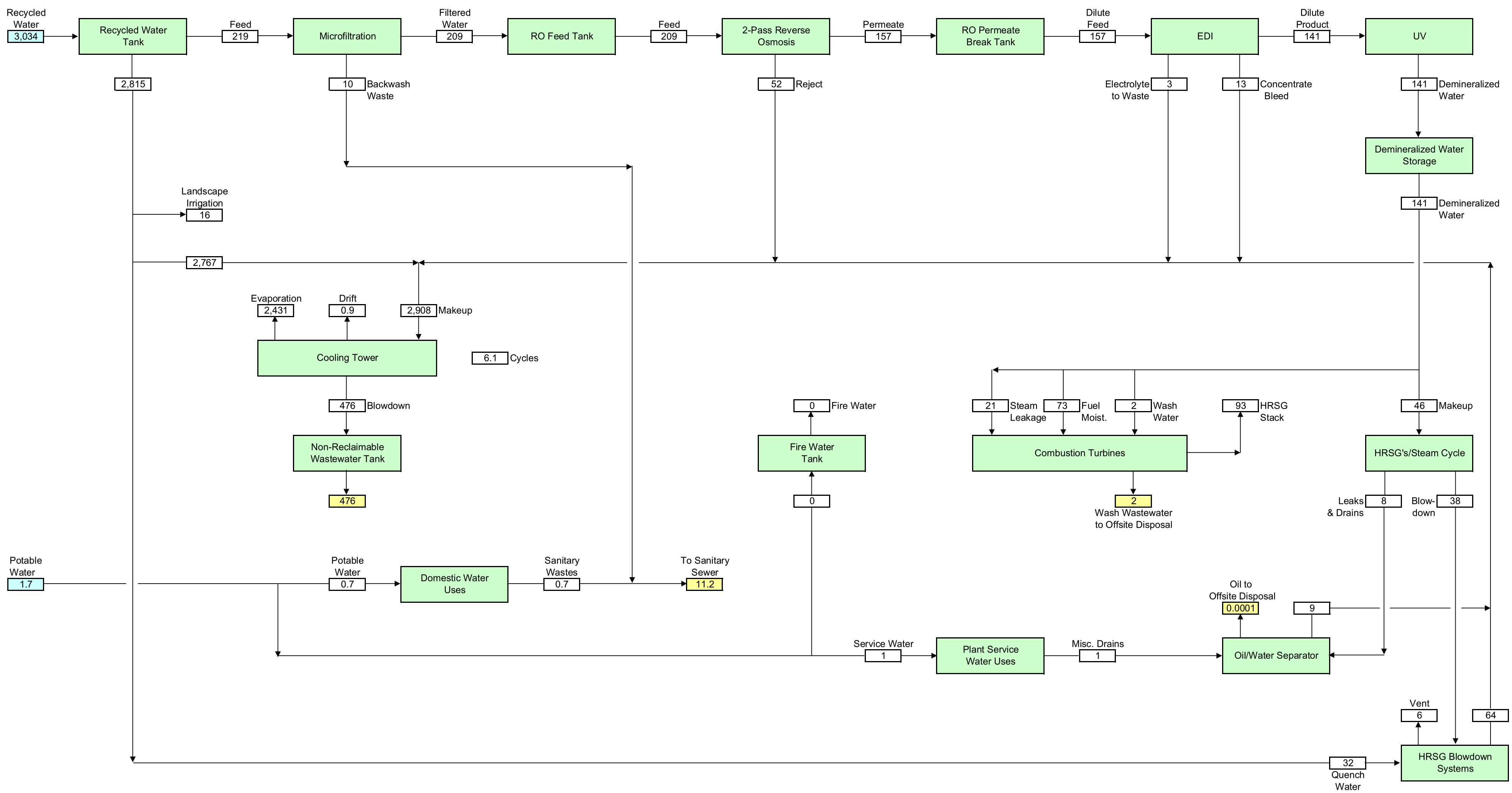
FIRST MADE FOR ML- 506S4001 E150

SIZE F | CAGE CODE | DWG NO 230F4869
SCALE NONE | SHEET 1

DT-7N

NAME: R:\2004\506s4001\STATION ONELINE\ E150_230F4869_001.dwg DATE: NOV 11, 2004 TIME: 2:15 PM

Notes:
1. All flow rates are in gallons per minute.
2. Backwash, regeneration, and landscape irrigation rates shown are average flows. Maximum instantaneous flows will be greater.
3. Fire flow shown is normal operation. Fire flow capacity is 2000 gpm.



Rev.	Description	By	Date
F	Issued for Amendment	JBM	10/01/04

Design Case: Average Base
Configuration: 2 x 2, NPD
Site Altitude: 1,445 ft
Dry Bulb Temp.: 63 deg. F
Wet Bulb Temp.: 53 deg. F
CT Inlet Chilling: Yes

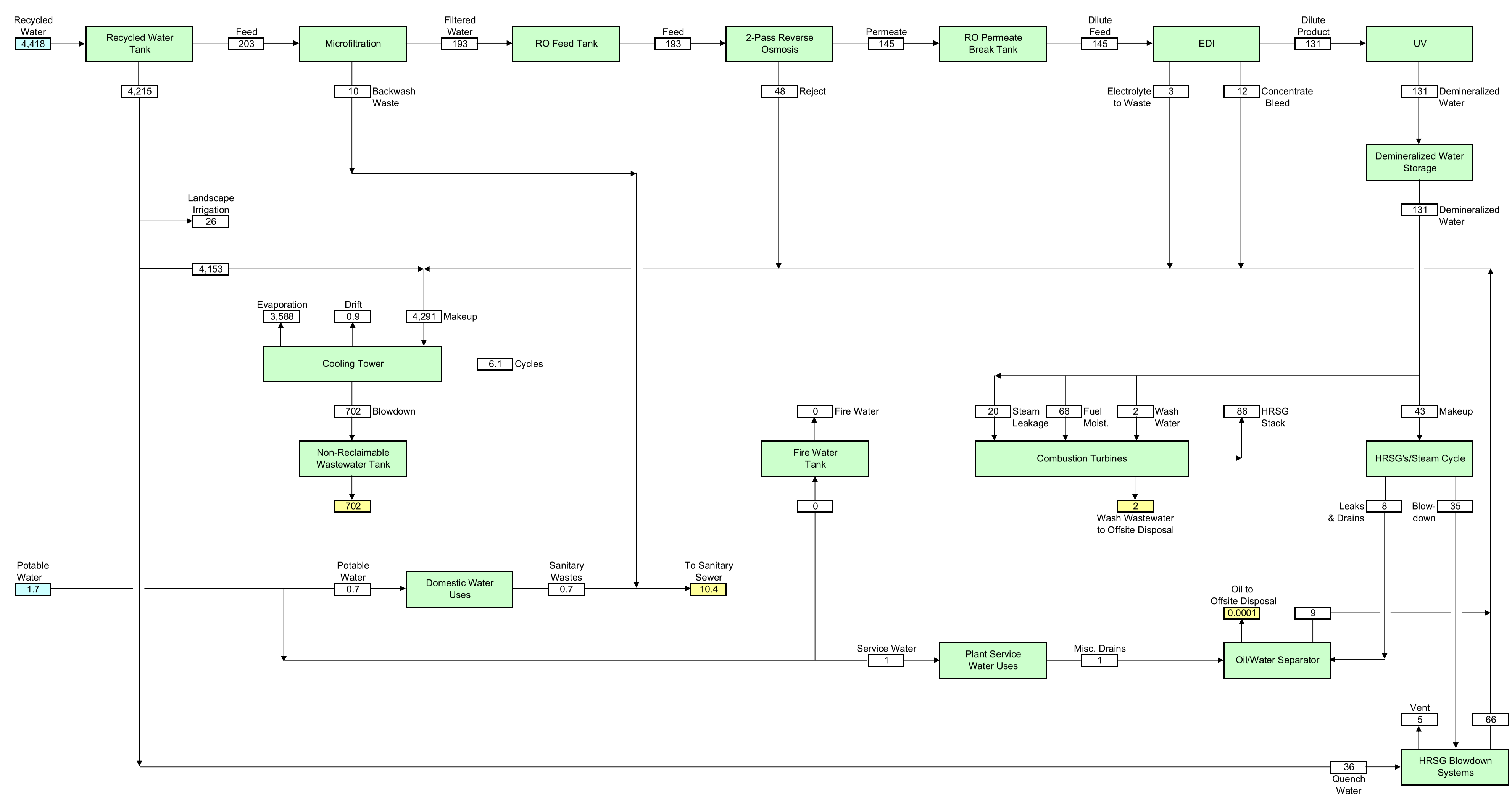
CALPINE

Rev.
F

Inland Empire Energy Center, Amendment No. 1

Figure 2-6 Water Balance, Summer Conditions

Notes:
1. All flow rates are in gallons per minute.
2. Backwash, regeneration, and landscape irrigation rates shown are average flows. Maximum instantaneous flows will be greater.
3. Fire flow shown is normal operation. Fire flow capacity is 2000 gpm.



Rev.	Description	By	Date
F	Issued for Amendment	JBM	10/01/04

Design Case:	Hot Base
Configuration:	2 x 2, NPD
Site Altitude:	1,445 ft
Dry Bulb Temp.:	98 deg. F
Wet Bulb Temp.:	71 deg. F
CT Inlet Chilling:	Yes

CALPINE

Rev. F

Inland Empire Energy Center, Amendment No. 1

Figure 2-7 Water Balance, Summer Conditions

TABLE 2-2
Projected Summary of Recycled and Raw Water Use by Year (acre-ft/year)

Year	Recycled Water	Raw Water	Total
2007	1,211	0	1,211
2008	4,610	232	4,842
2009	4,750	92	4,842
2010	4,823	19	4,842
2011	4,842	0	4,842
2012	4,842	0	4,842
2013	4,842	0	4,842
2014	4,842	0	4,842
2015	4,842	0	4,842
2016	4,842	0	4,842
2017	4,842	0	4,842
2018	4,842	0	4,842
2019	4,842	0	4,842
2020	4,842	0	4,842

2.1.7 Water Consumption Requirements

Daily and annual consumption requirements are summarized in Table 2-3. The daily requirements shown are estimated quantities based on the plant operating at base load, with CT inlet air chilling. The average daily value is based on operation at average ambient conditions (63 degrees F dry bulb, 53 degrees F wet bulb), whereas the maximum daily value is based on operation at the summer design conditions (98 degrees F dry bulb, 71 degrees F wet bulb). The average annual consumption is based on an annual capacity factor of 80 percent, whereas the maximum annual consumption is based on an annual capacity factor of 94 percent.

TABLE 2-3
Daily and Annual Average and Maximum Water Consumption Requirements

Water Consumption Requirements	Amount
Average Daily (US gal x 1000)	4,371
Maximum Daily (US gal x 1000)	6,364
Average Annual (acre-feet)	4,180
Maximum Annual (acre-feet)	4,842

2.1.7.1 Water Treatment

As shown in Figures 2-6 and 2-7, the proposed water treatment and water uses remain similar to those of the previous design, with exception of the following:

- Onsite electro-deionization (EDI) units have replaced the offsite-regenerated mixed-bed units as the polishing step in the production of demineralized water.
- An ultraviolet (UV) disinfection process has been added downstream of the EDI units.
- CT steam injection for power augmentation has been eliminated.
- CT inlet air fogging has been eliminated (replaced with inlet air chilling).
- Fuel moisturization has been added (a new demineralized water demand).

2.1.8 Water Tanks

Changes to the water tank capacities are as follows:

- The recycled water storage tank capacity has been reduced from 2.5 million gallons to 2.1 million gallons. This capacity remains sufficient for 8 hours of operational storage at the new maximum flow of 4,418 gpm.
- The two demineralized water storage tanks have been increased in capacity from 150,000 gallons each, to 210,000 gallons each, to provide additional reserve capacity.
- Two new condensate storage tanks have been added; one for each GE S107H System. Each tank will have a capacity of 50,000 gallons.
- Space has been allocated for a potential future thermal storage tank. This tank has been sized to store up to 4.5 million gallons of chilled water for CT inlet cooling.

2.1.9 Hazardous Materials Management

The new project configuration will require the use of one new chemical: HFC R-123 chiller refrigerant. Other than this material, the chemicals used and maximum quantities stored onsite will be within those listed in Appendix C of the Hazardous Materials Management section of the Commission Decision. See Section 3.5 for further discussion of HFC R-123.

As described above under Section 2.2.1 Energy Center Site Arrangement, the storage locations of two of the hazardous materials have been revised as follows:

- The aqueous ammonia storage tanks have been relocated from the north side of the site to the area north of the west-cooling tower.
- The area where hydrogen tube trailers will be parked has been relocated to the space between the generator step-up transformers, thus providing a more central location.

2.1.10 Air Emissions Control and Monitoring

The GE S107H Systems will be equipped with dry low-NO_X (DLN) combustors, capable of controlling turbine exhaust NO_X emissions to approximately 15 ppmvd at 15 percent oxygen (@ 15% O_2) during normal operation. Selective catalytic reduction systems, located within the HRSGs, will further reduce NO_X emissions to a maximum of 2.0 ppmvd @ 15% O_2, measured at the stacks during normal operation. Stack emissions of ammonia will not exceed 5 ppmvd @ 15% O_2, during normal operation, as required by the South Coast Air Quality Management District (SCAQMD). Oxidation catalyst will be included in the HRSGs to limit carbon monoxide (CO) emissions to 3.0 ppmvd @ 15% O_2 and to ensure that emission of VOC are controlled to less then 2.0 ppmvd @ 15% O_2.

The auxiliary boiler will be equipped with a low-emissions burner and SCR system, capable of meeting stack emissions levels of 7 ppmvd NO_X, 50 ppmvd CO, and 10 ppmvd VOC, all at 3 percent oxygen.

2.1.11 Fire Protection

The plant fire protection system will normally be pressurized by EMWD's potable water system. The onsite electric jockey pump and electric main fire pump will be deleted from the scope of the plant fire protection system. In the event of inadequate pressure from EMWD's potable water system, the onsite storage and diesel-driven fire pump will be used to provide fire protection water for the IEEC.

2.2 Energy Center Civil/Structural Features

2.2.1 Combustion Turbines, Steam Turbines, HRSGs, and BOP Equipment

Each GE S107H Systems, including CT, ST, and generator, will be mounted on a concrete pedestal, elevated approximately 36 feet above grade. The HRSGs will be mounted at grade on reinforced concrete mat foundations. The surface condensers will be installed at grade under their respective STs. The two generator step-up transformers, auxiliary transformers, and balance-of-plant (BOP) mechanical and electrical equipment will generally be installed at grade level on individual reinforced concrete pads.

2.2.2 HRSG Stacks

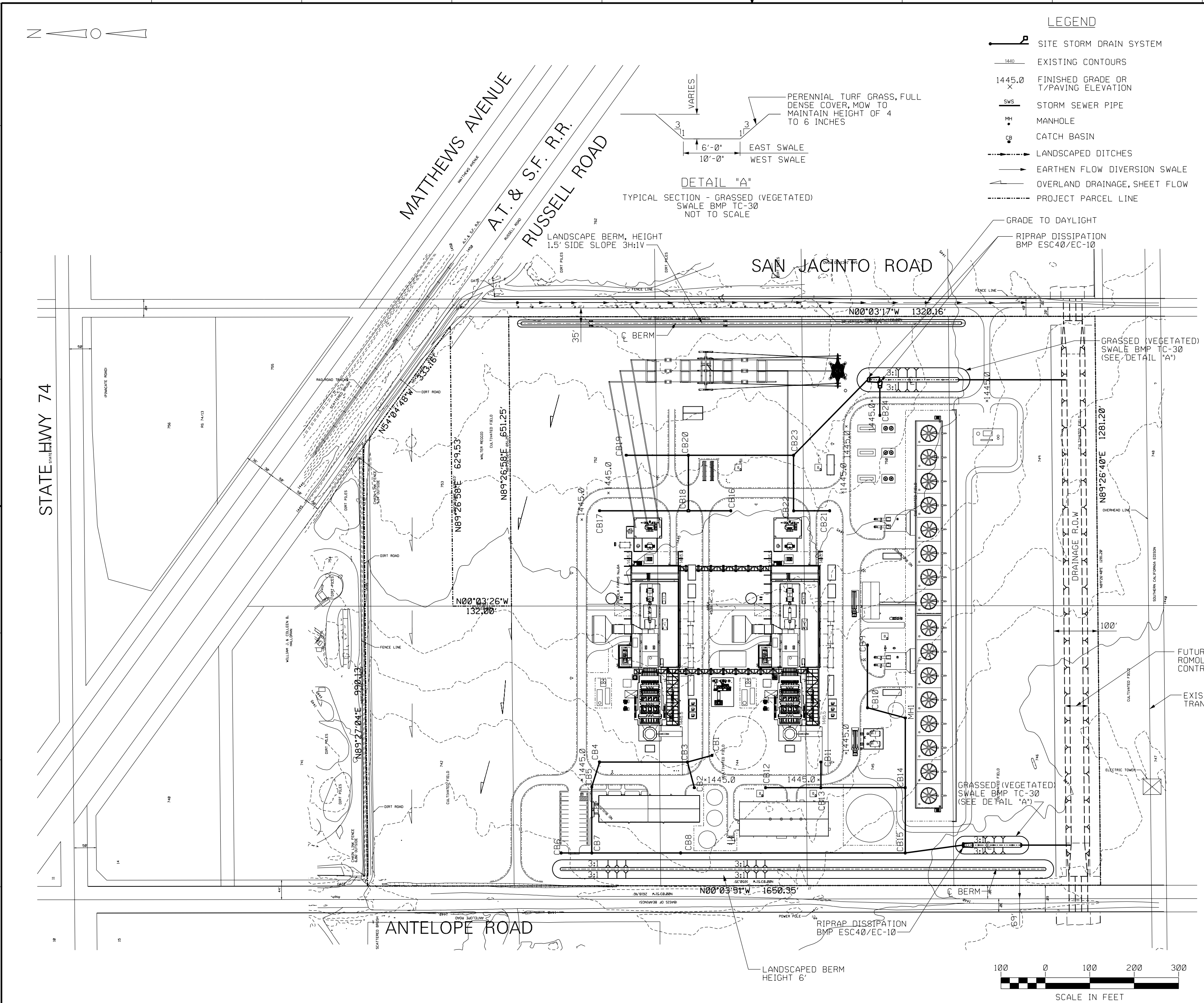
In the previous configuration, the HRSG stacks were self-supporting and installed side-by-side, requiring a significant amount of breeching to connect the stacks to the HRSGs. In the GE S107H System, the stacks will be installed in the conventional fashion, directly connected to the end of their respective HRSGs.

2.2.3 Buildings and Enclosures

Although the administration / control / maintenance / warehouse building and water treatment buildings will occupy approximately the same plot area as in the previous design; the administration and control portion is now two-story. The additional floor space is required to provide more offices and a larger parts storage area, both needed because of the change to the GE S107H Systems.

2.2.4 Site Drainage

The revised grading and drainage plan for the IEEC is shown in Figure 2-8. Off-site storm water runoff will be diverted around the improved facilities using a combination of berms and swales, generally draining from the northeast to the southwest. A shallow cut-off ditch graded within the San Jacinto Road right-of-way will collect off-site storm water flowing toward the site from the northeast and route it to the south where it will discharge into a County flood control channel. The County flood control channel will be a concrete-lined trapezoidal channel occupying a 100-foot wide strip along the southern edge of the project



NOTES:

1. ALL MANHOLES, CATCH BASINS, CHANNEL SECTIONS AND EROSION CONTROL MEASURES SHALL BE PER RCFC&WCD'S DESIGN STANDARD DRAWINGS AND CALIFORNIA DEPT. OF TRANSPORTATION STANDARD SPECIFICATIONS.
2. BASED ON THE CURRENT DEFINED FLOODPLAN MODEL, NONE OF THE SUBJECT PROPERTY IS WITHIN THE FEMA 100-YEAR FLOODPLAIN.
3. THE EARTHEN FLOW DIVERSION SWALE IN SAN JACINTO ROAD ALONG THE EASTERN BOUNDARY IS DESIGNED TO INTERCEPT THE OFFSITE WATERSHED FLOW OF APPROXIMATELY 407 CFS BASED ON A 100-YEAR RUNOFF FOR A 1-HOUR STORM.
4. PLANT FINISHED GRADE ELEVATION = 1445.5 FT (HIGHPOINT), TOP OF FOUNDATIONS/TOP OF FLOOR = 1446.0 FT.
5. PLANT ONSITE DRAINAGE SYSTEM IS DESIGNED FOR A 100-YEAR DESIGN DISCHARGE.
6. ALL AREAS WITHIN THE PLANT SHALL BE GRADED TOWARDS THE NEAREST CATCH BASIN/DITCH.
7. THERE ARE NO EXISTING STORM DRAINS ON THIS SITE.
8. CONTRUCT JUNCTIONS OF CULVERT OUTFALLS WITH RCFC&WCD ROMOLAND MDP FLOOD CONTROL CHANNEL PER RCFC&WCD STANDARD DRAWING JS232.
9. THE RCFD&WCD FUTURE ROMOLAND MDP FLOOD CONTROL PROJECT IS SCHEDULED TO BE OPERATIONAL IN SUMMER 2006. THIS SCHEDULE COINCIDES WITH THE INSTALLATION OF PERMANENT DRAINAGE FACILITIES FOR THE PLANT SITE.
10. WHERE TWO BMP DESIGNATIONS ARE SHOWN ON THE PLAN, THE DESIGNATION ON THE LEFT IS THE FORMER SWQTF, CALIFORNIA STORMWATER BEST MANAGEMENT PRACTICE HANDBOOK DESIGNATION AND THE DESIGNATION ON THE RIGHT IS THE CURRENT CASQA STORMWATER BEST MANAGEMENT HANDBOOK DESIGNATION. WHERE ONLY ON DESIGNATION IS SHOWN, IT REFERS TO THE CURRENT CASQA BMP DESIGNATION.

REFERENCE:

1. TOPOGRAPHY AND PROPERTY BOUNDARIES ARE FROM '00340.DWG' FILE PROVIDED BY CALPINE.

PARSONS E&C

GE POWER SYSTEMS — GENERAL ELECTRIC COMPANY, GENERAL ELECTRIC INTERNATIONAL, INC., GLOBAL POWER PLANT SYSTEMS DEPARTMENT, Schenectady, NY • USA

CLIENT/PROJECT TITLE

INLAND EMPIRE
ENERGY CENTER
AMENDMENT NO. 1

FIGURE 2-8
GRADING AND DRAINAGE
PLAN

SCALE 1" = 100'

DRAWING NO. C100-SK-9PMT-003 REV -

FAC PIPING I & C ELECT MECH CIVIL STRUC

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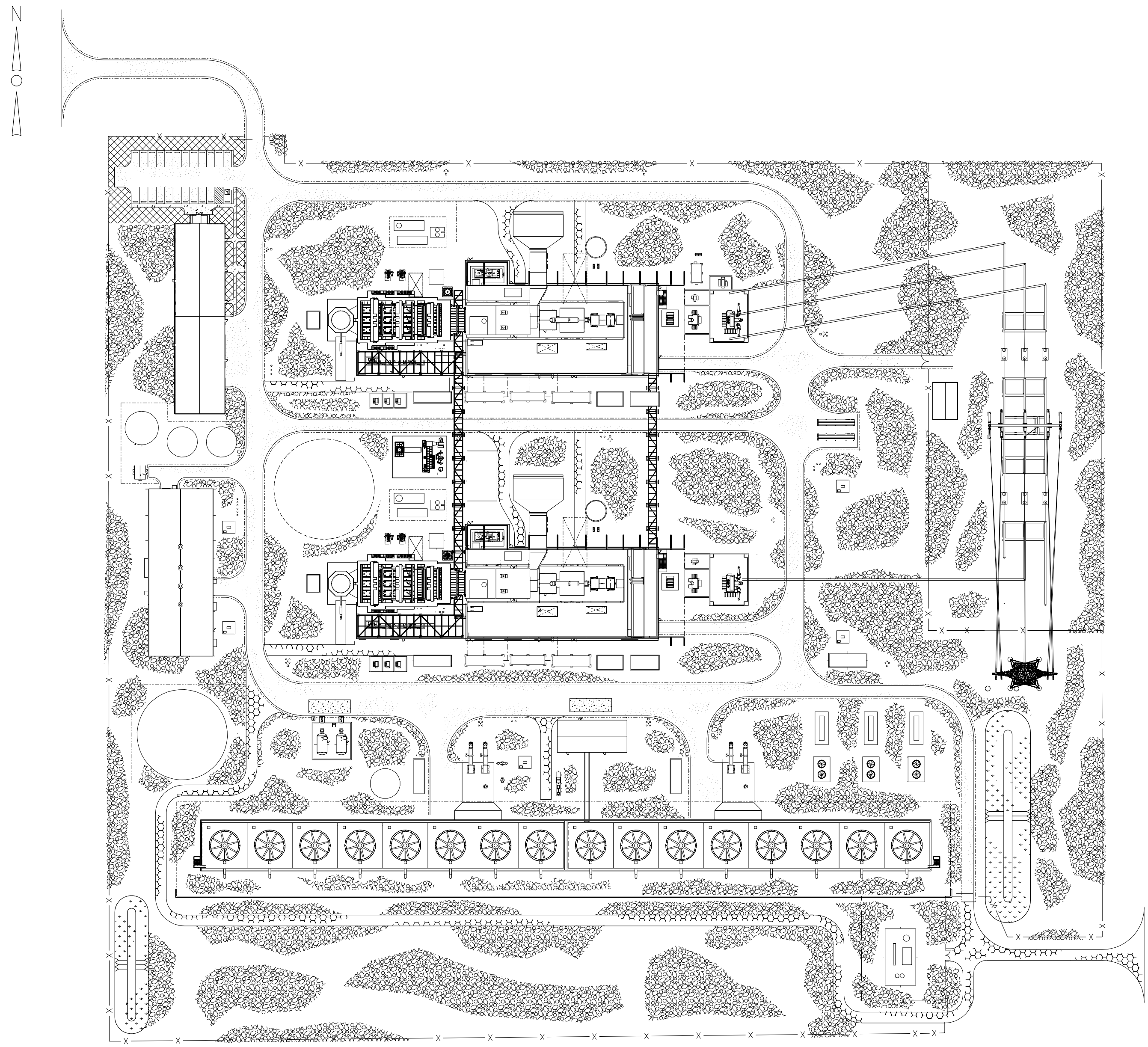

LEGEND

- ASPHALT
- CONCRETE
- GRAVEL SURFACING
- GRASS
- GRAVEL ROAD SURFACING
- LANDSCAPING

60 0 60 120 180

SCALE IN FEET

PARSONS E&C

GE POWER SYSTEMS
GENERAL ELECTRIC COMPANY
GENERAL ELECTRIC INTERNATIONAL, INC.
GLOBAL POWER PLANT SYSTEMS DEPARTMENT
Schenectady, NY – USA

CLIENT/PROJECT TITLE

INLAND EMPIRE
ENERGY CENTER
AMENDMENT NO. 1

PLANT AREA SURFACING PLAN
FIGURE 2-9

SCALE

DRAWING NO. C100-SK-9PMT-001

REV -

FAC	PIPING	I & C	ELECT	MECH	CIVIL	STRUC

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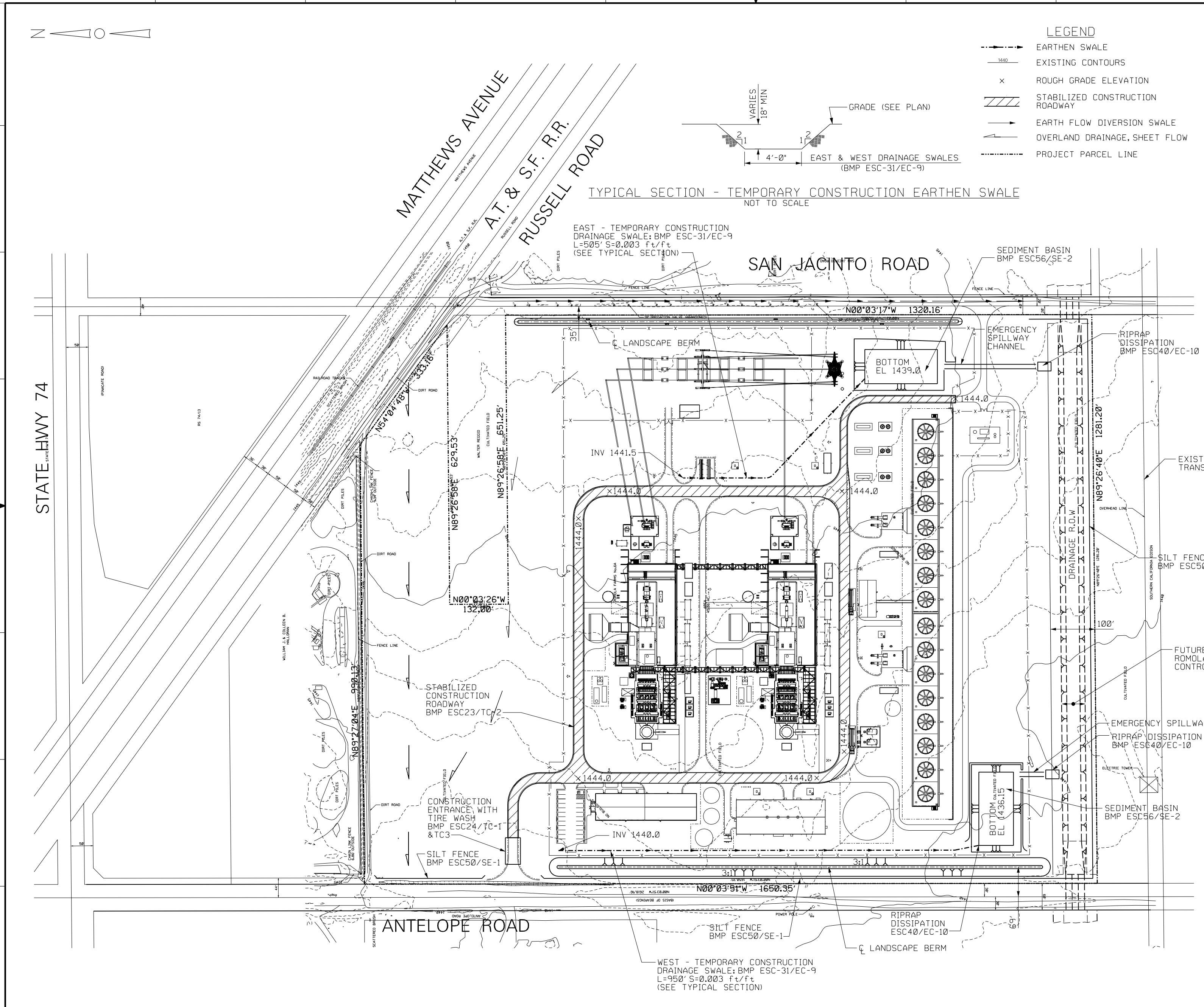
PE&C-DATE: 03-Mar-05 11:55



NOTES:

1. CHANNEL SECTIONS AND EROSION CONTROL MEASURES SHALL BE PER RIVERSIDE COUNTY FLOOD CONTROL AND WATER CONSERVATION DISTRICT'S DESIGN STANDARD DRAWINGS AND CALIFORNIA DEPT. OF TRANSPORTATION STANDARD SPECIFICATIONS.
2. BASED ON THE CURRENT DEFINED FLOODPLAN MODEL, NONE OF THE SUBJECT PROPERTY IS WITHIN THE FEMA 100-YEAR FLOODPLAIN.
3. THE EARTHEN FLOW DIVERSION SWALE IN SAN JACINTO ROAD ALONG THE EASTERN BOUNDARY IS DESIGNED TO INTERCEPT THE OFFSITE WATERSHED FLOW OF APPROXIMATELY 407 CFS BASED ON A 100-YEAR RUNOFF FOR A 1-HOUR STORM.
4. THE TEMPORARY CONSTRUCTION DRAINAGE SYSTEM IS DESIGNED FOR A 10-YEAR DESIGN DISCHARGE.
5. ALL AREAS WITHIN THE PLANT SHALL BE GRADED TOWARDS THE NEAREST DITCH.
6. THERE ARE NO EXISTING STORM DRAINS ON THIS SITE.
7. FOR DETAILS OF SEDIMENT BASINS, SEE DWG. IEEC-1-SK-045-735-004.
8. WHERE TWO BMP DESIGNATIONS ARE SHOWN ON THE PLAN, THE DESIGNATION ON THE LEFT IS THE FORMER SWQTF, CALIFORNIA STORMWATER BEST MANAGEMENT PRACTICE HANDBOOK DESIGNATION AND THE DESIGNATION ON THE RIGHT IS THE CURRENT CASQA STORMWATER BEST MANAGEMENT HANDBOOK DESIGNATION. WHERE ONLY ONE DESIGNATION IS SHOWN, IT REFERS TO THE CURRENT CASQA BMP DESIGNATION.

REFERENCE:

1. TOPOGRAPHY AND PROPERTY BOUNDARIES ARE FROM "00340.DWG" FILE PROVIDED BY CALPINE.

PARSONS E&C

GE POWER SYSTEMS — GENERAL ELECTRIC COMPANY, GENERAL ELECTRIC INTERNATIONAL, INC., GLOBAL POWER PLANT SYSTEMS DEPARTMENT, Schenectady, NY – USA

CLIENT/PROJECT TITLE
INLAND EMPIRE ENERGY CENTER AMENDMENT NO. 1

FIGURE 2-10
CONSTRUCTION GRADING & DRAINAGE PLAN

SCALE 1"=100'
DRAWING NO. C100-SK-9PMT-002
REV -

PE&C-FILE: c100-sk-9pmt-002.dgn
PE&C-DATE: 03-Mar-05 11:56

property. The flood control channel is scheduled for construction during the same time frame as the IEEC. On-site storm water runoff within the IEEC fenced area will be collected by a series of catch basins and area drains and directed to vegetated swales and then discharged to the County flood control channel. Figure 2-9 is a surfacing plan showing the surfaces that will be impermeable and those that will be covered with gravel or grass. Storm water collected in curbed containment areas will be collected in the plant process drain system, routed through an oil-water separator, and then discharged to the cooling tower basin.

Figure 2-10 shows the grading and drainage plan for the IEEC during the construction phase. Off-site storm water runoff will be diverted around the project site similar to that shown for the operating facility. For control of on-site runoff, north-south running earthen swales will be constructed on the east and west sides of the site to collect storm water and divert it to the sediment basins located at the south end of the site.

2.3 Transmission Facilities

A new System Impact Study (SIS) application was submitted to the California Independent System Operator (CAISO) on December 20, 2004 (see Appendix 2.0 for a copy of the application). CAISO deemed the application complete on January 10, 2005 (see Appendix 2.0 for a copy of CAISO's letter).

The previously proposed transmission line that will run from the IEEC to Southern California Edison's (SCE) Valley Substation remains adequate to carry the increased output associated with the GE S107H System. Given that the system impacts associated with the previous configuration were limited to equipment replacement within SCE's existing substations (i.e. no necessary transmission line upgrades), it is expected that the impacts will be similar under the new SIS.

2.4 Project Construction

2.4.1 Construction Schedule

Construction of the energy center from site preparation and grading to commercial operation is expected to take place from the summer of 2005 to the summer of 2008, a total of 36 months. The actual construction duration from the start of construction to substantial completion is estimated to be 26 months. Because the IEEC project will be the first installation of the GE S107H System, the commissioning phase will be longer than a typical combined-cycle project. In addition, there will be an extended period of normal operation, following the commissioning phase, prior to the declaration of commercial operation. Major milestones are listed in Table 2-4.

TABLE 2-4
Project Schedule Major Milestones

Activity	Date
Begin Construction	Third Quarter 2005
Begin Startup and Testing	Second Quarter 2007
Construction Substantially Complete	Third Quarter 2007
Commercial Operation	Third Quarter 2008

2.4.2 Construction Workforce

Construction by month and trade is shown in Table 2-5. The onsite workforce is expected to reach its peak of approximately 750 individuals during month 14 of construction. There will be an average monthly workforce of approximately 366 construction craft people, supervisory, support, and construction management personnel on site during construction.

2.4.3 Construction Traffic

Table 2-6 provides an estimate of the number of average and peak construction traffic during the construction period. Materials and equipment will be delivered by truck and possibly by rail. If rail deliveries are used, up to 200 railcars may be used to deliver heavy and large equipment to the site, thus offsetting a portion of the heavy truck traffic indicated in Table 2-6.

TABLE 2-6
Average and Peak Construction Traffic

Vehicle Type	Average Daily Round Trips	Peak Daily Round Trips(2)
Construction Workers(1)	244	500
Delivery	14	27
Heavy Trucks	6	26
Total	264	553

(1) Assumes that 1/3 of the workforce will carpool (1.5 persons per vehicle).
(2) “Peak” refers to scheduled peak months of construction (month14). Peak workforce during this month is expected to be up to 750 persons.

2.4.4 Construction Laydown and Parking

Figure 2-11 shows the construction laydown and parking areas and the general arrangement of temporary construction facilities[1]. The areas on the project site north and south of the plant site will still be used for construction laydown, temporary facilities, and parking. In addition, a new 9.6-acre area northwest of the project site, on the west side of Antelope

[1] This figure illustrates temporary project features that assume the addition of a construction laydown area that will be the subject of a future amendment.

TABLE 2-5
Construction Workforce by Trade by Month

Craft/Trade	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
I. Project Site																										
Boilemakers	-	-	-	-	9	17	36	71	68	75	146	159	158	159	141	164	149	78	57	32	9	-	-	-	-	-
Carpenters	3	6	12	17	21	24	24	30	33	27	48	42	42	42	38	44	33	26	27	24	24	12	14	9	8	4
Electricians	-	-	11	17	21	33	38	45	39	35	71	84	83	84	74	86	90	84	108	110	93	71	96	45	36	12
Ironworkers	3	6	15	18	18	21	30	44	44	38	66	71	69	71	63	72	66	42	27	29	24	17	14	5	3	2
Laborers	12	18	20	18	24	29	35	38	27	24	44	47	47	47	42	48	41	38	45	36	24	11	14	14	11	5
Pipefitters	-	-	8	14	21	29	47	71	62	56	99	107	105	105	93	108	96	68	45	29	24	6	9	5	3	2
Painters/ insulation	-	-	-	-	-	-	-	-	-	-	12	42	42	42	38	44	47	45	57	60	47	32	26	18	15	7
Bricklayers/ masons	-	-	-	2	2	3	5	5	3	3	5	3	3	3	3	3	3	2	3	3	3	2	3	5	3	2
Millwrights	-	-	-	-	-	-	5	5	11	12	23	26	26	26	23	26	27	24	32	27	24	21	14	18	15	7
Operating engineers	3	6	6	8	14	12	20	21	18	17	29	32	32	32	29	33	32	29	35	29	29	17	17	14	11	5
Contractor staff	12	18	18	17	29	33	44	54	45	39	71	75	75	75	66	78	74	75	90	78	65	51	45	45	36	12
Total site staff	33	54	89	108	158	200	281	381	348	324	611	686	680	684	608	704	656	509	525	455	365	237	249	176	140	58
II. Project Linear Facilities																										
Waste pipeline	-	-	-	-	-	-	-	-	-	-	-	-	3	26	26	26	3	-	-	-	-	-	-	-	-	-
Natural gas pipeline	-	-	-	-	-	-	-	-	-	-	3	21	21	22	21	3	-	-	-	-	-	-	-	-	-	-
Transmission line	-	-	-	-	-	-	-	-	-	-	-	-	3	18	18	3	-	-	-	-	-	-	-	-	-	-
Total linear	-	-	-	-	-	-	-	-	-	-	3	21	27	66	65	32	3	-	-	-	-	-	-	-	-	-
Grand Total	33	54	89	108	158	200	281	381	348	324	614	707	707	750	672	735	659	509	525	455	365	237	249	176	140	58

Road, will be used for construction worker parking and secondary laydown area. Table 2-7 lists the Assessor's Parcel Numbers and acreages of these new laydown and parking areas. The new laydown areas are as follows:

TABLE 2-7
Proposed New Construction Laydown Areas

APN	Owner Name	Street Frontage	Acres
351-150-039	Anderson	Antelope Road	4.86
351-150-040	Grabowski	Dawson Road	4.77
Total acres			9.63

2.4.5 Construction Water

Average daily use of construction water is estimated to be about 15,000 gallons, primarily for dust control and soil compaction. The peak water demand is estimated to be about 1,000,000 gallons per day, which will occur during the filling of the recycled water storage tank.

2.4.6 Construction Disturbance Area

The temporary disturbance area for construction of the power generation facility will increase to approximately 45.73 acres. The permanent disturbance area will remain approximately 38 acres.

2.5 Energy Center Operation

The IEEC will be staffed by 33 full-time personnel.

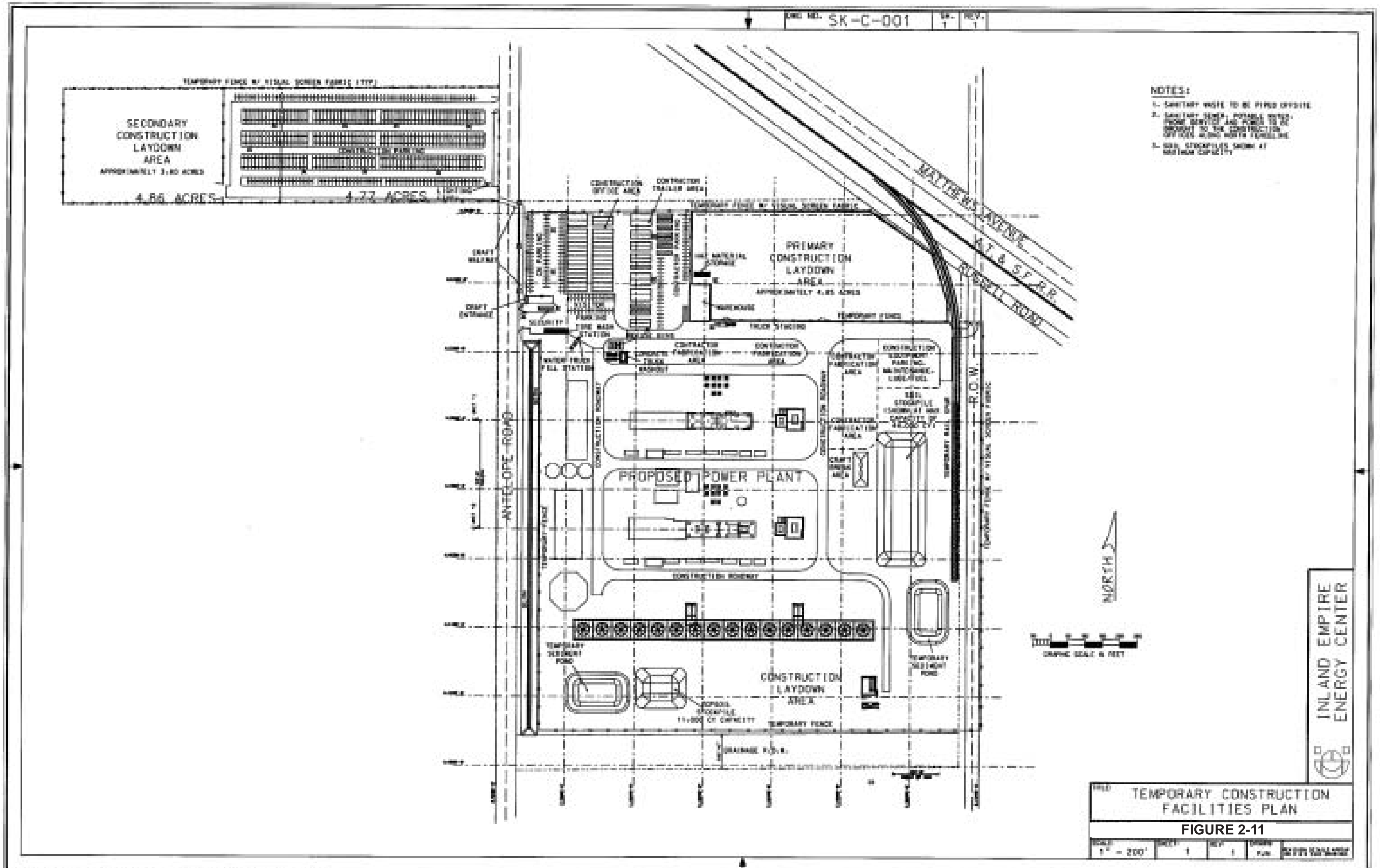


FIGURE 2-11

...\GA- Construction Services 11x1 03/09/2005 03:53:58 PM

3.0 Environmental Analysis of Proposed Project Amendment

The project changes proposed in this Amendment petition will permit the project owner to adopt the most efficient gas turbine technology available and will also permit additional construction parking and laydown area. The following sections provide an environmental analysis for each of 14 different discipline areas that addresses: (1) significant changes to the project area environmental baseline if these changes have taken place since the certification was granted and have a bearing on the environmental impact analyses for the amended project, and (2) significant potential changes to environmental impacts of the project that are a result of the technology change or the addition of construction parking and laydown areas. Each section includes an environmental analysis, followed by a list of any changes to the Conditions of Certification that are necessary because of the project Amendment changes, provided as a text mark-up.

The environmental disciplines are addressed in alphabetical order, as follows:

- 3.1 Air Quality
- 3.2 Biological Resources
- 3.3 Cultural Resources
- 3.4 Geology and Paleontology
- 3.5 Hazardous Materials Management
- 3.6 Land Use
- 3.7 Noise
- 3.8 Public Health
- 3.9 Socioeconomics
- 3.10 Soil and Water Resources
- 3.11 Traffic and Transportation
- 3.12 Visual Resources
- 3.13 Waste Management
- 3.14 Worker Safety and Fire Protection
- 3.15 LORS

3.1 Air Quality

As discussed in Section 2, the proposed new equipment will consist of two GE S107H systems, two 2,000 kW diesel standby generator engines, a diesel fire pump engine, and two mechanical draft evaporative cooling towers. As with the original project, the operation of this equipment will result in NOx, CO, VOC, SOx, and PM_{10} emissions. The following paragraphs provide an update to the environmental baseline and discuss the changes in the air quality impacts associated with the proposed equipment changes.

3.1.1 Environmental Baseline

Table 5.2-25 of the August 2001 AFC showed the maximum background ambient concentrations for the project area for 1997 to 2000. This table has been revised to reflect newer data that are now currently available. In the following table, the previous background levels are shown in parentheses. As shown in Table 3.1-1, for the most part the maximum background ambient levels for the project area have decreased.

TABLE 3.1-1
Maximum Background Concentrations for IEEC Project, 2000-2003 (σg/m^3)

Pollutant	Averaging Time	2000	2001	2002	2003	Maximum During Past 3 Years*
Perris Monitoring Station						
PM_{10}	24-Hour	87	86	100	116	116 *(139)*
	Annual (AAM)[a]	38.9	40.9	45.1	43.9	45 *(50)*
	Annual (AGM)[b]	34.9	40.8	45.0	--	45 *(44)*
Lake Elsinore Monitoring Station						
NO_2	1-Hour	144.8	171.1	139.1	139.1	171 *(211)*
	Annual	28.2	33.8	32.0	33.8	34 *(36)*
Riverside- Rubidoux Monitoring Station						
SO_2	1-Hour	278.2	49.7	41.9	47.1	50 *(278)*
	24-hour	91.7	23.5	7.9	31.4	31 *(92)*
	Annual	2.6	2.6	2.6	5.2	5 *(5)*
$PM_{2.5}$	24-Hour	--	77.0	73.0	72.0	77 *(n.a.)*
	Annual	--	30.1	28.9	27.7	30 *(n.a.)*
Riverside – Magnolia Monitoring Station						
CO	1-Hour	6,866	4,577	8,010	5,721	8,010 *(12,650)*
	8-Hour	4,865	5,126	4,291	3,810	5,126 *(6,302)*

* Previous values are shown in italics in parentheses
[a] Annual Arithmetic Mean
[b] Annual Geometric Mean

3.1.2 Environmental Consequences

The following paragraphs discuss the changes associated with the emission levels and ambient air quality impacts associated with the proposed equipment changes.

3.1.2.1 Emissions

The following Best Available Control Technology (BACT) levels for the gas turbines are required by the existing Conditions of Certification for the project:

- NOx: 2.0 ppmv @ 15% O2, 1-hour average (Condition AQ-22)
- CO: 3.0 ppmv @ 15% O2, 1-hour average (Condition AQ-23)
- VOC: 2.0 ppmv @ 15% O2, 1-hour average (Condition AQ-24)

These BACT levels remain unchanged for the proposed GE S107H Systems. Although the tables below show increases in emissions of some pollutants (particularly NOx), these increase are related to engine-specific changes in NOx emission rates during startup. There are similar, large decreases in CO emissions during startup as well. The remaining emission changes are relatively minor in nature.

Duct burners are no longer a part of the project design. With their removal, a worst-case base load operating condition was adopted for this Amendment. This worst-case base load operating profile, and design changes in auxiliaries resulted in annual emissions estimates very similar to the previous equipment configuration. These minor changes are listed below:

- There is a marginal increase in the overall maximum heat input to each gas turbine/HRSG from 2,510 MMBtu/hr (1,813 MMBtu/hr gas turbine, 697 MMBtu/hr duct burner) to 2,597 MMBtu/hr.
- The new auxiliary boiler is an increase in maximum heat input from 129 to 157 MMBtu/hr.
- The number of standby generator engines has increased from a single engine to two engines, and they have been changed from natural gas- to diesel-fired. The size of the standby generator engines has also increased from 1,467 hp to 2,848 hp.
- The emergency fire pump engine remains diesel, but the rating of the engine has decreased from 337 hp to 300 hp.
- The number of cooling towers has increased from a single tower to two towers, and the number of cells per tower has decreased from 14 cells per tower to 8 cells per tower. This results in a combined flow rate for the two towers of 179,194 gal/min, a slight increase from 169,847 gals/min.

Tables 5.2-18 and 5.2-21 of the August 2001 AFC summarized the emissions for the project. These tables have been revised to show the emissions associated with the proposed equipment changes. In these tables, the previous emission rates are shown in parentheses. As shown in Table 3.1-2 below, CO emissions decrease during gas turbine startups associated with the equipment change, and there is an increase in NOx emissions. VOC emissions during gas turbine startups remain unchanged. These changes in CO and NOx emissions during gas turbine startups are also reflected in Table 3.1-3, with an overall increase in NOx emissions for the project due mainly to higher NOx emissions during gas turbine startups. Likewise, the overall decrease in CO emissions for the project is due primarily to the lower gas turbine startup emission levels. The overall SOx emissions for the project have increased slightly, due to an expected increase in annual fuel use, and due to the change from natural gas- to diesel-fired standby generator engines. The slight increase in VOC emissions is due mainly to higher heat inputs to the gas turbines during worst-case base load operating conditions. The detailed emission calculations for the proposed equipment changes are enclosed as Appendix 3.1-A1.

TABLE 3.1-2
Expected Facility Startup and Shutdown Emission Rates (per gas turbine), IEEC Project*

	NOx	CO	VOC
Short Term Average Levels			
Startup or Shutdown, lbs/hour (single gas turbine in startup)	408 *(80)*	95 *(902)*	16 *(16)*
Startup or Shutdown, lbs/hour (combined level for both gas turbines in startup)	550 *(n.a.)*	190 *(n.a.)*	32 *(n.a.)*
Startup, lbs/start[a] (per gas turbine)	803 *(240)*	300 *(2,706)*	48 *(48)*
Long Term Average Levels[b]			
Startup or Shutdown, lbs/hour (per gas turbine)	125 *(80)*	50 *(100)*	16 *(16)*

* Previous values are shown in italics in parentheses
[a] For proposed new equipment, based on maximum of 6 hours per cold start. In August 2001 AFC, emissions were based on a 3-hour cold start.
[b] For NOx, based on an annual average. For CO and VOC, based on a 30-day average.

TABLE 3.1-3
Emissions from New Equipment (Gas Turbines/HRSGs, Auxiliary Boiler, Emergency Engines, and Cooling Towers), IEEC Project*

Equipment	NOx	SOx	CO	VOC	PM_{10}
Maximum Hourly Emissions (lbs/hr)					
Gas Turbines	550.0 *(102.7)*	3.7 *(3.5)*	190.0 *(935.2)*	32.0 *(22.3)*	20.0[b] *(31.9)*
Auxiliary Boiler	1.3 *(1.4)*	0.1 *(0.1)*	5.7 *(4.9)*	0.7 *(0.6)*	1.1 *(2.7)*
Fire Pump[a]	0.0 *(0.0)*	0.0 *(0.1)*	0.0 *(0.0)*	0.0 *(0.0)*	0.0 *(0.0)*
Standby Generators	41.8 *(4.9)*	1.0 *(0.0)*	6.4 *(6.5)*	0.8 *(4.9)*	0.2 *(0.5)*
Cooling Towers	--	--	--	--	3.5 *(3.3)*
Total	593.1 *(109.0)*	4.8 *(3.7)*	202.1 *(946.6)*	33.5 *(27.8)*	24.8 *(38.4)*
Maximum Daily Emissions (lbs/day)					
Gas Turbines	2,283.8 *(1,495.3)*	87.9 *(81.0)*	1,219.0 *(8,339.3)*	332.4 *(350.3)*	480.0 *(726.8)*
Auxiliary Boiler	31.6 *(11.2)*	2.7 *(0.7)*	137.5 *(39.2)*	15.7 *(4.8)*	26.9 *(21.6)*
Fire Pump[a]	0.0 *(0.0)*	0.0 *(0.1)*	0.0 *(0.0)*	0.0 *(0.0)*	0.0 *(0.0)*
Standby Generators	250.5 *(4.9)*	5.8 *(0.0)*	38.0 *(6.5)*	5.3 *(4.9)*	0.9 *(0.5)*
Cooling Towers	--	--	--	--	84.0 *(79.6)*
Total	2,565.9 *(1,511.2)*	96.4 *(81.8)*	1,394.5 *(8,385.0)*	353.4 *(359.9)*	591.8 *(828.5)*
Maximum Annual Emissions (tpy)					
Gas Turbines	210.9 *(166.7)*	16.1 *(13.9)*	181.8 *(590.8)*	61.3 *(46.6)*	87.6 *(123.7)*
Auxiliary Boiler	1.5 *(2.1)*	0.1 *(0.1)*	6.7 *(7.4)*	0.8 *(0.9)*	1.3 *(4.1)*
Fire Pump	0.1 *(0.1)*	0.0 *(0.0)*	0.0 *(0.1)*	0.0 *(0.0)*	0.0 *(0.0)*
Standby Generators	2.1 *(0.5)*	0.0 *(0.0)*	0.3 *(0.6)*	0.0 *(0.5)*	0.0 *(0.1)*
Cooling Towers	--	--	--	--	15.3 *(14.5)*
Total	214.6 *(169.4)*	16.2 *(14.0)*	188.8 *(598.9)*	62.1 *(48.1)*	104.2 *(142.2)*

* Previous values are shown in italics in parentheses
[a] Standby generator engines and firepump engine will not be tested on the same day.
[b] Detailed information regarding the PM_{10} emission rate for the gas turbines is included in Appendix 3.1-A4.

Tables 5.2-27 and 5.2-31 of the August 2001 AFC compared project emission levels with emissions-based significance thresholds. These tables have been revised to show the emissions associated with the proposed equipment changes. In these tables, the previous emission rates are shown in parentheses. As shown in Tables 3.1-4 and 3.1-5, there are no new significant impacts associated with the proposed equipment changes.

TABLE 3.1-4
Comparison of Net Emissions Increase with PSD Significant Emissions Levels, IEEC Project (Tons/Year)*

	NOx	SOx	CO	VOC	PM_{10}
New Equipment Emissions[a]	214.6 *(166.7)*	16.2 *(13.9)*	n.a.[b]	n.a.[b]	n.a.[b]
PSD Significance Levels[c]	40 (25)	40 (25)	n.a.[b]	n.a.[b]	n.a.[b]
PSD Review Required?	Yes	No	n.a.[b]	n.a.[b]	n.a.[b]

* Previous values are shown in italics in parentheses
[a] Emissions from gas turbines/HRSGs, auxiliary boiler, and standby/emergency engines.
[b] Because the project area is classified as a federal non-attainment area for these pollutants, PSD does not apply for these pollutants.
[c] Based on federal PSD regulations 40 CFR 52.21

TABLE 3.1-5
Comparison of Total Facility Emissions with SCAQMD Significance Levels, IEEC Project (lbs/day)*

	NOx	SOx	CO	VOC	PM_{10}
New Equipment Emissions[a]	2,566 *(1,495)*	96 *(81)*	1,395 *(8,339)*	353 *(350)*	592 *(727)*
SCAQMD Significance Levels	55	150	550	55	150
Significant according to SCAQMD levels?	Yes	No	Yes	Yes	Yes

* Previous values are shown in italics in parentheses
[a] Includes emissions from gas turbines, HRSGs, auxiliary boiler, standby/emergency engines, cooling towers.

3.1.2.2 Ambient Air Quality Impacts

Because the proposed equipment changes affect maximum hourly, daily, and annual emission levels and due to changes made to the facility layout, it was necessary to reevaluate the ambient air quality impacts for NO_2, CO, SO_2, and PM_{10}.

Regarding changes to the facility layout, while the gas turbine exhaust stack height remains at 195 feet, the proposed project changes include separate stacks for each gas turbine rather than the twin stack design analyzed in the August 2001 AFC. The stack height of the auxiliary boiler has increased to 100 feet. For the standby generator engines, the stack height has increased from 10 to 75 feet. The stack height of the emergency fire pump engine has increased from 10 to 15 feet. In addition to the change in gas turbine exhaust stack design and auxiliary equipment stack heights, the facility layout has been changed to accommodate two cooling towers (rather than the single tower analyzed in 2001) and new locations for the standby/emergency engines.

As with the original analysis performed for the August 2001 AFC, the assessment of impacts from the project on ambient air quality has been conducted using the ISCST and CTSCREEN models and the SCAQMD-approved meteorological data set collected at Riverside in 1981. To determine maximum 1-hour average NO_2 impacts for the new standby/emergency engines and the gas turbines during startups and during commissioning, the ISC_OLM model was used with concurrent hourly ozone data collected in Perris during 1999. The detailed modeling inputs for the analysis performed for the proposed equipment changes are enclosed as part of Appendix 3.1-A2. In addition, copies of the detailed electronic modeling input and output files are enclosed on a compact disk.

Tables 5.2-24, 5.2-26, 5.2-29, and 5.2-33 of the August 2001 AFC summarized the ambient air quality impacts for the project. These tables have been revised to show the ambient impacts associated with the proposed new equipment. While ambient impacts during gas turbine commissioning activities were evaluated in the August 2001 AFC, these impacts were reevaluated in early 2002 and summarized in a February 15, 2002 letter to the SCAQMD. These revised commissioning impacts for the GE S1074 System are shown in the following tables, with the previous impacts from the original proceeding shown in parentheses.

As shown in Tables 3.1-6 and 3.1-7, the modeled ambient impacts for the proposed new equipment are slightly higher or lower than previous impacts depending on the pollutant and averaging period. However, the overall ambient air quality impact conclusion for the project remains unchanged: the project will not cause or contribute to violations of any state or federal air quality standard, with the exception of the State of California PM_{10} and $PM_{2.5}$ standards where background levels already exceed these standards. In addition, as shown in Tables 3.1-8 and 3.1-9, the ambient impacts for the proposed equipment changes remain below the applicable SCAQMD and EPA significance thresholds, with the exception of the EPA PSD PM_{10} significance thresholds where both the existing and modified project impacts are above the thresholds. Consequently, there are no new significant ambient air quality impacts issues associated with the proposed equipment changes.

TABLE 3.1-6
Summary of Results from Refined Modeling Analyses Maximum Impacts, IEEC Project (σg/m^3)*

		Refined Modeling					
		Single Gas Turbine Only	**Both Gas Turbines Only**	**Entire Facility[a]**	**Fumigation[b]**	**Startup[c]**	**Commissioning[b]**
NO_2	1-hour	--	31.8[f] *(38.2)*	274.7[f,g] *(244.3)*	5.3 *(4.4)*	293.4[g] *(87.1)*	187.6[g] *(161.0)*
	Annual	--	0.8[d,e] *(0.5)*	0.8[d,e] *(0.5)*	--	--	--
SO_2	1-hour	--	3.1[f] *(3.0)*	58.1[f] *(30.1)*	0.5 *(0.4)*	0.0 *(2.9)*	--
	3-hour	--	2.8[f] *(2.6)*	22.6[f] *(2.7)*	0.5 *(0.3)*	0.0 *(2.6)*	--
	24-hour	--	0.9[f] *(0.6)*	2.4[f] *(0.9)*	--	--	--
	Annual	--	0.1[f] *(0.1)*	0.2[f] *(0.1)*	--	--	--
CO	1-hour	803.7 *(n.a.)*	29.1[f] (55.9)	379.7[f] *(325.7)*	4.8 *(6.5)*	117.7 *(792.8)*	814.7 *(389.0)*
	8-hour	466.9 *(n.a.)*	40.8[f] *(304.0)*	72.7[f] *(418.7)*	3.4 *(4.5)*	68.9 *(n.a.)*	473.8 *(n.a.)*
PM_{10}	24-hour	1.6[d] *(n.a.)*	6.3[f] *(2.48)*	9.1[f] *(9.9)*	--	--	--
	Annual	0.3[d] *(n.a.)*	0.9[f] *(0.5)*	1.3[f] *(1.4)*	--	--	--

* Previous values are shown in italics in parentheses
[a] Gas Turbines/HRSG, auxiliary boiler, standby/emergency engines, and cooling towers.
[b] Gas Turbines/HRSG.
[c] Gas Turbines/HRSG and auxiliary boiler.
[d] Based on CTSCREEN modeling results.
[e] ARM corrected using EPA correction factor of 0.75.
[f] Based on ISCST3 modeling results.
[g] OLM corrected.

TABLE 3.1-7
Modeled Maximum Project Impacts, IEEC Project*

Pollutant	Averaging Time	Maximum Project Impact[a] (μg/m³)	Background Concentrations[b] (μg/m³)	Total Impact (μg/m³)	State Standard (μg/m³)	Federal Standard (μg/m³)
NO_2	1-hour	293.4[f,g] *(244.3)*	171 *(211)*	464 *(455)*	470	--
	Annual	0.8 [d,e] *(0.5)*	34 *(36)*	35 *(37)*	--	100
SO_2	1-hour	58.1[f] *(30.1)*	50 *(278)*	108 *(308)*	650	--
	24-hour	2.4[f] *(0.9)*	31 *(92)*	33 *(93)*	109	365
	Annual	0.2[f] *(0.1)*	5 *(5)*	5 *(5)*	--	80
CO	1-hour	814.7[f] *(792.8)*	8,010 *(12,650)*	8,825 *(13,443)*	23,000	40,000
	8-hour	473.8[f] *(418.7)*	5,126 *(6,302)*	5,600 *(6,721)*	10,000	10,000
PM_{10}	24-hour	9.1[f] *(9.9)*	116 *(139)*	125 *(149)*	50	150
	Annual[c]	1.3[f] *(1.4)*	45 *(50)*	46 *(51)*	20	50
$PM_{2.5}$	24-hour	9.1[f] *(9.9)*	77 *(n.a.)*	86 *(n.a.)*	--	65
	Annual	1.3[f] *(1.4)*	30 *(n.a.)*	31 *(n.a.)*	12	15

* Previous values are shown in italics in parentheses
[a] Entire facility including gas turbines/HRSGs, auxiliary boiler, standby/emergency engines, cooling towers.
[b] Maximum background levels during past 3 years.
[c] Annual Arithmetic Mean (Federal).
[d] Modeled using CTSCREEN.
[e] ARM corrected using EPA correction factor of 0.75.
[f] Modeled using ISCST3.
[g] OLM corrected.

TABLE 3.1-8
Maximum Modeled Impacts and NSR/RECLAIM Significance Thresholds, IEEC Project (Maximum from a Single Gas Turbine/HRSG or Auxiliary Boiler)*

Pollutant	Averaging Time	Maximum Modeled Impacts (μg/m³)	NSR/RECLAIM Significance Threshold (μg/m³)	Significant Under NSR/RECLAIM?
CO	1-Hour	804 *(793)*	1,100	No
(NSR Pollutant)	8-Hour	467 *(419)*	500	No
PM_{10}	24-Hour	1.6[a] *(2.48)*	2.5	No
(NSR Pollutant)	Annual	0.3[a] *(0.5)*	1.0	No
SO_2 (NSR Pollutant)	1-Hour	n.a.	n.a.	n.a.
	8-Hour	n.a.	n.a.	n.a.
	Annual	n.a.	n.a.	n.a.
NO_2	1-Hr	n.a.	n.a.	n.a.
(RECLAIM Pollutant)	Annual	n.a.	n.a.	n.a.

* Previous values are shown in italics in parentheses
[A] MODELED USING CTSCREEN.

TABLE 3.1-9
Comparison of Maximum Modeled Impacts from ISCST3 and PSD Significance Thresholds and Class II Increments IEEC Project (Gas Turbines/ HRSGs, Auxiliary Boiler, Standby/Emergency Engines, and Cooling Towers)*

Pollutant	Averaging Time	Maximum Modeled Impacts, σg/m³	Federal PSD Significance Threshold, σg/m³	Federal PSD Class II Increment, σg/m³	Significant Under Federal PSD?
NO_2	Annual	0.8[a] *(0.5)*	1.0	25	No
SO_2	3-Hour	22.6[b] *(2.7)*	25	512	No
	24-Hour	2.4[b] *(0.9)*	5	91	No
	Annual	0.2[b] *(0.1)*	1.0	20	No

TABLE 3.1-9
Comparison of Maximum Modeled Impacts from ISCST3 and PSD Significance Thresholds and Class II Increments IEEC Project (Gas Turbines/ HRSGs, Auxiliary Boiler, Standby/Emergency Engines, and Cooling Towers)*

Pollutant	Averaging Time	Maximum Modeled Impacts, σg/m³	Federal PSD Significance Threshold, σg/m³	Federal PSD Class II Increment, σg/m³	Significant Under Federal PSD?
PM_{10}	24-Hour	9.1[b] *(9.9)*	5	30	Yes
	Annual	1.3[b] *(1.4)*	1.0	17	Yes
CO	1-Hour	815[b] *(793)*	2,000	-	No
	8-Hour	474[b] *(419)*	500	-	No

* Previous values are shown in italics in parentheses
[a] Based on CTSCREEN modeling results. Modeled annual NO_x corrected to NO_2 using ARM default value of 0.75.
[b] Based on ISCST3 modeling results.

3.1.2.3 Class I Impacts Analysis

In addition to analyzing the air quality impacts with respect to State and federal air quality standards, the August 2001 AFC evaluated the visibility impacts on nearby Class I areas. This evaluation included a regional haze and a coherent plume impact analysis. A supplemental Class I impact analysis was performed in December 2002 to respond to comments received from the Federal Land Managers (FLMs) during their review of the AFC. The Class I impact analysis has been revised to show the impacts associated with the proposed equipment changes. As with the previous analysis, the CALPUFF model was used for the revised regional haze analysis and the VISCREEN model was used for the revised coherent plume impact analysis. The revised Class I impacts are shown in the following tables, with the previous impacts shown in parenthesis. As shown in Tables 3.1-10 and 3.1-11, there are no new significant Class I impacts associated with the proposed equipment changes. A detailed discussion of the modeling is included as Appendix 3.1-A3.

TABLE 3.1-10
Class I Regional Haze Impacts, IEEC Project*

Class I Area	Percent Change in Extinction	Significance Level	Significant Impact?
Cucamonga Wilderness	3.95 *(3.68)*	5 *(5)*	*(no)*
Joshua Tree National Park	6.41 *(5.95)*	5 *(5)*	*(no[a])*
San Gabriel Wilderness	2.84 *(2.65)*	5 *(5)*	*(no)*

* Previous values are shown in italics in parentheses
[a] For the previous Class I analysis performed for the project in December 2002, the FLMs determined that the impacts were not significant because the exceedance of the 5% significance level occurred during only two days over a three-year period. A similar conclusion can be made for the impacts associated with the proposed IEEC equipment changes with exceedance of the 5% significance level during only four days over a three-year period.

TABLE 3.1-11
Class I Coherent Plume Impacts, IEEC Project*

		Delta-E		Contrast	
Background	Theta	Model Impact	Significance Level	Model Impact	Significance Level
Aqua Tibia Wilderness					
Sky	10	0.808 *(1.021)*	*2*	-0.016 *(0.019)*	0.05

TABLE 3.1-11
Class I Coherent Plume Impacts, IEEC Project*

Background	Theta	Delta-E Model Impact	Delta-E Significance Level	Contrast Model Impact	Contrast Significance Level
Sky	140	1.301 *(1.126)*	2	-0.032 *(0.027)*	0.05
Terrain	10	1.717 *(1.334)*	2	0.012 *(0.009)*	0.05
Terrain	140	0.423 *(0.406)*	2	0.004 *(0.005)*	0.05
San Jacinto Wilderness					
Sky	10	0.602 *(0.533)*	*2*	-0.012 *(0.011)*	0.05
Sky	140	0.971 *(0.980)*	2	-0.024 *(0.023)*	0.05
Terrain	10	1.289 *(1.360)*	2	0.011 *(0.011)*	0.05
Terrain	140	0.350 *(0.364)*	2	0.004 *(0.004)*	0.05
San Gorgonio Wilderness					
Sky	10	0.515 *(0.455)*	*2*	-0.011 *(0.009)*	0.05
Sky	140	0.870 *(0.879)*	2	-0.021 *(0.020)*	0.05
Terrain	10	1.205 *(1.271)*	2	0.010 *(0.011)*	0.05
Terrain	140	0.333 *(0.346)*	2	0.004 *(0.004)*	0.05

* Previous values are shown in italics in parentheses

3.1.3 Mitigation Measures

One of the primary forms of mitigation for the project is the use of emission offsets. The emission offsets for the project consist of NOx RECLAIM Trading Credits (RTCs) and CO, VOC, SOx, and PM_{10} Emission Reduction Credits (ERCs). Table 5.2-32 of the August 2001 AFC summarized the emission offsets required for the project. During the latter stages of the permitting process, the offset requirements for the project were finalized, as described in the April 2003 addendum to the FDOC. In the following table the emission offset requirements for the proposed equipment changes are compared to the previous offset requirements. The previous emission offsets requirements are shown in parentheses. As shown in Table 3.1-12, the emission offset requirements for the proposed equipment changes are either equal to or less than the amounts required previously, with the exception of SOx offsets. The amount of SOx offsets for the proposed equipment changes will increase by approximately 11 lbs/day from the previous level of 81 lbs/day. However, this amount of additional SOx offsets is readily available from the SCAQMD Priority Reserve. Consequently, there are no new significant emission offset issues associated with the proposed equipment changes.

TABLE 3.1-12
Summary of ERC/RTC Requirements, IEEC Project*

Unit	NOx (lbs/yr)	CO (lbs/day)	SOx (lbs/day)	VOC (lbs/day)	PM_{10} (lbs/day)
Offset Type	RTC[a]	ERC	ERC	ERC	ERC

TABLE 3.1-12
Summary of ERC/RTC Requirements, IEEC Project*

Unit	NOx (lbs/yr)	CO (lbs/day)	SOx (lbs/day)	VOC (lbs/day)	PM_{10} (lbs/day)
Net Increase from Gas Turbines/HRSGs and Auxiliary Boiler	322,967 *(490,593)*	685 *(686)*	92 *(81)*	256 *(283)*	503 *(504)*
Offset Ratio	1.0:1	1.2:1	1.0:1	1.2:1	1.0:1
Offsets Required	322,967 *(490,593)*	823 *(823)*	92 *(81)*	307 *(340)*	503 *(504)*

* Previous values are shown in italics and parentheses
[a] This represents the maximum expected annual NOx RTC requirement for the project during the first year of operation, which includes the commissioning period. During a normal operating year, the maximum expected NOx RTCs associated with the proposed equipment changes would be slightly higher than this level (approximately 323,023 lbs).

Other than the slight increase in SOx emission offsets discussed above, there are no new mitigation measures being proposed for the equipment changes. With regards to mitigation measure requirements, the existing Conditions of Certification will mitigate any potential impacts below the level of significance.

3.1.4 Consistency with LORS

The proposed equipment changes have no effect on the project’s compliance with air quality LORs as analyzed in the August 2001 AFC, and the project will remain consistent with these LORs. In addition, the proposed equipment changes will not alter the conclusions made in the Commission Decision for this project (01-AFC-17). A revised SCAQMD Final Determination of Compliance (FDOC) will be required for the proposed equipment changes. An application package for this revised FDOC was submitted to the SCAQMD on (February 2, 2005) and a copy of this document was submitted to the CEC. The SCAQMD permit engineer responsible for reviewing/processing this application is Mr. Li Chen (909-396-2426). The Air Quality Conditions of Certification will need to be modified to allow for the proposed equipment changes and also to remain consistent with the revised SCAQMD FDOC language. The proposed changes to the air quality Conditions of Certification are included at the end of this section.

3.1.5 References Cited

Calpine Corporation. February 2002. Permit Applications for the Inland Empire Energy Center Project (Facility I.D. 129816). Letter dated February 15, 2002 from Michael A. Hatfield with Calpine to John Yee with South Coast AQMD.

Calpine Corporation. August 2002. Preliminary Determination of Compliance for the Inland Empire Energy Center project (Facility I.D. 129816). Letter dated August 22, 2002 from Michael A. Hatfield with Calpine to John Yee with South Coast AQMD.

SCAQMD. April 2003. Addendum to the Final Determination of Compliance (FDOC), Inland Empire Energy Center (IEEC), 01-AFC-017. Letter dated April 25, 2003 from Pang Mueller with SCAQMD to Jim Bartridge with CEC.

Sierra Research, Inc. December 2002. Supplemental Class I Impact Analysis. Letter dated December 18, 2002 from Gary Rubenstein with Sierra Research to John Yee with the South Coast AQMD.

3.1.6 Conditions of Certification

The following changes to conditions of certification are necessary for this Amendment.

Staff Conditions – Construction

AQ-SC9 The project owner shall provide emission reduction credits to offset turbine, ~~duct burner~~, auxiliary boiler, and standby/emergency equipment NOx, CO, VOC, SOx, and PM_{10} 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** and **AQ-46**. Emission reduction credits (ERCs) shall be provided for CO (823 lb/day, includes offset ratio of 1.2) and VOC (~~340~~ 307 lb/day, includes offset ratio of 1.2). Emission reduction credits for SOx (~~81~~ 92 lb/day) and PM_{10} (~~504~~ 503 lb/day) shall be obtained from the SCAQMD Priority Reserve.

The project owner shall surrender the ERCs for CO and VOC from among those that are listed in the table below or a modified list, as allowed by this condition. If additional ERCs are submitted, the project owner shall submit an updated table including the additional ERCs to the CPM. The project owner shall request CPM approval for any substitutions, modifications, or additions of credits listed.

Prior to commencement of construction, the project owner shall obtain sufficient RTCs to satisfy the District's requirements for the first year of operation.

The CPM, in consultation with the District, may approve any such change to the ERC list provided that the project remains in compliance with all applicable laws, ordinances, regulations, and standards, the requested change(s) will not cause the project to result in a significant environmental impact, and the District confirms that each requested change is consistent with applicable federal and state laws and regulations. The CPM may also consult the U.S. EPA to determine compliance of credits.

Pollutant	**Quantity**	**(units)**	**ERC# or Offset Strategy**
~~NOx~~	~~38,234~~	~~lb~~	~~2005-2010, Coastal, Zone 1~~
NOx	~~452,359~~ 322,967	lb	2006-2010+, Coastal Zone 1, ~~Coastal~~ Inland Zone 2 ~~(as listed in Ex. 2, p. 5.1-54.)~~
CO	677	lb/day	#AQ003178
CO	144	lb/day	#AQ004233
CO	3	lb/day	#AQ004222
CO	2	lb/day	#AQ004417
VOC	~~340~~ 307	lb/day	#AQ003069
PM10	~~504~~ 503	lb/day	Through Priority Reserve.
SOx	~~81~~ 92	lb/day	Through Priority Reserve.

Verification: 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 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.

AQ-SC11 The project owner shall perform quarterly cooling tower recirculating water quality testing, 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.

Verification: 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**).

AQ-SC12 The cooling tower daily PM_{10} emissions shall be limited to ~~79~~ 42 lb/day per cooling tower. The cooling towers shall be equipped with ~~a~~ drift eliminators to control the drift fraction to 0.0005 percent of the circulating water flow. The project owner shall estimate daily PM_{10} emissions from the cooling towers using the water quality testing data or continuous monitoring data and daily circulating water flow data collected on a quarterly basis.

Verification: The project owner shall submit to the CPM daily cooling tower PM_{10} emission estimates in the Quarterly Operation Report (**AQ-SC8**).

AQ-SC13 The project owner shall minimize emissions of carbon monoxide and nitrogen oxides from the gas turbines ~~and duct burners~~ to the maximum extent possible during the commissioning period. ~~Commissioning tests for one gas turbine shall not be conducted simultaneously with commissioning tests for the other.~~

Verification: See the verification for Condition **AQ-17**.

~~**AQ-SC14** The project owner shall limit emissions during startup periods so that startup of a gas turbine shall only occur when the other turbine is not in a startup mode.~~

~~**Verification:** See the verification for Condition **AQ-17**.~~

AQ-SC15 The gas turbines ~~and duct burners~~ shall be fired on natural gas that results in emissions of less than 1.83 lb/hr SOx for each gas turbine ~~and duct burner pair~~, averaged over three hours.

Verification: The project owner shall compile hourly SOx emissions data for each gas turbine ~~and duct burner pair~~. 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**).

DISTRICT CONDITIONS – DETERMINATION OF COMPLIANCE
Gas Turbines, Duct Burners, and SCR

AQ-8 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
NO_x emissions	District Method 100.1	1 hour	~~Outlet~~ Downstream of the SCR
CO EMISSIONS	District Method 100.1	1 hour	~~Outlet~~ Downstream of the SCR
SO_x emissions	Approved District Method	District Approved Averaging Time	Fuel Sample
~~ROG~~ VOC emissions	Approved District Method	1 HOUR	~~Outlet~~ Downstream of the SCR
PM emissions	Approved District Method	District Approved Averaging Time	~~Outlet~~ Downstream of the SCR
NH_3 emissions	District Method 207.1 and 5.3 or EPA Method 17	1 hour	~~Outlet~~ Downstream of the SCR

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 ~~turbine and steam turbine~~ generating output in MW.

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.

The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit. For natural gas fired turbines only, this shall be demonstrated by 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 method does not mean that it is more accurate than AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD method 25.3 without prior approval, except 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 ~~with and without duct firing~~ when this equipment is operating at loads of 100, 75, and 50 percent of maximum load for the NO_x, CO, ~~ROG~~ VOC and ammonia tests. For all other pollutants, the test shall be conducted ~~with and without duct firing~~ at 100% load only. (SCAQMD 29-1)

Verification: 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.

AQ-9 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
SO_x emissions	Approved District Method	District Approved Averaging Time	Fuel Sample
~~ROG~~ VOC emissions	Approved District Method	1 HOUR	~~Outlet~~ Downstream of the SCR
PM emissions	Approved District Method	District Approved Averaging Time	~~Outlet~~ Downstream of the SCR

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 1) when the gas turbine ~~and the duct burners are~~ is operating ~~simultaneously~~ at 100 percent of maximum heat input ~~and 2) when the gas turbine is operating alone at 100 percent of maximum heat input~~.

The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit. For natural gas fired turbines only, this shall be demonstrated by 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 method does not mean that it is more accurate than AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD method 25.3 without prior approval, except 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 29-2)

Verification: 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.

AQ-10 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
NH_3 emissions	District Method 207.1 and 5.3 or EPA Method 17	1 hour	~~Outlet~~ Downstream 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 after the initial source test 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 29-3)

Verification: 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.

AQ-11 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 (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 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 40-1)

Verification: See verifications for Conditions **AQ-8**, **AQ-9**, and **AQ-10**.

AQ-12 The operator shall not use natural gas containing the following specified compounds:

Compound	**Grains per 100 scf**
H2S	Greater than 0.25

This concentration limit is an annual average based on monthly sample of natural gas composition or gas supplier documentation. (SCAQMD 61-1)

Verification: 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**).

AQ-13 The operator shall limit emissions from this equipment as follows:

Contaminant	**Emissions Limit**
CO	~~9,960~~ 9,723 LBS IN ANY 1 MONTH
PM_{10}	7,440 LBS IN ANY 1 MONTH
~~ROG~~ VOC	~~4,188~~ 3,773 LBS IN ANY 1 MONTH
SO_x	~~1,197~~ 1,362 LBS IN ANY 1 MONTH

For the purpose of this condition, the limits shall be based on the ~~combined~~ emissions from each gas turbine ~~and its associated duct burners~~.

The operator shall calculate the emissions by using monthly fuel use data and the following emission factors: PM_{10} ~~with duct burners firing~~ ~~4.23~~ 3.91 lbs/mmscf, ~~PM_{10} without duct burners firing 5.01 lbs/mmscf~~, ~~ROG~~ VOC ~~with duct burners firing~~ ~~2.55~~ 1.80 lbs/mmscf, ~~ROG without duct burners firing 1.41 lbs/mmscf~~, SO_x 0.71 lbs/mmscf ~~with and without duct burner firing~~.

The operator shall calculate the emissions for CO, during the commissioning period, using fuel consumption data and the following emission factor: ~~127.87~~ 22.19 lb/mmscf.

The operator shall calculate the emissions for CO, after the commissioning period and prior to the CO CEMS certification, using fuel consumption data and the following emission factor: ~~19.76~~ 4.65 lbs/mmscf.

The operator shall calculate the emissions 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 63-1)

Verification: 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**).

AQ-17 The 2.0 ppm NO_x emission limit(s) shall not apply during turbine commissioning, startup, and shutdown periods. Startup/shutdown time shall not exceed four hours per day per gas turbine except for a cold startup or combustor tuning activities, which shall not exceed 6 hours per day per gas turbine. For purposes of this condition a cold startup shall be defined as a startup of the gas turbine after 72 hours of non-operation. The commissioning period per gas turbine shall not exceed 636 operating hours during the first 180 calendar days from the date of initial start-up. The gas turbine operating hours during the commissioning period need not be consecutive. The operator shall provide the AQMD with written notification of the start-up date. Written records of commissioning, startups, and shutdowns shall be maintained and made available upon request from AQMD. (SCAQMD 99-1)

Verification: 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 provide start-up and shutdown occurrence and duration data as part as part of the Quarterly Operation Report (**AQ-SC8**). The project owner shall make the site available for inspection of the commissioning and start-up/shutdown records by representatives of the District, CARB and the Commission.

AQ-18 The 3.0 ppm CO emission limit(s) shall not apply during turbine commissioning, startup, and shutdown periods. Startup/shutdown time shall not exceed four hours per day per gas turbine, except for a cold startup or combustor tuning activities, which shall not exceed 6 hours per day per gas turbine. For purposes of this condition a cold startup shall be defined as a startup of the gas turbine after 72 hours of non-operation. The commissioning period per gas turbine shall not exceed 636 operating hours during the first 180 calendar days from the date of initial start-up. The gas turbine operating hours during the commissioning period need not be consecutive. The operator shall provide the AQMD with written notification of the initial start-up date. Written records of commissioning, startups, and shutdowns shall be maintained and made available upon request from AQMD. (SCAQMD 99-2)

Verification: See verification of Condition **AQ-17**.

AQ-19 The ~~14.03~~ 9.69 lbs/mmscf NO_x emission limit(s) shall only apply during the interim period to report RECLAIM emissions. The interim period shall not exceed 12 months from the initial startup date. (SCAQMD 99-3)

Verification: 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**).

AQ-22 The 2.0 ppmv NO_x emission limit is averaged over 1 hour at 15 percent oxygen, dry basis. 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 ~~a fogging system injection pump~~ inlet air chilling

~~c) The first two 1-hour reporting periods following the initiation/shutdown of combustion turbine steam injection~~

~~d) The first two 1-hour reporting periods following the initiation of HRSG duct burners~~

~~e~~c) 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~~ 15 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 195-1)

Verification: 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**).

AQ-23 The 3.0 ppmv CO emission limit is averaged over 1 hour at 15 percent oxygen, dry basis ~~when the HRSG duct burners are not operating~~. ~~The 4.0 ppmv CO emission limit is averaged over 1 hour at 15 percent oxygen, dry basis when the HRSG duct burners are operating.~~ (SCAQMD 195-2)

Verification: 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**).

AQ-24 The 2.0 ppmv ~~ROG~~ VOC emission limit is averaged over 1 hour at 15 percent oxygen, dry basis. (SCAQMD 195-3)

Verification: See verifications for Conditions **AQ-8** and **AQ-9**.

AQ-25 The 5 ppmv NH_3 emissions limit is averaged over 1 hour at 15 percent oxygen, dry basis. (SCAQMD 195-6)

Verification: See verification for Conditions **AQ-8**, **AQ-10**, and **AQ-26**.

AQ-26 ~~The operator shall install, operate, and maintain an approved Continuous Emission Monitoring Device, approved by the Executive Officer, to monitor and record ammonia concentrations, and alert the operator (via audible or visible alarm) whenever ammonia concentrations are near, at, or in excess of the permitted ammonia limit of 5 ppmv, corrected to 15% oxygen. It shall continuously monitor or calculate, and record the following parameters:~~

- ~~Ammonia concentration, uncorrected in ppmv~~
- ~~Oxygen concentration in percent~~
- ~~Ammonia concentration in ppmv, corrected to 15% oxygen~~
- ~~Date, time, extent (in time) of all excursions above 5 ppmv, corrected to 15% oxygen~~

~~The Continuous Emission Monitoring Device described above shall be operated and maintained according to a Quality Assurance Plan (QAP) approved by the Executive Officer. The QAP must address contingencies for monitored ammonia concentrations near, at, or above the permitted compliance limit, and remedial actions to reduce ammonia levels once an exceedance has occurred.~~

~~The Continuous Emission Monitoring Device may not be used for compliance determination or emission information determination without corroborative data using an approved reference method for the determination of ammonia.~~

~~The Continuous Emission Monitoring Device shall be installed and operating no later than 90 days after initial startup of the turbine.~~

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/lbmol), b= dry exhaust flow rate (scf/hr)/(385.5 scf/lbmol), 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.
(SCAQMD 232-1)

Verification: ~~The project owner shall provide the CPM documentation of the District's approval of the continuous emission monitoring device, within 15 days of its receipt~~. The project owner shall make the site available for inspection of the ~~monitoring device and monitoring device~~ calculation method records by representatives of the District, CARB and the Commission. The project owner shall submit to the CPM emissions data generated by the ~~continuous emission monitoring device~~ calculation method as part of the Quarterly Operation Report (**AQ-SC8**).

AQ-TBD The operator shall comply with the 2.0 ppmvd @ 15% O2 NOx BACT emission concentration limit at all times, except as specified in Conditions AQ-17 and AQ-22 and under the following conditions:

Emission Limit	Averaging Time	Operation Requirement
408 lbs/hr	3 Hours	This emission limit shall apply to a single gas turbine during startups and combustor tuning activities.

Verification: 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**).

AQ-32 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**
NO_x emissions	District Method 100.1	1 hour	~~Outlet~~ Downstream of the SCR
CO EMISSIONS	District Method 100.1	1 hour	~~Outlet~~ Downstream of the SCR
SO_x emissions	Approved District Method	District Approved Averaging Time	Fuel Sample
~~ROG~~ VOC emissions	Approved District Method	1 HOUR	~~Outlet~~ Downstream of the SCR

PM emissions	Approved District Method	District Approved Averaging Time	~~Outlet~~ Downstream of the SCR
NH_3 emissions	District Method 207.1 and 5.3 or EPA Method 17	1 hour	~~Outlet~~ Downstream of the SCR

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.

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 loads of 100, 75, and 50 percent of maximum load for the NOx, CO, ~~ROG~~ VOC and ammonia tests. For all other pollutants, the test shall be conducted at 100% load only. (SCAQMD 29-1).

Verification: 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.

AQ-33 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**
NH_3 emissions	District Method 207.1 and 5.3 or EPA Method 17	1 hour	~~Outlet~~ Downstream 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 after the initial source test and at least annually thereafter. The NO_x 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 NO_x 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 29-3)

Verification: 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.

AQ-36 The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
CO	~~667~~ 1117 LBS IN ANY 1 MONTH
PM_{10}	~~233~~ 218 LBS IN ANY 1 MONTH
~~ROG~~ VOC	~~127~~ 128 LBS IN ANY 1 MONTH
SO_x	~~19~~ 22 LBS IN ANY 1 MONTH

The operator shall calculate the emissions by using monthly fuel use data and the following emission factors: CO ~~21.72~~ 37.10 lb/mmscf, PM_{10} ~~7.58~~ 7.26 lbs/mmscf, ~~ROG~~ VOC ~~4.14~~ 4.25 lbs/mmscf, SO_x ~~0.70~~ 0.71 lbs/mmscf.

The operator shall calculate the emissions 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 63-2)

Verification: 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**).

AQ-39 The ~~8.36~~ 8.53 lbs/mmscf NO_x emission limit(s) shall only apply during the interim reporting period to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from the initial startup date. (SCAQMD 99-4)

Verification: 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**).

Verification: See verification for Conditions **AQ-32**, **AQ-33**, and **AQ-45**.

AQ-45 ~~The operator shall install, operate, and maintain an approved Continuous Emission Monitoring Device, approved by the Executive Officer, to monitor and record ammonia concentrations, and alert the operator (via audible or visible alarm) whenever ammonia concentrations are near, at, or in excess of the permitted ammonia limit of 5 ppmv, corrected to 3% oxygen. It shall continuously monitor or calculate, and record the following parameters:~~

- ~~Ammonia concentration, uncorrected in ppmv~~
- ~~Oxygen concentration in percent~~

- ~~Ammonia concentration in ppmv, corrected to 3 percent oxygen~~

- ~~Date, time, extent (in time) of all excursions above 5 ppmv, corrected to 3 percent oxygen~~

- ~~The Continuous Emission Monitoring Device described above shall be operated and maintained according to a Quality Assurance Plan (QAP) approved by the Executive Officer. The QAP must address contingencies for monitored ammonia concentrations near, at, or above the permitted compliance limit, and remedial actions to reduce ammonia levels once an exceedance has occurred.~~

- ~~The Continuous Emission Monitoring Device may not be used for compliance determination or emission information determination without corroborative data using an approved reference method for the determination of ammonia.~~

~~The Continuous Emission Monitoring Device shall be installed and operating no later than 90 days after initial startup of the boiler.~~
<u>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/lbmol), b= dry exhaust flow rate (scf/hr)/(385.5 scf/lbmol), 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.</u>
(SCAQMD 232-2)

<u>**Verification:**</u> ~~The project owner shall provide the CPM documentation of the District's approval of the continuous emission monitoring device, within 15 days of its receipt.~~ The project owner shall make the site available for inspection of the ~~monitoring device and monitoring device~~ <u>calculation method</u> records by representatives of the District, CARB and the Commission. The project owner shall submit to the CPM emissions data generated by the ~~continuous emission monitoring device~~ <u>calculation method</u> as part of the Quarterly Operation Report (**AQ-SC8**).

~~Emergency~~ <u>Standby</u> Generator and <u>Emergency</u> Fire Pump Engine<u>s</u>

<u>Conditions of Certification AQ-47 through AQ-50 apply separately to the ~~emergency~~ standby generator and fire pump engines, unless otherwise specified</u>.

AQ-47 The operator shall limit the operating time of the engine to no more than ~~200~~ <u>50</u> hours per year <u>per device</u>. (SCAQMD 1-1)

Verification: The project owner shall submit to the CPM and APCO the ~~emergency~~ standby generator and emergency fire pump IC engines operations data demonstrating compliance with this condition as part of the Quarterly Operation Report (**AQ-SC8**).

AQ-48 The operator shall install and maintain a non-resetable elapsed time meter to accurately indicate the elapsed operating time of the engine. (SCAQMD 12-4)

Verification: The project owner shall make the ~~emergency~~ standby generator and emergency fire pump engines available for inspection by representatives of the District, CARB and the Commission upon request.

AQ-49 The operator shall install and maintain a non-resetable elapsed fuel meter to accurately indicate the engine fuel consumption. (SCAQMD 12-5)

Verification: The project owner shall make the ~~emergency~~ standby generator and emergency fire pump engines available for inspection by representatives of the District, CARB and the Commission upon request.

AQ-50 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.
- Records shall be kept and maintained on file for a minimum of two years and made available to district personnel upon request. (SCAQMD 67-2)

Verification: The project owner shall make the ~~emergency~~ standby generator and emergency fire pump engines records available for inspection by representatives of the District, CARB and the Commission upon request.

Ammonia Storage Tanks

AQ-52 The operator shall install and maintain a pressure relief valve set at 25 psig or higher. (SCAQMD 157-1)

Verification: 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.

Attachment Air Quality 1 – AQ-SC16, Equipment Description

[Following is a copy of Equipment Description from Addendum to Final Determination of Compliance, filed by SCAQMD, dated April 25, 2003.]

EQUIPMENT DESCRIPTION

Section H of the facility permit: Permit to Construct and temporary Permit to Operate

PROCESS 1: COMBUSTION AND POWER GENERATION **SYSTEM 1: GAS TURBINE COMBUSTION**					
Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
TURBINE, #1, NATURAL GAS, GENERAL ELECTRIC, MODEL ~~7251FB~~ S107H (H System) COMBINED CYCLE, WITH DRY LOW NOx BURNERS, FUEL MOISTURIZATION, ~~WITH STEAM INJECTION~~, ~~1,813~~ 2,597 MMBtu/HR. WITH A/N 391432 GENERATOR #1, ~~174~~ 405 MW GENERATOR, #1, HEAT RECOVERY STEAM GENERATOR (HRSG) ~~STEAM TURBINE GENERATOR, 322 MW~~ ~~COMMON WITH HRSG #2~~	D1 B11 B13 ~~B15~~	C17	NOx: MAJOR SOURCE	**NOx**: 2.0 PPMV (4) [RULE 2005 BACT]; NOx: ~~98.3~~ 111.0 PPMV NATURAL GAS (8) [40CFR 60 SUBPART GG]; NOx (INTERIM): ~~14.03~~ 9.69 LBS/MMSCF (1) [RULE 2012]; **CO**: 3.0 PPMV (4) [RULE 1303 BACT]; ~~CO: 4.0 PPMV [RULE 1303 BACT~~]; CO: 2,000 PPMV (5) [RULE 407]; ~~**ROG**~~ **VOC**: 2.0 PPMV (4) [RULE 1303-BACT]; **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; or PM: 0.01 GR/SCF (5A) [RULE 475]; **SOx**: 150 PPMV (8) [40CFR 60 SUBPART GG]; SO2: (9) [40CFR 72 – ACID RAIN]; H2S LEVEL IN NATURAL GAS LESS THAN 0.25 GRAIN PER 100 SCF [RULE 1303-OFFSET]	29-1, 29-2, 40-1, 61-1, 63-1, 67-1, 82-1, 82-2, 99-1, 99-2, 99-3, 193-1, 195-1, 195-2, 195-3, 296-1, 327-1
PROCESS 1: COMBUSTION AND POWER GENERATION **SYSTEM 1: GAS TURBINE COMBUSTION**					

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
~~BURNER, DUCT, NATURAL GAS, 697 MMBtu/HR, LOCATED IN THE HRSG OF TURBINE #1~~ ~~WITH A/N 391432~~	~~D14~~	~~C17~~	~~NOx: MAJOR SOURCE~~	~~**NOx**: 2.0 PPMV (4) [RULE 2005 BACT]; NOx: 0.2 LB/ MMBtu NATURAL GAS (8) [40CFR 60 SUBPART DA]; NOx(INTERIM): 14.03 LBS/MMSCF (1) [RULE 2012];~~ ~~**CO**: 4.0 PPMV (4) [RULE 1303 BACT]; CO: 2,000 PPMV (5) [RULE 407];~~ ~~**ROG**: 2.0 PPMV (4) [RULE 1303-BACT];~~ ~~**PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475];~~ ~~**SOx**: 0.2 LB/MMBtu (8) [40CFR 60 SUBPART DA]; SO2: (9) [40CFR 72 – ACID RAIN]; H2S LEVEL IN NATURAL GAS LESS THAN 0.25 GRAIN PER 100 SCF [RULE 1303-OFFSET]~~	~~29-1, 29-2, 40-1, 61-1, 63-1, 67-1, 82-1, 82-2, 99-1, 99-2, 99-3, 193-1, 195-1, 195-2, 195-3, 296-1, 327-1~~
CO OXIDATION CATALYST #1, SERVING TURBINE/HRSG #1 A/N 391423	C17	C4, D1, ~~D14~~			
SELECTIVE CATALYTIC REDUCTION, #1, SERVING TURBINE/HRSG #1 WITH AMMONIA INJECTION, INJECTION GRID A/N:391423	C4 B18	C17		NH3: 5 PPMV (4) [RULE 1303(a)(1)-BACT]	12-1, 12-2, 12-3, 29-3, 179-1,179-2, 195-6, 232-1

STACK, #1 SERVING TURBINE AND HRSG #1, 195' HEIGHT X ~~18'6"~~ 22' DIAMETER A/N: 391432	S19	C4			
PROCESS 1: COMBUSTION AND POWER GENERATION **SYSTEM 1: GAS TURBINE COMBUSTION**					
Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
TURBINE, #2, NATURAL GAS, GENERAL ELECTRIC, MODEL ~~7251FB~~ S107H (H SYSTEM), COMBINED CYCLE, WITH DRY LOW NOx BURNERS, FUEL MOISTURIZATION ~~WITH STEAM INJECTION~~, ~~1,813~~ 2,597 MMBtu/HR. WITH A/N: 391424 GENERATOR, #2, ~~SERVICE TURBINE #2~~, ~~174~~ 405 MW GENERATOR, #2, HEAT RECOVERY STEAM GENERATOR (HRSG) ~~STEAM TURBINE GENERATOR, 322 MW, COMMON WITH HRSG #1~~	D2 ~~B12~~ B20 B22 ~~B15~~	C18	NOx MAJOR SOURCE	**NOx**: 2.0 PPMV (4) [RULE 2005]; NOx ~~98.3~~ 111.0 PPMV (8) [40CFR 60 SUBPART GG]; NOx(INTERIM): ~~14.03~~ 9.69 LBS/ MMSCF (1) [RULE 2012]; **CO**: 3.0 PPMV (4) [RULE 1303 BACT]; ~~CO: 4.0 PPMV [RULE 1303 BACT]~~; CO: 2,000 PPMV (5) [RULE 407]; **~~ROG~~ VOC**: 2.0 PPMV (4) [RULE 1303-BACT]; **PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; or PM: 0.01 GR/SCF (5A) [RULE 475]; **SOx**: 150 PPMV (8) [40CFR 60 SUBPART GG] SO2: (9) [40CFR 72 – ACID RAIN]; H2S LEVEL IN NATURAL GAS LESS THAN 0.25 GR PER 100 SCF [RULE 1303-OFFSET]	29-1, 29-2, 40-1, 61-1, 63-1, 67-1, 82-1, 82-2, 99-1, 99-2, 99-3, 193-1, 195-1, 195-2, 195-3, 296-1, 327-1
~~BURNER, DUCT, NATURAL GAS, 697 MMBtu/HR, LOCATED IN THE HRSG OF~~	~~D21~~	~~C18~~	~~NOx: MAJOR SOURCE~~	~~**NOx**: 2.0 PPMV (4) [RULE 2005 BACT]; NOx: 0.2 LB/ MMBtu NATURAL GAS~~	~~29-1, 29-2, 40-1, 61-1, 63-~~

~~TURBINE #2~~ ~~A/N 391424~~				~~(8) [40CFR 60 SUBPART DA]; NOx(INTERIM): 14.03 LBS/ MMSCF (1) [RULE 2012];~~ ~~**CO**: 4.0 PPMV (4) [RULE 1303 BACT]; CO: 2,000 PPMV (5) [RULE 407];~~ ~~**ROG**: 2.0 PPMV (4) [RULE 1303-BACT];~~ ~~**PM**: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475];~~	~~1, 67-1, 82-1, 82-2, 99-1, 99-2, 99-3, 193-1, 195-1, 195-2, 195-3, 296-1, 327-1~~
PROCESS 1: COMBUSTION AND POWER GENERATION **SYSTEM 1: GAS TURBINE COMBUSTION**					
Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
				~~**SOx**: 0.2 LB/MMBtu (8) [40CFR 60 SUBPART DA]; SO_2: (9) [40CFR 72 – ACID RAIN]; H2S LEVEL IN NATURAL GAS LESS THAN 0.25 GR PER 100 SCF [RULE 1303-OFFSET]~~	
CO OXIDATION CATALYST #2, SERVING TURBINE/HRSG #2 A/N 391424	C18	D2, ~~D21~~, C5			
SELECTIVE CATALYTIC REDUCTION, #2, SERVING TURBINE/HRSG #2, WITH	C5	C18		**NH3**: 5 PPMV (4) [RULE 1303-BACT]	12-1, 12-2, 12-3, 29-3, 179-

A/N:391425 WITH AMMONIA INJECTION, INJECTION GRID	B25				1, 179-2, 195-6, 232-1
STACK, #2, SERVING TURBINE AND HRSG #2, HEIGHT: 195'0", DIAMETER: ~~18'6"~~ 22' A/N: 391425	S26	C5			
PROCESS 1: COMBUSTION AND POWER GENERATION **SYSTEM 2: AUXILIARY EQUIPMENT**					
BOILER, AUXILIARY, NATURAL GAS FIRED, ~~129~~ 157 MMBtu/HR A/N 391426 BURNER, NATURAL GAS, TBD	D3	~~C27~~ C6	NOx MAJOR SOURCE	**NOx**: 7.0 PPMV (4) [RULE 2005 BACT]; NOx: ~~8.36~~ 8.53 LBS/ MMSCF (1) [RULE 2012]; **CO**: 50 PPMV (4) [RULE 1303 BACT]; CO: 2,000 PPMV (5) [RULE 407]; **PM**: 0.1 GR/SCF (5) [RULE 409];	29-4, 40-2, 61-1, 63-2, 82-3, 82-4, 99-4, 193-1, 195-4, 195-5, 296-1
~~CO OXIDATION CATALYST #3, SERVING AUXILIARY BOILER,~~ ~~A/N 391427~~	~~C27~~	~~D3, C6~~			
PROCESS 1: COMBUSTION AND POWER GENERATION **SYSTEM 2: AUXILIARY EQUIPMENT**					
Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
SELECTIVE CATALYTIC	C6	~~C27~~ D3		**NH3**: 5 PPMV (4) [RULE	12-1, 12-

REDUCTION, #3, SERVING AUXILIARY BOILER WITH A/N:391427 WITH AMMONIA INJECTION, INJECTION GRID	B25			1303-BACT]	2, 12-3, 29-3, 179-1, 179-2, 195-7, 232-2
~~EMERGENCY~~ STANDBY GENERATOR #1, ~~NATURAL GAS~~ DIESEL, IC ENGINE, CATERPILLAR, MODEL ~~G3516LE~~ 3516BDITA, ~~1467~~ 2,848 HP A/N 391430	D9		NOx: PROCES S UNIT	**NOx**: ~~1.5~~ 6.65 GM/BHP-HR (4) [RULE 2005]; NOx: ~~380 LB/MMSCF~~ 290 LBS/1000 GAL(1) [RULE 2012]; **CO**: ~~2.0~~ 1.01 GM/BHP-HR (4) [RULE 1303]; ~~ROG~~ **VOC**: ~~1.5~~ 0.14 GM/BHP-HR (4) [RULE 1303];	1-1, 12-4, 12-5, 67-2,193-1, 296-1
STANDBY GENERATOR #2, DIESEL, IC ENGINE, CATERPILLAR, MODEL 3516BDITA, 2,848 HP A/N 391430	D10		NOx: PROCES S UNIT	**NOx**: 6.65 GM/BHP-HR (4) [RULE 2005]; NOx: 290 LBS/1000 GAL(1) [RULE 2012]; **CO**: 1.01 GM/BHP-HR (4) [RULE 1303]; **VOC**: 0.14 GM/BHP-HR (4) [RULE 1303];	1-1, 12-4, 12-5, 67-2,193-1, 296-1
EMERGENCY FIRE PUMP, ENGINE, DIESEL, ~~CATERPILLAR~~ CLARKE, MODEL ~~3406B~~ JW6H-UF40, ~~337~~ 300 BHP A/N 391431	~~D10~~ D11		NOx: PROCES S UNIT	**NOx**: ~~5.89~~ 5.20 GM/BHP-HR (4) [RULE 2005]; NOx: ~~240~~ 237 LBS/1000 GAL (1) [RULE 2012]; **CO**: ~~3.55~~ 0.27 GM/BHP-HR (4) [RULE 1303]; ~~ROG~~ **VOC**: ~~1.0~~ 0.15 GM/BHP-HR (4) [RULE 1303];	1-1, 12-4,12-5, 67-2,193-1, 296-1

PROCESS 2: INORGANIC CHEMICAL STORAGE SYSTEM 1: AMMONIA STORAGE TANKS					
STORAGE TANK, ~~SERVING TURBINE #1~~, WITH A VAPOR RETURN LINE, 28% WT AQUEOUS AMMONIA SOLUTION, 16,000 GAL. A/N 391428	D7				144-1, 157-1, 193-1
STORAGE TANK, ~~SERVING TURBINE #2~~, WITH A VAPOR RETURN LINE, 28% WT AQUEOUS AMMONIA SOLUTION, 16,000 GAL. A/N 391429	D8				144-1, 157-1, 193-1
PROCESS 3: RULE 219 EXEMPT EQUIPMENT SUBJECT TO SOURCE-SPECIFIC RULE					
Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
RULE 219 EXEMPT EQUIPMENT, COATING EQUIPMENT, ARCHITECTURE COATINGS	E			~~ROG~~ **<u>VOC</u>**: (9) [RULE 1113, 5-4-1999; RULE 1171, 6-13-1997]	67-3
RULE 219 EXEMPT CLEANING EQUIPMENT USING SOLVENTS	E			~~ROG~~ **<u>VOC</u>**: (9) [RULE 1171, 6-13-1997]	23-1

3.2 Biological Resources

Biological resources issues were addressed in the 2001 AFC and agency consultation with CEC, U.S. Fish and Wildlife Service (USFWS), California Department of Fish and Game (CDFG), Riverside County Habitat Conservation Agency, and Army Corps of Engineers (USACE). The following provides a supplemental assessment of the potential effects on biological resources associated with the turbine reconfiguration and new construction parking and laydown areas as proposed in this license Amendment application. This analysis also provides an update of the environmental baseline in terms of sensitive species database records for the project area.

3.2.1 Environmental Baseline Information

The newly proposed construction parking and secondary laydown areas are located on parcels that adjoin the power plant site and are within the analysis area as described in the 2001 AFC (Figure 3.2-1). The following subsections describe the biological conditions of the new areas proposed for project changes, including vegetation types and habitat present, and special-status species known to occur in the general region.

3.2.1.1 Habitat and Vegetation Communities

The habitat potentially affected in the new construction parking and laydown area can be characterized as a ruderal field (see Figure 3.2-1). These habitat types and vegetation communities coincide with the habitat and vegetation communities defined and described in the 2001 AFC. The overall IEEC project area is described as “developed and disturbed land” in the Riverside County Integrated Project Multiple Species Habitat Conservation Plan (MSHCP) (Riverside County 2003). The new laydown area does not include seasonal wetlands or other potential federal-listed vernal pool branchiopod habitat.

3.2.1.2 Special-Status Species

The AFC includes a list of special-status plant and wildlife species compiled for the project area based upon the following references: (1) the CDFG California Natural Diversity Data Base (CNDDB), (2) a USFWS species list for the area, (3) informal consultations with USFWS and USACE agency personnel, and (4) project-specific field surveys. Both the USFWS list and CNDDB were updated for this Amendment.

The 2001 AFC included the results of a CNDDB search of the Perris, Romoland, Lakeview, Sunnymead, and El Casco 7.5-minute USGS topographical quadrangles. The project owner later eliminated the Alternative B natural gas pipeline route extending north of the main site and into the Sunnymead and El Casco quadrangle vicinities. For this reason, those two quadrangles were not included in the recent database searches. The Winchester quadrangle was added for additional coverage of the project area. The results for the February 2005 CNDDB search are included in Figure 3.2-2.

The 2005 CNDDB search results do not warrant the assessment of any special-status species not already included in the 2001 AFC or suggest the need for additional impact analysis of species included in the 2001 AFC.

Supplementary reconnaissance-level field surveys were performed by CH2M HILL biologists Debra Crowe on October 5, 2004 and John Cleckler on January 14, 2005 to characterize the biological resources for the additional project features addressed in this Amendment. The qualifications of the field biologists are provided in Appendix 3.2.

Special-Status Plants

The analysis conducted for the 2001 AFC indicated that, at that time, 12 special-status plant species had the potential to occur in the project area. A new CNDDB search conducted for this Amendment did not result in any additions to this list that would require additional consideration for project impacts. No special-status plant species were observed in the project survey areas during protocol-level surveys conducted in support of the 2001 AFC and no evidence of these plant species was discovered during field reconnaissance for this Amendment, either on the power plant site or in the newly identified construction laydown area.

Special-Status Wildlife

The analysis conducted for the 2001 AFC indicated that, at that time, 13 special-status wildlife species had the potential to occur in the general project area. A new CNDDB search conducted for this Amendment did not result in additions to this list that would require additional consideration for project impacts. Further analysis of existing habitat and known species distribution, and particularly the elimination of natural gas pipeline Alternative B, shortened the list to 2 species with the potential to occur near the project site: vernal pool fairy shrimp (*Branchinecta lynchi*) and western burrowing owl (*Athene cunicularia hypugea*).

No special-status wildlife species were observed in the project vicinity during protocol-level surveys conducted in support of the 2001 AFC. Inconclusive sampling of potential fairy shrimp habitat resulted in an agreement between the project owner and USFWS to avoid vernal pool fairy shrimp in depression MW-51, adjacent to McLaughlin Road (Figure 3.2-1) along the transmission interconnection route approved in the Commission Decision. No changes are proposed in the vicinity of MW-51 in this Amendment.

Potential burrowing owl habitat was identified in the ruderal fields, roadsides, and crop margins within the project area, although no appropriate-sized mammal burrows or associated owl sign (feathers, pellets, prey items) were observed during past or recent surveys. Burrowing owl avoidance measures will be developed as part of the Biological Resources Mitigation Implementation and Monitoring Plan (BRMIMP) (Condition BIO-5) in case burrowing owls move into the area and are found during pre-construction surveys or project construction.

The project area is located entirely within the Stephens' kangaroo rat (SKR) fee area as defined by the SKR Habitat Conservation Plan (HCP). Therefore, a prescribed fee must be paid, based on the total project acreage.

3.2.1.3 Biological Surveys

The biological resources evaluation is primarily based on the biological field surveys, agency consultation, and resulting analysis performed in support of the 2001 AFC. Supplementary field surveys were performed for this Amendment as described above,

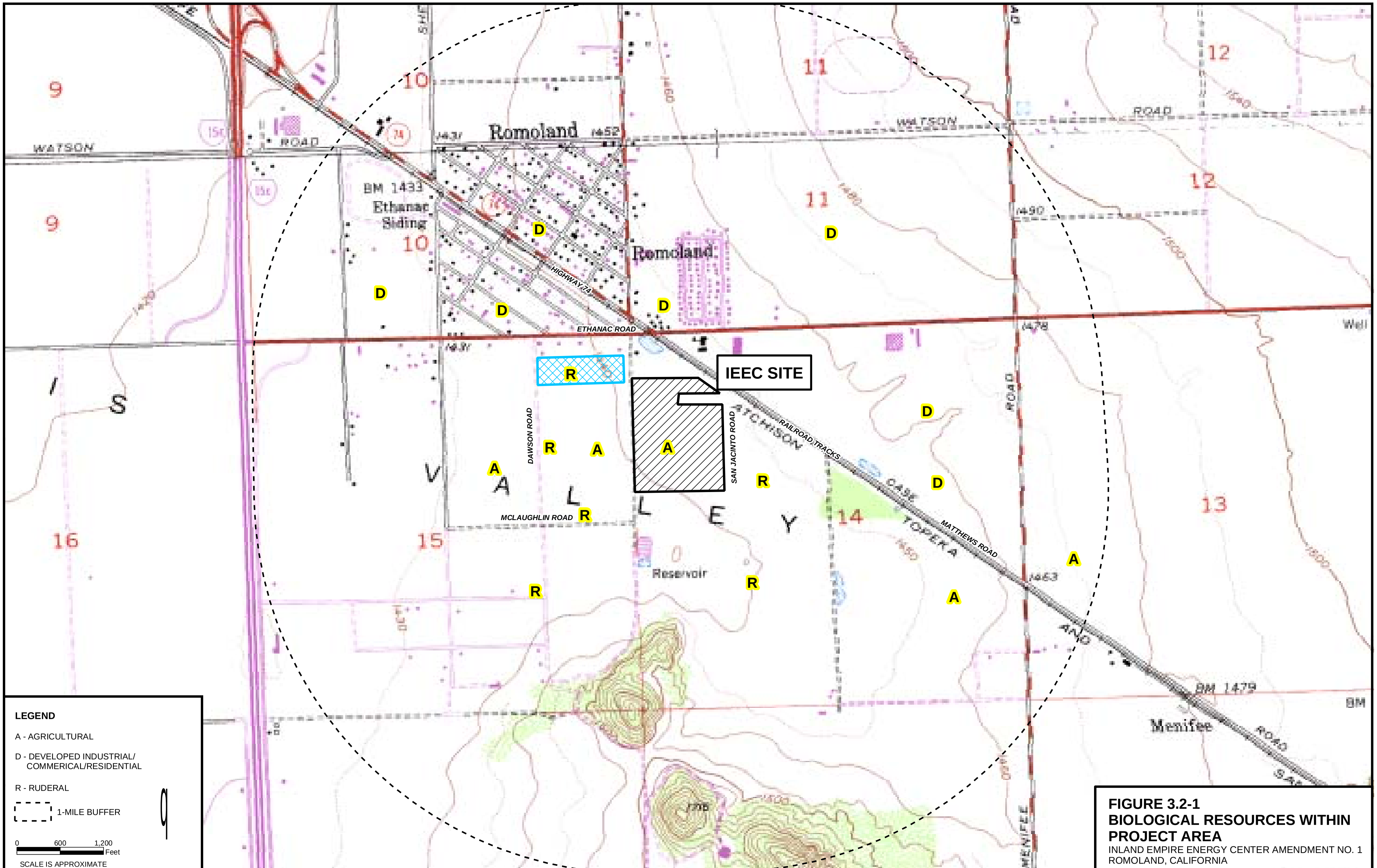


FIGURE 3.2-1
BIOLOGICAL RESOURCES WITHIN PROJECT AREA
INLAND EMPIRE ENERGY CENTER AMENDMENT NO. 1
ROMOLAND, CALIFORNIA

CH2MHILL

RDD \\LOKI\PROJECTS\RDDGIS\IEEC\MXDS\FIG3_2_1_BIOLOGY.MXD 3/2/2005 14:13:41

1	BELL'S SAGE SPARROW
2	BURROWING OWL
3	CALIFORNIA HORNED LARK
4	COASTAL CALIFORNIA GNATCATCHER
5	COULTER'S GOLDFIELDS
6	LOS ANGELES POCKET MOUSE
7	MUNZ'S ONION
8	NORTHWESTERN SAN DIEGO POCKET MOUSE
9	ORANGE-THROATED WHIPTAIL
10	RIVERSIDE FAIRY SHRIMP
11	ROBINSON'S PEPPER-GRASS
12	SAN JACINTO VALLEY CROWNSCALE
13	SMOOTH TARPLANT
14	SOUTHERN CALIFORNIA RUFOUS-CROWNED SPAR
15	SOUTHERN COAST LIVE OAK RIPARIAN FOREST
16	SOUTHERN COTTONWOOD WILLOW RIPARIAN FOR
17	SPREADING NAVARRETIA
18	STEPHENS' KANGAROO RAT

LEGEND

SPECIAL-STATUS SPECIES

PROJECT LOCATION

10-MILE BUFFER

SOURCE: CNDDB JANUARY 2005

0 2.25 4.5 Miles

SCALE IS APPROXIMATE

FIGURE 3.2-2
SPECIAL-STATUS SPECIES WITHIN A 10-MILE RADIUS OF THE IEEC SITE

INLAND EMPIRE ENERGY CENTER AMENDMENT NO. 1
ROMOLAND, CALIFORNIA

CH2MHILL

RDD \\LOKI\PROJECTS\RDDGIS\IEEC\MXDS\FIG3_2_2_CNDDB.MXD 3/2/2005 14:23:24

to characterize the biological resources for the additional construction laydown area addressed in this Amendment.

As with the initial field surveys, the 2004/2005 reconnaissance-level biological surveys focused on characterization and potential impacts associated with vegetation communities, wetlands, wildlife, and wildlife habitats in the vicinity of the new temporary and permanent impact areas. The field surveys were aided by aerial photographs, which helped identify land uses on the site and surrounding areas. The presence or potential presence of sensitive biological resources was determined from the former biological studies, the 2004/2005 field surveys, published and unpublished literature, and natural resource agency databases. A list of wildlife species observed during the 2004/2005 biological surveys is included in Table 3.2-1. Additional surveys will be conducted for nesting birds in the early spring (mid-February to April).

TABLE 3.2-1
Wildlife Species Observed During the Biological Reconnaissance Visits of the IEEC Project Area

Common Name	Scientific Name	Location	Sign
Reptiles			
Western fence lizard	*Sceloporus occidentalis*	Open ruderal field north of proposed transmission line	Carcass observed
Birds			
Turkey vulture	*Cathartes aura*	Flying over general vicinity	Observed
Red-tailed hawk	*Buteo jamiacensis*	Flying over general vicinity	Observed
Killdeer	*Charadrius vociferus*	Adjacent ruderal fields and along roads and open fields in the general vicinity	Observed
Rock dove	*Columba livia*	Throughout general vicinity	Observed
Mourning dove	*Zenaida macroura*	New laydown area	Observed
American crow	*Corvus brachyrhynchos*	Flying over general vicinity	Observed
Horned lark	*Eremophila alpestris*	Adjacent agricultural fields	Observed
Western meadowlark	*Sturnella neglecta*	Adjacent agricultural fields	Observed
Mammals			
California ground squirrel	*Spermophilus beecheyi*	Margins of new laydown area and in general vicinity along rail road berms and other locations within open areas	Observed
Desert cottontail	*Sylvilagus audubonii*	Along McLaughlin Road	Observed
Domestic dog	*Canis familiaris*	Throughout	Tracks

Turbine Configuration

Changes in the turbine configuration do not involve changes to the IEEC site boundaries, and will not affect sensitive plants or wildlife or their habitats, beyond the effects identified in the 2001 AFC.

Additional Construction Laydown Area

The revised site construction plan makes use of additional areas for construction parking and equipment storage. The additional laydown area is located on two individual but adjoining properties, adjacent to the IEEC site (Figure 3.2-1). The new laydown area is fenced and subjected to considerable past and ongoing disturbance and can be characterized as ruderal fields, referred to as "urban/exotic/residential vegetation community with a strong non-native component" in the 2001 AFC. Currently, this area is primarily being used for storage (eg., mobile homes) but includes open areas with non-native grasses and other ground cover. Although degraded, the fields do represent open habitat that provides some foraging opportunities for raptors that may prey on small mammals, birds, and reptiles.

3.2.2 Environmental Consequences

In the 2001 AFC, potential direct and indirect impacts to biological resources were evaluated to determine the permanent and temporary effects of project construction, operation, maintenance, and decommissioning of the IEEC project and supporting facilities. The following includes an evaluation of the impacts associated with the proposed changes to the original project.

3.2.2.1 Standards of Significance

As with the 2001 analysis, impacts on biological resources are considered significant if one or more of the following conditions could result from implementation of the proposed project:

- Substantial effect, reduction in numbers, restricted range, or loss of habitat for a population of a state or federally listed threatened or endangered species
- Substantial effect, reduction in numbers, restricted range, or loss of habitat for a population of a California special-status species, including fully protected, candidate proposed for listing, California Species of Concern (CSC), and some California Native Plant Society (CNPS) list designations
- Substantial interference with the movement of resident or migratory fish or wildlife species
- Substantial reduction of habitat for native fish, wildlife, or plants
- Substantial disturbance of wetlands, marshes, riparian woodlands, and other wildlife habitat
- Removal of trees designated as heritage or significant under County or local ordinances

3.2.2.2 Potential Impacts of Construction and Use of Additional Temporary Construction Laydown Area

Use of the additional laydown area will result in temporary impacts to approximately 9.6 acres (Figure 3.2-1). The area is currently disturbed, the dominant vegetation is non-native ruderal, and the parcels are currently being used for equipment and materials storage. Although the quality of the land as wildlife habitat is marginal, it could be used seasonally by foraging birds, small mammals, and reptiles. These properties may require temporary gravel placement to support materials and equipment and will likely be reclaimed for storage following project completion.

Special-Status Species

No special-status species have been observed or recorded by past project-specific database searches or surveys for the project area. The additional laydown area does not include unique habitat features that would provide habitat for special-status species not addressed in the 2001 AFC. The additional laydown area does expand the temporary disturbance acreage of the overall project, which will be reflected in a recalculated mitigation fee for SKR.

As mentioned above, the entire project is within the SKR fee area as defined by the SKR Habitat Conservation Plan (HCP). The additional, new laydown area is not characterized by shrub and grassland habitats associated with the SKR, but is within the HCP fee area. The HCP fee will be recalculated for the project at the prescribed rate of $500.00 per acre. Additional agency consultation on this matter will not be required. Fee payment to the Riverside County Habitat Conservation Agency will fully mitigate potential SKR impacts and further consultation can be completed informally.

Wetlands and Waters of the U.S.

No jurisdictional wetlands or waters are present within the new construction parking and laydown area. A ditch runs along the north boundary of this area, redirecting surface runoff from the adjacent fields, roads, and industrial development (Figure 3.2-1).

CDFG indicated that it would not require a Streambed Alteration Agreement (SAA) for any of the drainage or depression features in the project area. The Commission Decision Conditions of Certification currently address compliance with Clean Water Act Sections 404 and 401.

Recycled water will be applied to the laydown area for dust control during construction. Additional erosion and sediment discharge would be potentially harmful to water quality of adjacent drainage ditches. The Applicant would be required to have a Storm Water Pollution Prevention Plan (SWPPP) as part of compliance with a construction National Pollutant Discharge Elimination System (NPDES) permit. The permit specifies best management practices (BMPs) to avoid sediment runoff and erosion that would cause water quality degradation.

3.2.3 Mitigation Measures

Additional mitigation measures (beyond those of the Commission Decision) are not required for this Amendment other than to recalculate the SKR fee. The existing measures will be adequate and adopted for the revised project and construction plans. Section 3.2.6 contains suggested modifications to one of the Conditions of Certification, accounting for revised acreages on which SKR mitigation fees are based.

3.2.4 Consistency with LORS

The construction and operation of the IEEC, as amended, will conform with all applicable LORS related to biological resources.

3.2.5 References Cited

California Energy Commission. 2003. Commission Decision, Inland Empire Energy Center, Application for Certification (01-AFC-17), Riverside County. California Energy Commission, Sacramento, California. December 22, 2003.

Calpine Corporation. 2001. Inland Empire Energy Center Application for Certification. August 2001.

Calpine Corporation. 2002a. Inland Empire Energy Center Biological Issues Summary. Prepared to Respond to USFWS Carlsbad Office Letter Dated April 19, 2002.

Calpine Corporation. 2002b. Inland Empire Energy Center Data Responses. Responses to California Energy Commission Data Requests for the Application for Certification. February 13, 2002.

Calpine Corporation. 2002c. Inland Empire Energy Center – Request for Nationwide Permit No. 12. Sent to Robert Smith, U.S. Army Corps of Engineers, Los Angeles District on May 17, 2002.

Calpine Corporation. 2002d. Inland Empire Energy Center – Request for Section 401 Water Quality Certification and Report of Waste Discharge Requirements. Sent to Kelly Schmoker, California Regional Water Quality Control Board, Santa Ana Region on May 17, 2002.

CDFG. 2002. California Natural Diversity Data Base. Search of the Perris, Romoland, Lakeview, and Winchester, 7.5-minute USGS quadrangles. January 18, 2005 Revision.

Riverside County. 2003. Riverside County Integrated Project Multiple Species Habitat Conservation Plan (MSHCP). Website: http://rcip.org/conservation.htm. Adopted June 17, 2003.

3.2.6 Conditions of Certification

The addition of the 9.6-acre construction parking and secondary laydown area increases the acreage of temporary disturbance from 36.13 to 45.73 acres. The final acreage will be assessed at the time of final compliance with the ordinance. We suggest deleting the specifications of acreage from the condition.

BIO-11 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 project owner shall purchase habitat credits for temporary ~~impacts to 36.13 acres~~ and permanent impacts ~~to 38.60 acres~~. Fees shall be based on the most current fees assessed by Riverside County. Monies shall be paid directly to the Riverside County Habitat Conservation Agency

3.3 Cultural Resources

The turbine reconfiguration would not involve new ground disturbing activities that could affect cultural resources differently than described in the Commission Decision. The additional construction laydown areas, however, involve the potential disturbance of areas not previously considered for construction activity. For this reason, the Project Owner conducted additional field inventory to determine whether or not significant cultural resources are present in the proposed new laydown areas.

3.3.1 Environmental Baseline Information

The Project Owner conducted a cultural resources field inventory of the proposed new construction parking and secondary laydown area. Ms. Raena Ballantyne conducted the inventory on January 15, 2005 by walking the parking and laydown parcels in systematic, linear transects spaced 20 meters apart or less. A resume for Ms. Ballantyne is provided in Appendix 3.3. Figure 3.3-1 depicts the areas covered in the intensive pedestrian survey.

The new construction parking and secondary laydown area consists of the Grabowski (APN 331-150-040) and Anderson (APN 331-150-039) parcels. These are adjacent to one another and managed as a single property. The Anderson parcel is located on the west side of Antelope Road, diagonal to the northwest corner of the parcel on which the IEEC is located. The Grabowski Parcel is west of the Anderson parcel, and lies on Dawson Road. These two parcels are 4.86 and 4.77 acres, respectively (total 9.63 acres). They were overgrown with vegetation and had standing water in places at the time of survey. There are several mounds of deposited gravel, earth, or concrete fill on the property. The landowner, Mr. Anderson, indicated that the property had been used in the past for the size-sorting of concrete rubble. Mr. Anderson also reported that the land had been used agriculturally for winter wheat and other crops, before its conversion for use as a staging, processing, and storage area.

Ground visibility varied from 10 to 100 percent. In areas where ground visibility was poor, vegetation was scraped away at intervals with a trowel to allow for observation of the ground surface. Soils consisted of silty sand with gravel and concrete inclusions. A man-made drainage ditch runs along the northern edges of the property. It measures 5 to 7 feet wide and is 1 to 3 feet deep. The base of this ditch is lined with large cobbles. The property owner, Mr. Anderson, indicated that he created this ditch to drain water from the property. Profiles in this ditch were carefully inspected for evidence of cultural materials.

3.3.2 Environmental Consequences

The surveys did not result in the identification or recording of cultural resources. Because no cultural resources were discovered on the construction laydown areas, project changes due to the adoption of new turbine technology and the new laydown areas would not result in any changes to the potential impacts of the project.

3.3.3 Mitigation Measures

No significant impacts to cultural resources would result from the approval of this Amendment. Therefore, mitigation measures beyond those stipulated in the Commission Decision are not necessary.

3.3.4 Consistency with LORS

The construction and operation of the IEEC, as amended, will conform with all applicable LORS related to cultural resources.

3.3.5 Conditions of Certification

This Amendment does not require changes to the Cultural Resources Conditions of Certification.

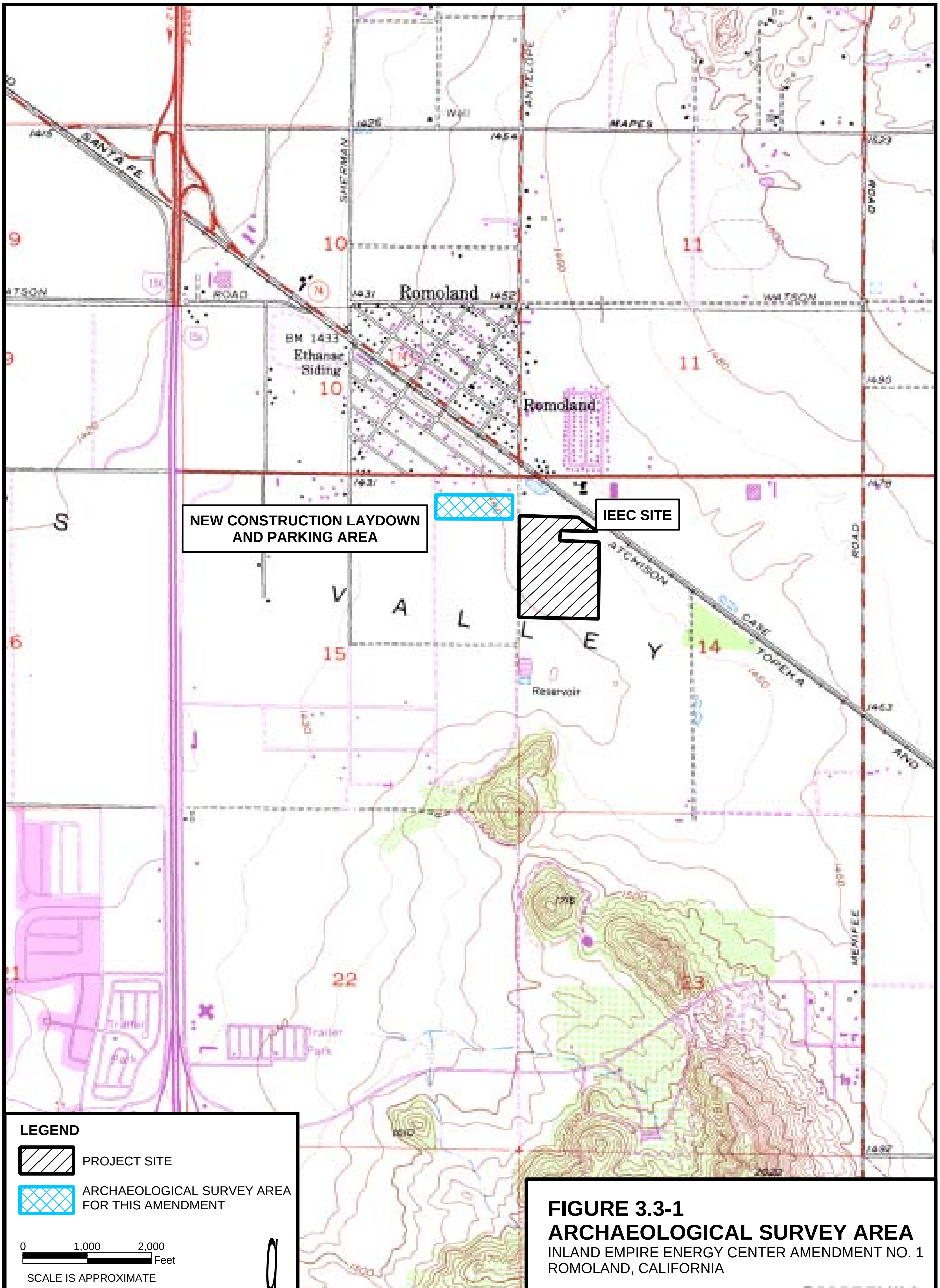


FIGURE 3.3-1
ARCHAEOLOGICAL SURVEY AREA
INLAND EMPIRE ENERGY CENTER AMENDMENT NO. 1
ROMOLAND, CALIFORNIA

CH2MHILL

3.4 Geology and Paleontology

The new turbine configuration would not result in potential impacts to geological resources or paleontological resources and would not cause geological hazards beyond those analyzed by the Commission during certification. There will be no significant construction or operation disturbance below the ground surface beyond the scope considered in the Commission Decision.

The addition of new construction laydown areas could involve minor disturbance of areas not considered in the Commission Decision. This disturbance would take place on or at the surface, however, and so would be unlikely to affect significant geological or paleontological resources. Furthermore, with the implementation of the mitigation measures contained in the Commission Decision for the project, such as paleontological resource monitoring and worker environmental awareness training, any potential impacts would be reduced to a level of insignificance.

3.4.1 Mitigation Measures

No significant impacts to geological or paleontological resources would result from the approval of this Amendment. Therefore, mitigation measures beyond those stipulated in the Commission Decision are not necessary.

3.4.2 Consistency with LORS

The construction and operation of the IEEC, as amended, will conform with all applicable LORS related to geological and paleontological resources.

3.4.3 Conditions of Certification

This Amendment does not require changes to the Geology and Paleontology Conditions of Certification.

3.5 Hazardous Materials Management

The chemical inventory for the IEEC project is set forth in Appendix C of the Hazardous Materials section of the Commission Decision. Quantities of the chemicals in Appendix C to the Commission Decision would not change due to the adoption of GE S107H System.

There would be only one addition to the list of chemicals to be used resulting from the reconfiguration of turbine technology for the project as described in this Amendment. The GE S107H system involves the use of chiller refrigerant HFC R 123. This material is sealed inside the chiller equipment (see Item 44 on Figure 2-1 in Section 2.0). There are four chillers, each with 4,200 pounds of HFC R-123. The total quantity on site would thus be less than 18,000 pounds.

HFC R-123 (2,2-dichloro-1,1,1-trifluoroethane or dichlorotrifluoroethane) is a clear, colorless liquid with a slight, ether-like odor. R-123 has no CERCLA-SARA reportable quantities and is not listed under Proposition 65. It has no threshold planning quantity under the California Accidental Release Program (CalARP). This material can be toxic if inhaled in sufficiently high concentrations. Inhalation can cause temporary nervous system depression with anesthetic effects and may contribute to irregular heartbeat. This substance is also a mild eye irritant. R-123 is reactive with alkaline earth metals, such as powdered aluminum, zinc, and beryllium. Though non-flammable, handling should avoid open flame and high temperatures, as thermal decomposition products may include fluorides, chlorides, and phosgene. The CAS number is 306-84-2. This material will be incorporated into the IEEC health and safety programs as required by various Conditions of Certification in the Commission Decision including Worker Safety, Hazardous Materials Management, and Waste Management as appropriate.

3.5.1 Mitigation Measures

No significant impacts in terms of hazardous materials handling would result from the approval of this Amendment. Therefore, mitigation measures beyond those stipulated in the Commission Decision are not necessary.

3.5.2 Consistency with LORS

The construction and operation of the IEEC, as amended, will conform with all applicable LORS related to hazardous materials.

3.5.3 Conditions of Certification

This Amendment does not require changes to the Hazardous Materials Conditions of Certification.

3.6 Land Use

The IEEC project modifications as described in Chapter 2, including the additional construction laydown parcels (see Figure 2-12), would not involve significant changes to the land use findings and conclusions, compared with those described in the Commission Decision. The project site land use designation under the Riverside County Comprehensive General Plan is Heavy Industrial (HI). The site is zoned under the County Zoning Ordinance as a Specific Plan zone. The project site is within Area 3 of the County's Menifee North Specific Plan (SP No. 260) which has a land use designation of Industrial, and a zoning designation of Industrial per the Menifee North Specific plan which reflects the County's M-H zone as defined in Ordinance 348. The Menifee North Specific Plan is both a Riverside County Comprehensive General Plan Amendment and a County Zoning Ordinance Amendment. The new construction temporary staging and parking uses are also located in the Menifee North Specific Plan area, in Planning Area 2. Similar to Area 3, Area 2 has a land use designation of Industrial, and a zoning designation of Industrial per the Menifee North Specific plan that reflects the County's M-H zone as defined in Ordinance 348. The zoning is also Heavy Industrial per the Riverside County Comprehensive General Plan.

The Riverside County Integrated Project included long-term transportation. One of the alternatives considered had a potential impact to the IEEC site and was identified during the AFC process. That alternative has since been eliminated. Appendix 3.6 includes a copy of a confirming letter from the Riverside County Transportation Commission.

The change in power generation configuration is entirely within the site approved in the Commission Decision and has no potential land use impacts. The construction laydown areas are consistent with local land use plans, ordinances, and policies. Also, the parcels adjacent to the proposed construction laydown area are similarly used for the storage of heavy construction equipment. The use of the temporary construction laydown area is therefore compatible with existing and planned land uses.

3.6.1 Environmental Baseline Information

New baseline information that is relevant in this discipline includes a revision to the Riverside County General Plan, published October 2003 (County of Riverside 2003). There are no significant changes to zoning regulations that pertain to Land Use in Planning Areas 2 and 3 of the Menifee North Specific Plan in this General Plan revision.

3.6.2 Environmental Consequences

No significant impacts to land use would result from the approval of this Amendment.

3.6.3 Mitigation Measures

No significant impacts to land use would result from the approval of this Amendment. Therefore, mitigation measures beyond those stipulated in the Commission Decision are not necessary.

3.6.4 Consistency with LORS

The construction and operation of the IEEC, as amended, will conform with all applicable LORS related to land use.

3.6.5 References Cited

County of Riverside. 2003. County of Riverside General Plan, Adopted October 7, 2003, Final Integrated Version. Riverside, California.

County of Riverside. 1995. Menifee North Specific Plan, Specific Plan No. 260, Adopted December 27, 1994. Riverside, California.

3.6.6 Conditions of Certification

This Amendment does not require changes to the Land Use Condition of Certification.

3.7 Noise and Vibration

The use of the new construction laydown areas will be temporary and will not involve a change in the conclusions of the Commission Decision. The turbine reconfiguration will involve an additional steam turbine and different noise generation profile for the combustion turbine equipment and some other equipment than was previously considered. For this reason, this Amendment includes a noise modeling analysis of the reconfigured power plant.

3.7.1 Environmental Baseline Information

The background (ambient) noise levels in the vicinity of the project have not changed significantly since certification, and there are no new sensitive noise receptors in the area that are located nearer to the project site than the existing project design points. Although there is a new residential subdivision along Menifee Road more than a mile east-northeast of the project, the potential effects on this subdivision are taken into consideration by noise modeling at design points that are much nearer to the project site, including DP-4, north of the project, and DP-3, southeast of the project.

As for the AFC, noise modeling was performed using the Cadna/A noise modeling program, produced by the German firm DataKustik, GmdH, specifically for power plant noise modeling applications. Inputs to this model were based on a combination of manufacturer estimates and field measurements from similar equipment. Since there are currently no GE S107H Systems in operation, the CT and HRSG noise emissions were estimated based on actual field data from projects utilizing GE 7FA turbines with appropriate adjustments made, where necessary, to scale up the noise emissions for the larger GE S107H System.

3.7.2 Environmental Consequences

Figure 3.7-1 shows the plant operation noise contours generated by the noise modeling program as well as the locations of the four design points (DPs), representing the closest sensitive receptors. Table 3.7-1 compares the expected energy center noise levels with the design goal of 45 dBA, at each of the four locations. As shown in Table 3.7-1, the IEEC is expected to produce noise levels that are equal to or below the design goal.

TABLE 3.7-1
Expected Energy Center Performance at Nearby Sensitive Receptors

Location	Expected Energy Center Noise Level During Full Load Operation, dBA L_{eq}	Energy Center Design Goal, dBA L_{eq}
DP-1. Ethanac Road	44	45
DP-2. McLaughlin & Dawson Roads	45	45
DP-3. McLaughlin & Palomar Roads	44	45
DP-4. Highway 74 North of Site	44	45

For a continuous noise source, the L_{eq} will approximate the L_{50}. Thus, the amended project design and its implementation will include appropriate mitigation measures adequate to ensure that the noise level produced by operation of the project (including the gas compressor station) will not exceed an L_{50} of 45 dBA measured at any residence.
Table 3.7-2 shows the existing CNEL, projected plant CNEL, combined CNEL, and CNEL increase at each of the design point locations, based on the plant achieving the design goal of 45 dBA at each location.

TABLE 3.7-2
Existing and Future Community Noise Equivalent Levels (CNEL) at Nearest Residential Receptors Assuming 45-dBA Design Goal

	Ambient Noise Survey CNEL, dBA	Energy Center Design Goal CNEL, dBA*	Projected Combined CNEL, dBA**	Increase in CNEL, dBA
Location 1 (DP-1)	62	52	63	1
Location 2 (DP-2)	56	52	58	2
DP-3	56 (Estimated to be similar to DP-2)	52	58	2
DP-4	62 (Estimated to be similar to DP-1)	52	63	1

*Assuming continuous 24 hours per day operation at 45 dBA L_{eq}.
**The numbers are added logarithmically.

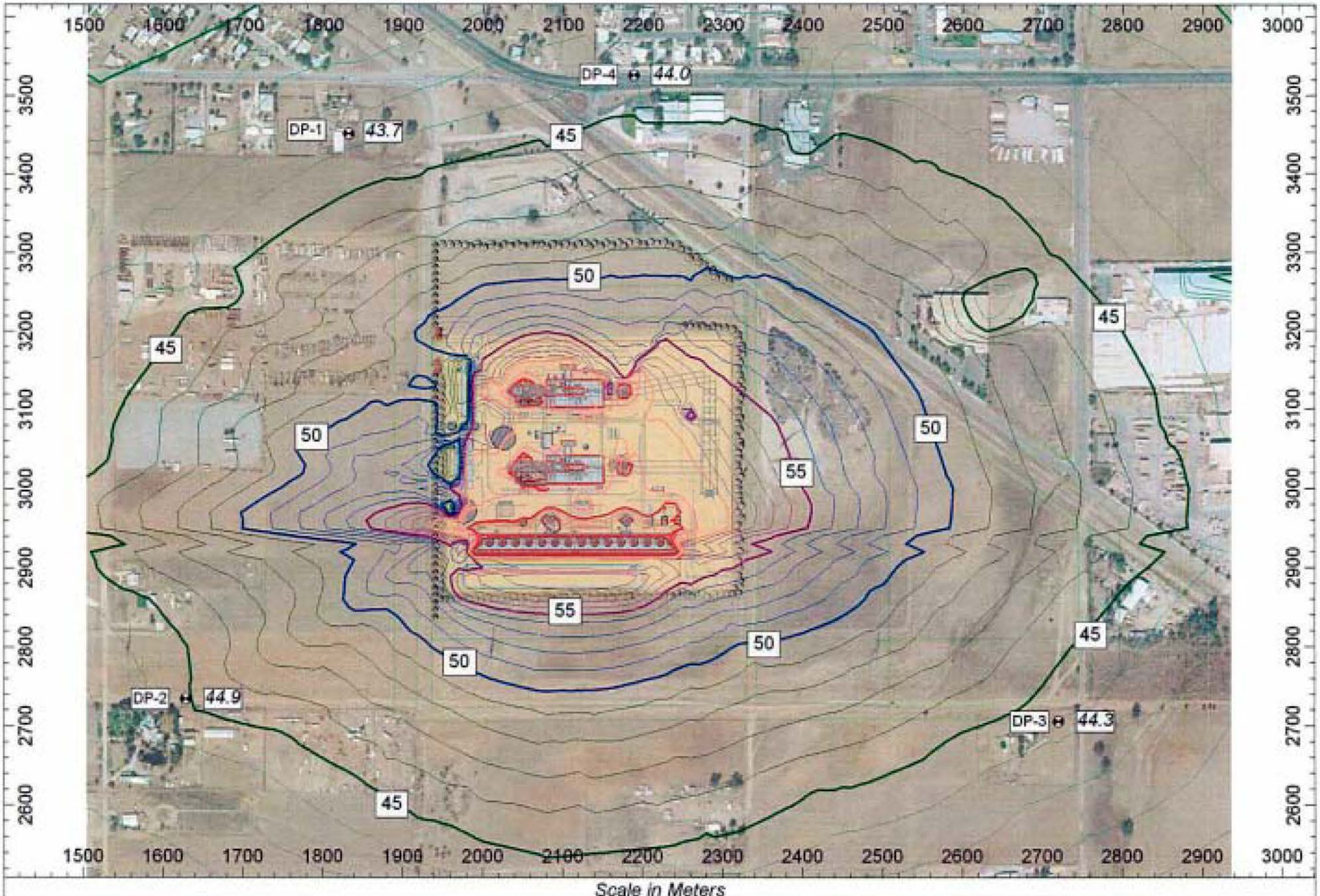
As shown in Table 3.7-2, little change is anticipated in the CNELs after the addition of the IEEC as amended, and the overall cumulative values are still expected to be below the 65 dBA exterior CNEL that the County of Riverside uses to assess the compatibility of residential land uses with noise sources.

The construction noise levels are expected to be similar to those previously analyzed.

3.7.3 Noise Attenuation Measures

Plant noise contours depicted in Figure 3.7-1 are based on the following noise attenuation measures:

- The turbine operating deck structures will include acoustical cladding extending from grade to the deck level on all four sides, except for small openings in the southwest corner where the pipe racks exit the structures. The structures will be equipped with insulated roll-up doors and deck openings will generally be sealed with checker plate or removable hatches where grating would otherwise typically be used. These mitigation measures will significantly reduce the noise from the bottom side of the steam turbine, condenser, condensate pumps, steam control valves and bypass valves, and other miscellaneous mechanical equipment located beneath the operating deck.
- Each steam turbine (ST) will include an acoustical enclosure over the high-pressure and intermediate-pressure turbines and shaft areas and acoustical lagging on the low-pressure turbine casing.
- Each combustion turbine (CT) will be provided with an acoustical enclosure, air inlet silencer, and enclosure exhaust fan silencers.



N **Hessler Associates, Inc.** Consultants in Engineering Acoustics Drawing #: IE-Rev-M-3	**Inland Empire Energy Center Amendment No. 1**	Description: **FIGURE 3.7-1** EXPECTED NOISE EMISSION CONTOURS FROM ATTENUATED ENERGY CENTER	Prepared for: **GE Energy** Date: October 13, 2004

- The lube oil skid for the north GE S107H System will be provided with an acoustical barrier or enclosure.
- The CT exhaust diffuser will be provided with a noise enclosure.
- The heat recovery steam generator (HRSG) transition ducts will be provided with external barrier walls to reduce the noise emanating from the sidewalls of the ducts.
- The HRSG stacks will be provided with internal silencers.
- The HRSG atmospheric blowdown tanks will be acoustically lagged and provided with vent stack silencers.
- The boiler feed pump areas will be provided with noise barrier walls. These walls will run along the south and west sides of the pipe rack and will also help to contain pipe rack noise.
- A noise barrier wall will be provided on the south side of the cooling towers to reduce the noise emitted from the cooling tower inlets, including basin splash noise.
- The chillers used for the CT inlet air cooling system will be located inside an acoustically treated building.
- Each gas compressor will be provided with a dedicated acoustical enclosure.
- The condensate tank vents and HRSG startup vents will be provided with silencers.

3.7.4 Consistency with LORS

Design, construction and operation of the IEEC, including transmission lines, pipelines, and ancillary facilities will conform to all worker safety and health noise limits and will be conducted in accordance with applicable LORS relating to project noise. The noise from the IEEC, as amended, will remain below all applicable community and residential noise standards.

3.7.5 References Cited

California Energy Commission. 2003. Commission Decision, Inland Empire Energy Center, Application for Certification (01-AFC-17), Riverside County. California Energy Commission, Sacramento, California. December 22, 2003.

3.7.6 Revisions to Conditions of Certification

For the GE S107H System, the owner proposes high-pressure air blow process for cleaning steam piping. Condition NOISE-4 should thus be revised as follow:

NOISE-4 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 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.

Verification: 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.

3.8 Public Health

The changes in turbine technology proposed in this Amendment will involve changes in air emissions. For this reason, the toxic air contaminant emissions were recalculated and screening-level human health risk assessment modeling rerun for this Amendment.

3.8.1 Environmental Baseline Information

Table 3.8-1 is an updated list of sensitive receptors within 6 miles of the project site.

TABLE 3.8-1
Sensitive Receptors Within 6 miles of IEEC

Receptor	Miles	Receptor	Miles
Schools:			
A Street Elementary School	5.01	Redeemer Christian School	4.57
Ambassador Christian Academy	4.69	Redeemer Lutheran School	4.93
Cali Kirpatrick Elementary School	4.31	Ridgemoor Elementary School	3.87
Chester W Morrison Elementary School	4.36	Romoland Elementary School	0.34
Choice 2000 On Line School	5.44	Sanders Elementary School	4.17
Enchanted Hill Elementary School	5.60	St James School	4.40
Grace Preparatory School	5.54	Temple Christian School	4.66
Harvest Valley Elementary School	2.03	Tri-City Adventist Christian School	4.00
Menifee School	4.42	Valley View Elementary School	5.94
Mt San Jacinto Col-Menifee	4.56	**Child Care Centers:**	
Nan Sanders Elementary School	5.32	Children’s Center	3.92
New view Elementary School	5.86	Little Steps Child Dev. Center	5.01
Oliver Christian School Center	3.79	NAACP Head Start Preschool	5.36
Palms Elementary School	4.38	Newport Child Development Ctr	3.45
Paloma Valley High School	5.52	Park Towne Child Care Ctr	4.21
Park Avenue Elementary	4.59	Redeemer Lutheran Daycare	4.93
Perris Elementary School	4.94	Romoland Head Start	0.34
Perris High School	3.72	**Hospitals:**	
Perris Lake High school	4.02	Medical Art Conv. Hospital	5.70
Perris Union High School	4.96	Menifee Valley Medical Center	1.74
Pinacate Middle School	3.89	Valley Plaza Drs. Hospital	5.79
Praise Fellowship Christian	5.50		

3.8.1.1 Toxic Air Contaminant Emissions

As in the analysis performed for the August 2001 AFC, the toxic air contaminant emissions for the gas turbines were calculated using the natural gas-fired gas turbine AP-42 emission factors with the exception of polycyclic aromatic hydrocarbons (PAHs), hexane, and propylene. Because the AP-42 PAH emission factor does not identify the individual PAHs that make-up this factor, the hexane or propylene emissions for the gas turbine were calculated using the California Air Toxic Emission Factor (CATEF) PAH emissions factors.

The AP-42 emission factors for acrolein, benzene, and formaldehyde reflect the use of an oxidation catalyst.

For the auxiliary boiler, the toxic air contaminant emissions were calculated using the natural gas-fired external combustion emission factors from the Ventura County Air Pollution Control District AB2588 emission factor summary document (Ventura County APCD AB2588 Combustion Emission Factors, May 2001), as in the analysis performed for the August 2001 AFC. These factors were used to calculate all toxic air contaminant emission levels with the exception of benzaldhyde, benzene, and formaldehyde. For these three pollutants, emissions were calculated using CATEF emission factors for natural gas-fired boilers. The toxic air contaminant emissions for the cooling towers were calculated based on the maximum metal concentrations expected in the cooling water and the maximum expected cooling tower drift rate of 0.0005%. For standby / emergency engines, the diesel particulate emissions are based on engine vendor data. The detailed toxic air contaminant emission calculations for the gas turbines, auxiliary boiler, standby / emergency engines, and cooling towers are included as Attachment HRA-1 in Appendix 3.8-1.

Gas Turbines

Tables K-9-1 to K-9-4 of the August 2001 AFC summarized the toxic air contaminant emissions for the project. These tables have been revised to show the emissions associated with the proposed equipment changes. In these tables, the previous emission rates are shown in parentheses. As shown in Table 3.8-2 below, the toxic air contaminant emissions associated with the proposed new gas turbines are slightly higher than the levels previously analyzed. With the exception of ammonia, formaldehyde, naphthalene, and propylene oxide, the increase in emissions is due to the higher heat input level for the proposed new gas turbines (2,510 to 2,597 MMBtu / hr) as well as a change to a more conservative annual gas turbine operating assumption. In the previous analysis, annual emissions were based on 8,760 hrs / yr of operation at an annual average ambient temperature baseline gas turbine operating mode. The revised analysis is instead based on 8,760 hrs / yr of operation at a cold ambient temperature baseline operating mode. The ammonia emissions have decreased due to a decrease in ammonia slip from the 10 ppmv @ 15% O_2 assumed in the original analysis to 5 ppmv. The differences in the formaldehyde, naphthalene, and propylene oxide emissions are due mainly to changes to the emission factors that have occurred since the August 2001 analysis was performed.

TABLE 3.8-2
Toxic Air Contaminant Emissions for Gas Turbines (per gas turbine), IEEC Project*

Compound	Hourly Emissions (lbs/hr)	Annual Emissions (tons/yr)
Ammonia	1.74E+01 *(3.37E+01)*	74.76 *(147.54)*
Propylene	1.97E+00 *(1.92E+00)*	8.65 *(7.30)*
Hazardous Air Pollutants (HAPs):		
Acetaldehyde	1.04E-01 *(1.02E-01)*	0.46 *(0.39)*
Acrolein	9.45E-03 *(9.20E-03)*	0.04 *(0.03)*
Benzene	8.53E-03 *(8.30E-03)*	0.04 *(0.03)*
1,3-Butadiene	1.12E-03 *(1.10E-03)*	0.00 *(0.00)*
Ethylbenzene	8.35E-02 *(8.11E-02)*	0.37 *(0.31)*

TABLE 3.8-2
Toxic Air Contaminant Emissions for Gas Turbines (per gas turbine), IEEC Project*

Compound	Hourly Emissions (lbs/hr)	Annual Emissions (tons/yr)
Formaldehyde	9.40E-01 *(4.11E-01)*	4.12 *(1.56)*
Hexane	6.63E-01 *(6.45E-01)*	2.90 *(2.45)*
Naphthalene	4.25E-03 *(3.30E-03)*	0.02 *(0.01)*
PAHs (listed below):	4.58E-04 *(4.10E-04)*	0.00 *(0.00)*
Anthracene		
Benzo(a)anthracene		
Benzo(a)pyrene		
Benzo(b)fluoranthrene		
Benzo(k)fluoranthrene		
Chrysene		
Dibenz(a,h)anthracene		
Indeno(1,2,3-cd)pyrene		
Propylene oxide	6.89E-02 *(7.37E-02)*	0.30 *(0.28)*
Toluene	3.41E-01 *(3.31E-01)*	1.49 *(1.26)*
Xylene	1.67E-01 *(1.63E-01)*	0.73 *(0.62)*
Total HAPs		10.47 *(6.96)*

* Previous values are shown in italics in parentheses.

Auxiliary Boiler

As shown in Table 3.8-3 below, the toxic air contaminant emissions associated with the proposed new auxiliary boiler are slightly higher then the levels previously analyzed. With the exception of acetaldehyde, benzene, and formaldehyde, the increase in emissions is due to the higher heat input level for the proposed new auxiliary boiler (129 to 157 MMBtu/hr). The differences in the acetaldehyde, benzene, and formaldehyde emissions are due mainly to changes to the emission factors that have occurred since the August 2001 analysis was performed.

TABLE 3.8-3
Toxic Air Contaminant Emissions for Auxiliary Boiler, IEEC Project*

Compound	Hourly Emissions (lbs/hr)	Annual Emissions (tons/yr)
Ammonia	3.38E-01 *(3.00E-01)*	0.41 *(0.45)*
Propylene	2.40E-03 *(1.99E-03)*	0.00 *(0.00)*
Benzaldehyde	2.53E-03 *(n.a.)*	0.00 *(n.a.)*
Hazardous Air Pollutants (HAPs):		
Acetaldehyde	1.37E-03 *(1.15E-04)*	0.00 *(0.00)*
Acrolein	1.23E-04 *(1.02E-04)*	0.00 *(0.00)*
Benzene	6.65E-04 *(2.17E-04)*	0.00 *(0.00)*
Ethylbenzene	3.09E-04 *(2.56E-04)*	0.00 *(0.00)*
Formaldehyde	3.41E-02 *(4.60E-04)*	0.04 *(0.00)*
Hexane	2.01E-04 *(1.66E-04)*	0.00 *(0.00)*

TABLE 3.8-3
Toxic Air Contaminant Emissions for Auxiliary Boiler, IEEC Project*

Compound	Hourly Emissions (lbs/hr)	Annual Emissions (tons/yr)
Naphthalene	4.63E-05 *(3.84E-05)*	0.00 *(0.00)*
PAHs	1.54E-05 *(1.28E-05)*	0.00 *(0.00)*
Toluene	1.20E-03 *(9.98E-04)*	0.00 *(0.00)*
Xylene	8.95E-04 *(7.42E-04)*	0.00 *(0.00)*
Total HAPs		0.05 *(0.01)*

* Previous values are shown in italics in parentheses.

Cooling Tower

As shown in Table 3.8-4, there is a small increase in toxic air contaminant emissions associated with the proposed new cooling towers. This increase is due to an increase in the maximum expected water recirculation rate from 169,847 gals/min (a single tower) to 179,194 gals/min (combined total for two towers). The cooling water metal contents and cooling tower drift rate (0.0005%) remain unchanged from the levels previously analyzed.

TABLE 3.8-4
Toxic Air Contaminant Emissions for Cooling Towers, IEEC Project*

Compound	Hourly Emissions (lbs/hr)	Annual Emissions (tons/yr)
Ammonia	1.16E-03 *(1.10E-03)*	0.00 *(0.00)*
Zinc	4.72E-04 *(4.47E-04)*	0.00 *(0.00)*
Hazardous Air Pollutants (HAPs)		
Arsenic	8.15E-05 *(7.73E-05)*	0.00 *(0.00)*
Beryllium	1.75E-05 *(1.66E-05)*	0.00 *(0.00)*
Cadmium	1.75E-05 *(1.66E-05)*	0.00 *(0.00)*
Chromium	2.91E-05 *(2.76E-05)*	0.00 *(0.00)*
Copper	4.08E-05 *(3.87E-05)*	0.00 *(0.00)*
Cyanide	5.82E-08 *(5.52E-08)*	0.00 *(0.00)*
Lead	8.73E-05 *(8.29E-05)*	0.00 *(0.00)*
Nickel	1.16E-04 *(1.10E-04)*	0.00 *(0.00)*
Manganese	5.82E-05 *(5.52E-05)*	0.00 *(0.00)*
Mercury	2.91E-06 *(2.76E-06)*	0.00 *(0.00)*
Selenium	1.22E-04 *(1.16E-04)*	0.00 *(0.00)*
Total HAPs		0.00 *(0.00)*

* Previous values are shown in italics in parentheses.

Emergency Fire Pump Engine and Standby Generator

As shown in Table 3.8-5, there is a decrease in the diesel particulate emissions associated with the emergency fire pump engine due to a decrease in the rating of this engine (337 to 300 hp). In addition, the diesel particulate emission factor for the proposed new emergency fire pump engine is lower then the level analyzed in the 2001 AFC. Regarding the proposed new standby generator engines, the number of standby generator engines has increased from a single engine to two engines. In addition, the standby generator engines have been changed from natural gas- to diesel-fired. Furthermore, the size of the standby generator engines has increased from 1,467 hp to 2,848 hp. Because of these changes, Table 3.8-5 shows an increase in the diesel particulate emissions for the standby generator engines.

TABLE 3.8-5
Toxic Air Contaminant Emissions for Standby/Emergency Engines, IEEC Project*

Equipment	Diesel PM Hourly Emissions (lbs/hr)	Diesel PM Annual Emissions (tons/yr)
Emergency Fire Pump Engine	0.06 *(0.19)*	0.00 *(0.00)*
Standby Generator Engine Number 1	0.15 *(0.00)*	0.00 *(0.00)*
Standby Generator Engine Number 2	0.15 *(n.a.)*	0.00 *(n.a.)*
Total HAPs		0.00 *(0.00)*

* Previous values are shown in italics in parentheses.

3.8.2 Screening Level Risk Assessment Modeling

As part of the August 2001 AFC, a screening level risk assessment was performed using the California Air Resources Board (CARB)/Office of Environmental Health and Hazard Assessment (OEHHA) Health Risk Assessment (HRA) computer program. This computer model has been superseded by CARB's Hotspots Analysis and Reporting Program (HARP) computer program. Therefore, for the proposed equipment changes, a revised screening level health risk assessment has been prepared using the HARP model and associated guidance in the OEHHA's *Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments* (August 2003). The HARP model was used to assess cancer risk as well as chronic and acute risk impacts. The following paragraphs describe the procedures used to prepare this risk assessment.

3.8.2.1 Modeling Inputs

The risk assessment module of the HARP model was run using unit ground-level impacts to obtain derived cancer risks for each toxic chemical of interest.[2] Cancer risks were obtained for the derived OEHHA method, the derived adjusted method, average point estimate, and high-end point estimate options. The HARP model output is cancer risk by pollutant and route for each type of analysis, based on an exposure of 1.0 ug/m^3. As discussed in more detail below, the ISC model was used to generate the actual ambient concentrations, which were then combined with the HARP unit values to determine final actual cancer risk and hazard indices. HARP model output showing the unit values is included as Attachment HRA-2 in 3.8-1. Individual cancer risks are expressed in units of risk per ug/m^3 of exposure. To calculate the weighted risk for each source, the annual average emission rate in g/s for each pollutant was multiplied by the individual cancer risk for that pollutant in (ug/m^3)$^{-1}$. The resulting weighted cancer risks for each pollutant were then summed for the source. An

[2] Procedure is described in Part B of Topic 8 of the HARP How-To Guides: *How to Perform Health Analyses Using a Ground Level Concentration*.

identical approach was used to determine the acute and chronic health impacts associated with the proposed project. Details of the calculations of risk "rates" for modeling are shown in Attachment HRA-3 in Appendix 3.8.

3.8.2.2 Risk Analysis Method

The total weighted risk "rate" for each source was used in place of emission rates in the ISC modeling analysis. The ISC model output was then total cancer risk at each receptor. Each modeling analysis was performed using the ISCST3 model, the 1981 South Coast Air Quality Management approved meteorological data for the Riverside monitoring station, the receptor grids, and the stack parameters used in the criteria pollutant modeling analysis discussed in Section 3.1. The highest annual average risk modeled was used to characterize cancer risks for the proposed project.

The contribution of each source and each toxic compound to total cancer risk for each analysis method was then determined using the individual contribution of each compound and source to the total weighted risk "rate."

3.8.2.3 Summary of Results

The results of the screening level health risk assessment are summarized in Table 3.8-6. In this table, the previous impacts are shown in parentheses. The largest contributors to the cancer, chronic, and acute risks are the gas turbines. In addition, there is an increase in the overall project cancer risk, an increase in the acute impacts, and a decrease in the chronic impacts. While there were some small increases in toxic air contaminant emission rates due higher maximum heat inputs for some of the combustion equipment, the main reason for the change in risk impacts is due to the use of a different computer model to characterize the risk associated with these pollutants. While the cancer risk has increased, the new level remains well below the SCAQMD significance level of 10 in one million. In addition, the acute and chronic health impacts remain well below the SCAQMD significance level of one in one million. Consequently, there are no new significant toxic air contaminant impacts issues associated with the proposed equipment changes.

The spatial extent of residential and workplace cancer risks obtained using the derived (OEHHA) method is shown in the figures HRA-1 and HRA-2 in Appendix 3.8. Figure HRA-1 shows the residential cancer risk over the nearby area. This figure shows that the area in which the cancer risk from the project is expected to exceed one in one million is a small area located on some hill tops located to the south of the project site. Figure HRA-2 shows the extent of the worker cancer risk.

3.8.3 Conditions of Certification

This Amendment does not require changes to the Public Health Condition of Certification.

TABLE 3.8-6
Screening Level Risk Assessment Results IEEC Project*

Risk Methodology	Gas Turbines	Standby Generator Diesel Engines	Emergency Fire Pump Diesel Engine	Auxiliary Boiler	Cooling Towers	Maximum Project Risk[a]
Modeled Residential Cancer Risk (in one million)						
Residential: Derived (OEHHA) Method	1.27	0.30	0.85	0.02	0.09	1.39
Residential: Average Point Estimate	0.61	0.21	0.59	0.01	0.06	0.69
Residential: High-end Point Estimate	1.29	0.30	0.85	0.02	0.09	1.41
Residential: Derived (adjusted) Method	1.11	0.23	0.65	0.01	0.07	1.20
Maximum	1.29	0.30	0.85	0.02	0.09	1.41 *(0.28)*
Modeled Worker Cancer Risk (in one million)						
Worker Exposure: Derived (OEHHA) Method	0.32	0.05	0.13	0.01	0.01	0.34 *(n.a.)*
Modeled Acute and Chronic Impacts						
Acute HHI	0.110	-	-	0.009	0.002	0.112 *(0.06)*
Chronic HHI	0.045	0.000	0.000	0.001	0.001	0.046 *(0.048)*

[a] Maximum combined impacts from equipment at any single receptor location. This does not equal summation of maximum individual impacts because the maximum impacts from each set of equipment occur at different receptor locations.
* Previous values are shown in italics in parentheses

3.9 Socioeconomics

The addition of new construction laydown areas will have no significant effect on socioeconomics. The turbine reconfiguration will increase the benefits of the project in terms of its contributions to the local employment and tax bases, and the local economy in terms of local purchases, both during construction and operation.

With the turbine reconfiguration, the project will contribute a larger number of construction and operation jobs to the local economy, and will increase the local tax base, benefiting the local economy. Table 2-5 in Section 2 shows the expected construction workforce, by month and job title. The number of permanent employees during operation has increased from 22 to 33.

3.9.1 Environmental Consequences

No significant impacts to socioeconomics would result from the approval of this Amendment.

Regarding environmental justice, the Commission Decision concluded (CEC 2003:120):

> Since there are no significant unmitigated air quality impacts resulting from construction and operation of the IEEC, there is no evidence of *disproportionate* air quality impacts on minority / low income populations. Therefore, we find there are no environmental justice issues that would require additional analysis.

Similarly, the reconfigured project would not have unmitigated significant air quality or other impacts, so it would not cause disproportionate impacts to minority or low income populations.

3.9.2 Mitigation Measures

No significant impacts in terms of socioeconomics would result from the approval of this Amendment. Therefore, mitigation measures beyond those in the Commission Decision are not necessary.

3.9.3 Consistency with LORS

The construction and operation of the IEEC as amended will conform with all applicable LORS related to socioeconomics as identified in the Appendix A to the Commission Decision.

3.9.4 Conditions of Certification

This Amendment does not require changes to the Socioeconomics Condition of Certification.

3.10 Soil and Water Resources

Soil erosion potential and water use will not differ significantly from that described in the 2001 AFC. The GE S107H System units will involve some redesign of the water treatment systems and modifications of the site arrangement as described in Section 2. The quantities of water used and wastewater produced, however, will remain nearly the same as under the original design.

3.10.1 Environmental Baseline Information

3.10.1.1 Recycled Water Availability

Because of recent changes by Eastern Municipal Water District (EMWD) in the operation of their recycled water system, the IEEC will now be able to receive recycled water from the Perris Valley Regional Water Reclamation Facility (RWRF), Moreno Valley RWRF, and Temecula Valley RWRF. Conversations with the staff of the EMWD for this Amendment have confirmed that sufficient recycled water remains available to serve the IEEC project needs for cooling water.

3.10.1.2 Recycled Water Pump Station

The planned Moreno Valley RWRF recycled water pump station was described in Section 3.4.9.1 of the 2001 AFC as a feature of the IEEC. The EMWD, however, has constructed this facility. For this reason, this pump station is no longer a feature of the IEEC project.

3.10.2 Environmental Consequences

3.10.2.1 IEEC Treatment Processes and Uses

Updated water balances are included as Figures 2-6 and 2-7 in Section 2.0, Description of the Project Amendment. The proposed treatment processes and uses remain similar to those previously proposed, with the following exceptions:

- Onsite electro-deionization (EDI) units have replaced the offsite-regenerated mixed bed units to perform the polishing step in the production of demineralized water.
- An ultraviolet (UV) disinfection process has been added downstream of the EDI units.
- CT steam injection for power augmentation has been eliminated.
- CT inlet air fogging has been eliminated and replaced with inlet air chilling.
- Fuel moisturization has been added, representing a new demineralized water demand.

3.10.2.2 Water Consumptive Requirements

Daily and annual consumption requirements are summarized in Table 2-3 of Section 2.0.

As with the previous configuration, EMWD will supplement recycled water with raw water provided by Metropolitan Water District (MWD). Table 2-2 in Section 2.0, presents updated estimates of projected recycled and raw water use by year, based on conservative plant dispatch assumptions. The table numbers include the assumption that the conversion of agricultural areas to residential uses within EMWD's service territory will continue, such that the availability of recycled water for the IEEC will increase in future years. Table 3.10-1 compares the projected raw water demands from Table 2-2 with the maximum limits contained in Condition of Certification SOIL & WATER-5 of the Commission Decision, demonstrating projected compliance with this condition.

TABLE 3.10-1
IEEC Projected Raw Water Demands Versus Limits in SOIL & WATER-5

Year	Projected Raw Water Demand (acre-feet)	SOIL & WATER-5 Limit (acre-feet)
2005	0	1,000
2006	0	800
2007	0	600
2008	232	400
2009	92	200
2010	19	100
2011 and after	0	100

3.10.3 Mitigation Measures

Figure 2-8 in Section 2.0, shows the grading and drainage plan for the IEEC operations phase with storm water best management practices (BMPs) and their locations identified. This plan is similar to that proposed in the AFC except that the storm water detention pond has been deleted because it is apparent that the regional flood control channel will have been constructed and will be operating by the time the IEEC begins operation. The detention pond has been replaced by two vegetated swales to remove silt from the plant storm water discharge. In the event that the regional flood control channel is not operational at the time the IEEC begins operation, one or more detention ponds will be used, as originally proposed.

Figure 2-10 shows the grading and drainage plan for the construction phase with storm water BMPs and their locations identified. This plan is similar to that proposed in the AFC, except that two storm water detention ponds are proposed instead of a single pond.

Figure 2-11 shows the location of approximately 9.6 acres of additional parking and laydown areas. The topography of this additional area is essentially flat, with a very gradual slope from east to west. This area will be covered with aggregate and silt fences will surround the north, west, and south boundaries.

Through implementation of these mitigation measures and adherence to the SOIL & WATER conditions of certification, no significant adverse impacts to soils and water resources are expected to occur due to construction and operation of the IEEC.

3.10.4 Consistency with LORS

The construction and operation of the IEEC, as amended, will conform with all applicable LORS related to soil and water resources.

3.10.5 References Cited

California Energy Commission. 2003. Commission Decision, Inland Empire Energy Center, Application for Certification (01-AFC-17), Riverside County. California Energy Commission, Sacramento, California. December 22, 2003.

3.10.6 Conditions of Certification

This Amendment does not require changes to the Soil and Water Resources Conditions of Certification.

3.11 Traffic and Transportation

One aspect of this project Amendment will lead to a change in the potential effects on local traffic and transportation. Because construction of the reconfigured project will involve a larger workforce, there will be more traffic on the local roadways during construction. The potential effects of this increase are considered below. Although the new configuration includes an additional construction worker parking area, access to this parking will be via Antelope Road. Therefore, there will be no significant change to construction traffic flow with the amended project.

3.11.1 Environmental Baseline Information

Discussions with Caltrans and Riverside County have confirmed that local traffic volumes and road segment and intersection Levels of Service (LOS) have not significantly changed since the preparation of the AFC. As described in the AFC and other documents filed as part of the licensing phase, the local roadway system is adequate to handle existing traffic, with all key segments studied operating at LOS A, except for Interstate 215 north of Maples Road, which operates at LOS C.

3.11.2 Environmental Consequences

The AFC assumed the on-site construction workforce would reach a peak of approximately 490 persons between months 11 and 17 of construction. The AFC average monthly workforce was 250 persons, including construction craft people, supervisory, support, and construction management personnel. Revised construction plans for implementing the new turbine technology assume a larger workforce; with peak workforce of 750, and a monthly average of 366.

In addition to the workforce increase, truck traffic is estimated to increase due to the addition of one steam turbine generator. A reasonable worst-case scenario for the increase in truck traffic would be an increase by a factor of one-third. This would increase the average number of vehicle daily round trips for trucks from 15 to 20 and the number of peak daily round trips from 40 to 53.

Table 3.11-1 summarizes the revised trip generation that would result from the workforce increase. The passenger car equivalent values for daily one-way and peak hour trips were revised based on the revised number of workers and trucks. These revised trip estimates were then distributed along the project area roadway network (Figure 3.11-1). The same distribution assumptions were made as in the AFC. This new analysis assumed that peak hour travel would take place at the same proportion as was assumed for the AFC, with 80% of the work force and 10% of the truck deliveries arriving or depart during the peak period.

The revised estimates identified in Table 3.11-1 were then used to create Table 3.11-2 (update of AFC Table 5.11-6, as revised) to obtain the construction phase existing plus project-generated traffic estimates during the peak construction month, to show the worst-case scenario.

TABLE 3.11-1
Construction Phase Trip Generation

	Vehicle Daily Round Trips		Vehicle Daily One-Way Trips		PCE[1] Daily One-Way Trips		PCE Peak Hour[4]	
Traffic Source	**Average**	**Peak[2]**	**Average**	**Peak**	**Average**	**Peak**	**Average**	**Peak**
Construction Workers[3]	244	500	488	1000	488	1000	195	400
Delivery Trucks[5]	20	53	40	107	80	213	4	11
Total	**264**	**553**	**528**	**1107**	**568**	**1213**	**199**	**411**

(1) A passenger car equivalent (PCE) factor of 2.0 was applied to delivery trucks and heavy trucks.
(2) "Peak" refers to scheduled peak month of construction activity (month 14).
(3) Assumes 1/3 of workers carpool (1.5 persons per vehicle).
(4) Assumes 80% of workers and 10% of deliveries arrive or depart during peak traffic hour
(5) Addition of one turbine generator projected to increase truck traffic by one third from the original estimate.

Table 3.11-2 shows that no significant traffic impacts are expected as a result of project construction. The construction-related Level of Service remains unchanged from the existing condition. Most roadways in the project area operate at LOS A and will continue to do so, even with maximum expected construction traffic. One roadway, Interstate 215 north of Maples Road, currently operates at LOS C and will continue to do so, even assuming peak construction traffic for the IEEC. Similarly, an increase of employees during operation from 22 to 33 will not significantly impact LOS at any intersection.

3.11.3 Mitigation Measures

No significant impacts to traffic and transportation would result from the approval of this Amendment. Therefore, mitigation measures beyond those stipulated in the Commission Decision are not necessary.

3.11.4 Consistency with LORS

The IEEC project, as amended, would remain consistent with all applicable LORS related to traffic and transportation.

3.11.5 Conditions of Certification

This Amendment does not require changes to the Traffic and Transportation Conditions of Certification.

TABLE 3.11-2
Existing Traffic Characteristics of Local Highways and Roads in the Project Area(1)

Road or Highway	Existing Plus Project Traffic		Capacities		V/C (LOS)	
	AADT(2, 3)	Peak Hour Traffic(4)	AADT	Peak Hour Traffic	AADT	Peak Hour Traffic
I-215 (4-lane urban freeway)						
North of Mapes Road	58,747	6,053	80,000	8,000	0.73 (C)	0.76 (C)
Mapes Road to Ethanac Road	44,686	4,532	80,000	8,000	0.56 (A)	0.57 (A)
South of Ethanac Road	44,182	4,262	80,000	8,000	0.55 (A)	0.53 (A)
SR-74 (4-lane expressway)						
West of Antelope Road	18,561	1,671	40,000	7,200	0.46 (A)	0.23 (A)
Ethanac Road to Palomar Road	19,569	1,623	40,000	7,200	0.49 (A)	0.23 (A)
Palomar Road to Menifee Road	19,705	1,669	40,000	7,200	0.49 (A)	0.23 (A)
Ethanac Road (2-lane collector)						
Murrieta Road to I-215	1,282	139	12,000	3,400	0.11 (A)	0.04 (A)
I-215 to SR-74/BNSF Railroad	4,769	695	12,000	3,400	0.40 (A)	0.20 (A)
Matthews Road (2-lane collector)						
Ethanac Road to Palomar Road(4)	4,160	489	12,000	3,400	0.35 (A)	0.14 (A)
Palomar Road (2-lane collector)						
Mattews Road to SR 74(4)	4,128	478	12,000	3,400	0.34 (A)	0.14 (A)
Menifee Road (2-lane collector)						
SR-74 to Watson Road	4,221	432	12,000	3,400	0.35 (A)	0.13 (A)
Matthews Road to Rouse Street	6,215	629	12,000	3,400	0.52 (A)	0.19 (A)

(1) Scheduled peak construction month (month 14 of the construction schedule)

(2) Existing traffic from AFC Table 5.11-4

(3) Based on PCE daily one-way trips shown in Table 3.11-1

(4) Based on PCE for peak hour shown in Table 3.11-1

LEGEND

84 AVERAGE VEHICLE DAILY TRIPS

182 PEAK MONTH AVERAGE DAILY TRIPS

CONSTRUCTION LAYDOWN AREA

D022005012RDD_01 (3/2/05)

FIGURE 3.11-1
PROJECT CONSTRUCTION TRAFFIC
INLAND EMPIRE ENERGY CENTER AMENDMENT NO. 1
ROMOLAND, CALIFORNIA

CH2MHILL

3.12 Visual Resources

The Commission Decision determined that the project would not have a significant impact on visual resources, with implementation of the mitigation measures specified by the Visual Resources Condition of Certification. Although the appearance of the project would be altered slightly under the proposed new design, the impacts of the project on visual resources will continue to be less than significant.

3.12.1 Environmental Baseline Information

The local view sheds essentially unchanged since the Commission Decision was issued.

The revised site arrangement is presented on Figure 2-1 in Section 2.0, and Figures 2-2 and 2-3 present elevation views of the current design. Table 3.12-1 compares the dimensions of the project features under the previously proposed design with those of the amended design. Figure 3.12-1 is a land scaping plan that shows the currently proposed site arrangement in the context of the landscape plan mandated by Condition of Certification VIS-3[3].

The primary physical changes associated with the currently proposed project design that have implications for the project's appearance are:

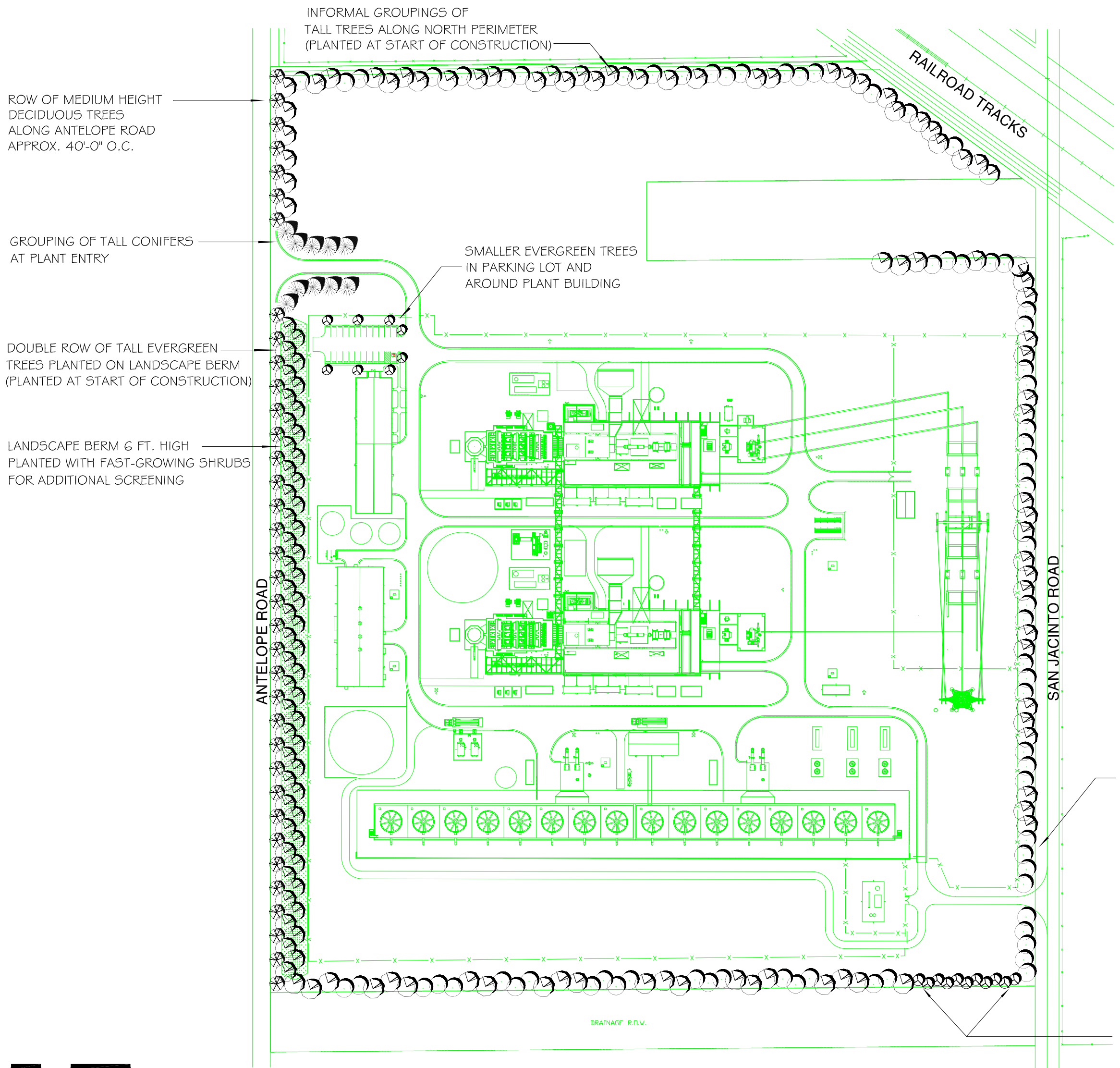
- The heights of the HRSG stacks will remain the same, but instead of being located adjacent to each other, they will now be located approximately 289 feet apart, and will be seen as two separate elements.
- The HRSGs will now be taller than before (the tops of the turbine casings will be 12 feet higher, the tops of the highest relief valves and vents will be 30 feet higher than under the previous design), and the HRSGs will also be wider (80 feet versus 53 feet). However, under the currently proposed design, the HRSGs will be a skosh shorter in length (129 feet versus 143 feet).
- The combustion turbines will be mounted on a 36-foot-high pedestal and, as a consequence, the tops of the turbines will be higher than was the case under the previously proposed design (52 feet versus 26 to 40 feet).
- There are two steam turbines, rather than one, and they are located on the 36-foot-high pedestal immediately behind the combustion turbine generators.
- Previously, the combustion turbine air inlet filters were located at the eastern ends of the combustion turbine assemblages. Now, the air inlet filters are slightly larger in size, and are located on the north sides of the combustion turbines.
- The cooling tower will now be slightly longer than previously proposed (874 feet versus 840 feet) but will be shorter (37 feet to the top of the deck versus 45 under the previous design) and narrower in width (62 feet versus 66 feet).

[3] This figure illustrates project features that assume the addition of a construction laydown area that will be the subject of a future amendment.

TABLE 3.12-1
IEEC Equipment Dimensions

Feature	Height (feet)		Length (feet)		Width (feet)		Diameter (feet)	
	AFC[1]	Amend[2]	AFC	Amend	AFC	Amend	AFC	Amend
HRSG Units:								
HRSG Casings	-	-	143	129	15-52	99	-	-
To top of HRSG casings	73	85	-	-	-	-	-	-
To operating decks	80	90	-	-	-	-	-	-
To top of highest relief valve and vent	108	120	-	-	-	-	-	-
HRSG stacks	195	195	-	-	-	-	18.5	22
Combustion Turbines:								
Combustion turbines	26-40	52	100	78	33	36	-	-
Combustion turbine air inlet filters	65	75	52	88	45	60	-	-
Steam Turbine Generators:								
STG enclosure	55	-	100	-	26	-	-	-
STG assemblage	-	45-62	-	102	-	29	-	-
Gantry Crane	-	82	-	108	-	26	-	-
Cooling Tower:	-	-	840	874	66	62	-	-
Height to top of deck	45	37	-	-	-	-	-	-
Height to top of fan stacks	59	51	-	-	-	-	-	-
Fan stack diameter	-	-	-	-	-	-	38	37
Auxiliary Boiler Stack	80	100	-	-	-	-	4	6
Emergency Generator Stack(s)	35	75[3]	-	-	-	-	1	2
Tanks:								
Recycled water storage tank	43	40	-	-	-	-	110	108
Demineralized water storage tank	25	40	-	-	-	-	40	37
Fire water storage tank	34	40	-	-	-	-	40	40
Condensate surge tank	25	22	-	-	-	-	40	24
Non-reclaimable wastewater tank	25	40	-	-	-	-	40	36
Buildings:								
Administration and control building	30	26	150	228	90	60	-	-
Water treatment and chemical storage	30	26	125	200	70	77	-	-
Fire pump house	20	12	40	32	30	14	-	-
Cooling tower chemical feed building	20	23	40	83	25	39	-	-
Switchyard:								
Switchyard bus structures	48	48	-	-	-	-	-	-
T-line takeoff structure(s)	100	100	80	88	-	-	-	-
Switchyard control building	20	20	45	45	30	30	-	-
Soundwall	20	22.5	1,160	948	-	-	-	-

Notes:
[1] AFC - Previously proposed.
[2] Amend - Currently proposed under this Amendment application.
[3] Integrated into exterior of the HRSG stacks and not visible as a separate element.



PLANT PALETTE LEGEND

SYMBOL	TYPE OF PLANT	SUGGESTED SPECIES	SIZE	NUMBER SHOWN
	Tall evergreen tree	Grevillea robusta (Silk Oak)	24-inch box	138
	Tall evergreen tree	Fraxinus uhdei (Shamel Ash)	24-inch box	71
	Deciduous street tree*	Robinia ambigua idahoensis (Idaho Locust)	24-inch box	36
	Tall, coniferous tree	Pinus elderica (Mondel Pine)	24-inch box	10
	Smaller, evergreen tree	Olea europaea 'SwanHill' (Fruitless Olive)	15 gal.	19

*NOTE: STREET TREE PLANTING PER MENIFEE NORTH SPECIFIC PLAN (December 1994)

NORTH

0 50 100 200 feet

3-8-2005

ENVIRONMENTAL VISION
Berkeley, CA

FIGURE 3.12-1
CONCEPTUAL LANDSCAPE PLAN
AMENDMENT NO. 1
INLAND EMPIRE ENERGY CENTER
Riverside County, California

- The design of the switchyard will be greatly simplified, with only one, rather than two sets of bus structures.
- There will be an increase in the number of one- and two-story buildings housing support facilities located along the western edge of the site fronting Antelope Road.

These alterations to the project's design will have relatively little effect on the project's overall appearance. The most noticeable change will be a change from stacks that were placed adjacent to one another in the previous design, to stacks that are located nearly 300 feet apart. Under the new design, the stacks will appear less massive as a vertical form.

In the power plant's central core, the assemblage of HRSGs and generators equipment will not be as long, but will be taller. Because this equipment is relatively compact and is partially screened by project elements located closer to the site's perimeter, this change will be relatively subtle.

Because the cooling tower will be shorter, it will be slightly less prominent in the view. It will also create less blockage of views toward the hills in the background, and be easier to screen than the cooling tower that was previously proposed.

Because of the reduction in the amount of equipment in the switchyard, the assemblage of equipment along the eastern edge of the site will appear less massive. Because the increased number of buildings along the edge of the site fronting Antelope Road will have the equipment in power plant's core for a backdrop, these buildings will not create increased blockage of views. These one- and two-story buildings will, in fact, have the positive visual effect of creating a transition in character and scale between the street and the larger power plant structures behind them.

Consistent with Condition of Certification VIS-1, a screening fence will be placed around the new laydown area.

3.12.2 Environmental Consequences

Project changes due to the adoption of new turbine technology and the new laydown areas would not result in significant changes to the potential impacts of the project on visual resources.

3.12.3 Mitigation Measures

No significant impacts to visual resources would result from the approval of this Amendment. Therefore, mitigation measures beyond those stipulated in the Commission Decision are not necessary.

3.12.4 Consistency with LORS

The construction and operation of the IEEC, as amended, will conform with all applicable LORS related to visual resources.

3.12.5 Revisions to Conditions of Certification

The following revision to Condition of Certification VIS-3 is suggested to correct a typographical error.

VIS-3 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 ~~western~~ southern half of the ~~southern~~ 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.

Verification: Prior to site mobilization and 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. The following revisions are suggested for VIS-8 in order to reflect the fact that HRSG duct firing has been eliminated. In addition, IEEC LLC requests that the factor for the minimum exhaust air flow rate per heat rejection rate be decreased by about 5 percent (from 29.8 to 28.4) to allow the cooling tower currently shown in the project design to meet this condition during hot weather. Since duct firing has been eliminated, there will be no longer be any operation at the lower factor of 18.42 kilograms/sec per megawatt. Thus, even with the slight decrease in the "non-duct fired" factor, the overall result is that the revised project can be expected to generate visible plumes less often than the project originally certified.

VIS-8 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.

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. 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~~:~~

~~1)~~ will not be less than ~~29.8~~28.4 kilograms per second per megawatt when ~~operating without duct firing when~~ ambient temperatures are between 32 degrees Fahrenheit and 100 degrees Fahrenheit; ~~and~~or

~~2) will not be less than 18.42 kilograms per second per megawatt when operating with duct firing 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 level~~s~~ shown ~~in 1 or 2~~ 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 10% of the seasonal daylight clear hours, where "clear" is defined 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.

Verification: 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 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.

3.13 Waste Management

Waste generated from construction of the site will not differ substantially from the levels analyzed in the AFC and Commission Decision. The same would be true during operations. Therefore, potential impacts would not substantially differ from those analyzed by the Commission during certification. Consequently, any potential Waste Management impacts associated with this Amendment would be less than significant.

3.13.1 Mitigation Measures

No significant impacts in terms of waste management would result from the approval of this Amendment. Therefore, mitigation measures beyond those stipulated in the Commission Decision are not necessary.

3.13.2 Consistency with LORS

The construction and operation of the IEEC, as amended, will conform with all applicable LORS related to waste management as identified in the Appendix A to the Commission Decision.

3.13.3 Conditions of Certification

This Amendment does not require changes to the Waste Management Conditions of Certification.

3.14 Worker Safety and Fire Protection

Since all workers will undergo proper training, the proposed modifications would not result in impacts different than those analyzed by the Commission during certification. As a result, any potential Worker Safety and Fire Protection impacts associated with this Amendment would be less than significant.

3.14.1 Mitigation Measures

No significant impacts in terms of worker safety and fire protection would result from the approval of this Amendment. Therefore, mitigation measures beyond those stipulated in the Commission Decision are not necessary.

3.14.2 Consistency with LORS

The construction and operation of the IEEC, as amended, will conform with all applicable LORS related to worker safety and fire protection as identified in the Appendix A to the Commission Decision.

3.14.3 Conditions of Certification

This Amendment does not require changes to the Worker Safety and Fire Protection Conditions of Certification.

3.15 LORS

The Commission Decision certifying the IEEC project concluded that the project is in compliance with all applicable LORS. The IEEC project, as amended, will continue to comply with all applicable LORS.

4.0 Potential Effects on the Public

This section discusses the potential effects on the public that may result from the modifications proposed in this Amendment application, per CEC Siting Regulations (Title 20, CCR, Section 1769[a][1][G]).

The modifications proposed in this Amendment application would benefit the public and local economy by making more jobs available for local construction and operation workers and increasing the level of expenditures and the project's contribution to the local tax base, compared with the project as proposed in the AFC and analyzed in the Commission Decision (see Sections 2.0 and 3.9). No adverse effects on the public would occur because of the changes to project design proposed in this Amendment.

5.0 List of Property Owners

This section lists the property owners in accordance with the CEC Siting Regulations (Title 20, CCR, Section 1769[a][1][H]). Attached is a list of all property owners whose property is located within 1000 feet of the project site. The list is provided in a format suitable for copy to mailing labels.

Datatronics Inc.
APN: 331-180-002 & 012
28151 Highway
Romoland, CA 92585

Riverside County Transportation Commission
APN: 331-180-004; 329-141-006
P.O. Box 12008
Riverside, CA 92502

Donald D. Winn, Jr./Mark W. Winn
APN: 331-180-006, 14 & 15
2713 E. Coolidge Ave.
Orange, CA 92867

Walter A. and Irene S. Reggio
APN: 331-180-007
1049 Obispo Ave.
Long Beach, CA 90804

Southern California Edison Co.
APN: 331-180-016; 331-150-31
P.O. Box 800
Rosemead, CA 91770

Jan French
APN: 331-170-017
P.O. Box 1205
Romoland, CA 92585

William A. Allen
APN: 331-170-018
11281 Del Diablo Way
San Diego, CA 92129

Jiles E. and Elizabeth J. Gum
APN: 331-170-025
14845 Watergap Rd.
Williams, OR 97544

Ashby Financial Co. Inc.
APN: 331-170-026, 027
470 E. Harrison St.
Corona, CA 92879

Cleto and Cleotilde Bustamante
APN: 331-200-012
212 S. Brand Blvd.
San Fernando, CA 91340

Leo Hoffer/Janice Y. Long
APN: 331-200-013
30316 Skippers Way Dr.
Canyon Lake, CA 92587

James and B. Marlene Nadir
APN: 331-200-018, 019 & 020
3011 S. Hacienda Blvd.
Hacienda Heights, CA 91745

M. Lawrence and Janice Kawamura
APN: 331-200-022
12059 Stonegate Ln.
Garden Grove, CA 92845

Jaoudi Industrial Trading Co.
APN: 331-200-023
2216 Via Subria
Vista, CA 92084

Janice Y. Kawamura/Outa Minoru
APN: 331-200-024
13515 Lindamere Ln.
San Diego, CA 92128

Romoland 64
APN: 331-210-008
41391 Kalmia St., Suite 200
Murrieta, CA 92562

Shirley S. Benson/William L. Myers
APN: 331-210-009
1712 Frank Hall Dr.
Albert Lea, MN 56007

Tonto Corporation
APN: 331-210-012
2006 Highway 395
Fallbrook, CA 92028

David and Lilian Liu
APN: 331-210-019,020,021&022
2038 Turnbull Canyon Rd.
Hacienda Heights, CA 91745

Arthur & Dulce Huertero Landazuri
APN: 331-210-023
4171 Lewis St.
Oceanside, CA 92056

Daniel Makabe/Ronald Makabe
APN: 331-210-024
1645 Arroyo Sierra Cir.
Santa Rosa, CA 95405

John and Terry V. Torres
APN: 331-210-025
20590 Magnolia Ave.
Nuevo, CA 92567

Eastern Municipal Water District
APN: 329-141-005
P.O. Box 8300
Perris, CA 92572

Sharon K. Fields
APN: 329-142-007
27888 Van Buren Ave.
Romoland, CA 92585

Martin Aguirre
APN: 329-142-008
27894 Van Buren Ave.
Romoland, CA 92585

Ruben and Liliana Lopez
APN: 329-142-009
27912 Ethanac Rd.
Sun City, CA 92585

Hoyt J. and Oma L. Bibby
APN: 329-143-004
27865 Van Buren Ave.
Romoland, CA 92585

Tina Benigni
APN: 329-120-016
P.O. Box 1085
Romoland, CA 92585

Barr Robinson Enterprises
APN: 329-120-017, 018
2310 Cordero Rd.
Del Mar, CA 92014

Yu Chang and Cheng Chuan Mao
APN: 329-132-029
28944 Loire Valley Ln.
Menifee, CA 92584

Riverside County Transportation Commission
APN: 331-190-006
P.O. Box 12008
Riverside, CA 92502

W J Associates
APN: 331-190-010, 011, 014 & 035
P.O. Box 1239
Vista, CA 92085

40 Ac Industrial Rail Ltr./
Wayne Anastasi
APN: 331-190-017,041,047,048,049
777 W. Vista Way, Suite 200
Vista, CA 92083

L B Enterprises
APN: 331-190-031, 032
8526 Bracs Dr.
Santee, CA 92071

Andrew Varos
APN: 331-190-033
3121 Mainway Dr.
Los Alamitos, CA 90720

Matthews International Corporation
APN: 331-190-034
2 N. Shore Ctr.
Pittsburgh, PA 15212

Block Graphics Inc.
APN: 331-190-039
P.O. Box 13530
Portland, OR 97213

Acz, LLC
APN: 331-190-043
2520 Cactus Rd.
San Diego, CA 92154

Icenogle Machine Inc.
APN: 331-190-044
P.O. Box 249
Winchester, CA 92596

Nick Jones
APN: 331-190-045
P.O. Box 1077
Hemet, CA 92546

Eco Farms Corp. Retirement Plan
APN: 331-190-046
28790 Las Haciendas St.
Temecula, CA 92590

Thomas and Susan M. Maulhardt
APN: 329-110-006
3820 Goldenrod St.
Seal Beach, CA 90740

Yong Lai Li/Jyh Guang
APN: 329-110-022
448 Middlebury Ct.
Claremont, CA 91711

Leon Motte & Darlene Morrow Motte
APN: 329-110-023
29100 Watson Rd.
Romoland, CA 92585

David F. and Shirley M. Cowl
APN: 331-150-003
31043 Hanover Ln.
Menifee, CA 92584

Eddie and Pearl Roussell
APN: 331-150-004
1521 Haute Chataignier Rd.
Ville Platte, LA 70586

Elijah Ingram
APN: 331-150-005, 013
27861 Ethanac Rd.
Romoland, CA 92585

Duane L. and Sandra D. Walston
APN: 331-150-016
P.O. Box 264
Hemet, CA 92546

Paul E. and Delores C. Phillips
APN: 331-150-017
28797 Belmont Ct.
Sun City, CA 92586

Vincent J. and Peggy S. Stagliano
APN: 331-150-018, 027
5501 Saint Andrews Ct.
Plano, TX 75093

Julian and Clementina Rubalcava
APN: 331-150-024, 025
26400 Dawson Rd.
Romoland, CA 92585

Alfred L. and Floann M. Sannipoli
APN: 331-150-029
P.O. Box 748
Valley Center, CA 92082

Clarke A. and Hilda A. Robey
APN: 331-150-030
P.O. Box 1606
Romoland, CA 92585

Hancock Properties
APN: 331-150-033
28924 Old Town Front St., Ste 202
Temecula, CA 92590

Kiewit Construction Company
APN: 331-150-036
3555 Farnam St., Suite 1000
Omaha, CA 68131

John and Evelyn Motte
APN: 331-150-037
445 S. D St.
Perris, CA 92570

John Val Gentillon
APN: 331-150-038
4004 Lago Di Grata Cir.
San Diego, CA 92130

Timothy Anderson
APN: 331-150-039
26725 Geary St.
Sun City, CA 92585

Michael J. and Anne M. Grabowski
APN: 331-150-040
12018 Central Ave.
Chino, CA 91710

Donald D. and Jacquelyn E. Brinley
APN: 329-263-012
25932 Westwinds Dr.
Romoland, CA 92585

Maria Andrade
APN: 329-263-013
25946 Westwinds Dr.
Romoland, CA 92585

Aden Luna and Maria Elena Chavez
APN: 329-263-014
25962 Westwinds Dr.
Romoland, CA 92585

Joan P. Blankenbaker
APN: 329-263-015
25961 Tradewinds Dr.
Romoland, CA 92585

Alexis M. Alvarez
APN: 329-263-016
P.O. Box 1477
Romoland, CA 92585

Jose and Ofelia Medina
APN: 329-263-017
25927 Tradewinds Dr.
Romoland, CA 92585

Clark E. and Norma J. Demuth
APN: 329-262-012
25934 Northwinds Dr.
Romoland, CA 92585

Kilauni R. Camacho
APN: 329-262-013
25942 Northwinds Dr.
Romoland, CA 92585

Leigh Simmons
APN: 329-262-014
25964 Northwinds Dr.
Sun City, CA 92585

Kenneth Eugene Flint
APN: 329-262-015
25963 Westwinds Dr.
Romoland, CA 92585

Robert L. and Anna L. Smith
APN: 329-262-016
25945 Westwinds Dr.
Romoland, CA 92585

Groves F Trust
APN: 329-262-017
25929 Westwinds Dr.
Romoland, CA 92585

Raul and Virginia Riestra
APN: 329-261-001
28235 Springwoods Dr.
Romoland, CA 92585

Bradley John Allanach
APN: 329-261-002
28205 Springwinds Dr.
Romoland, CA 92585

Leland D. Sigley
APN: 329-261-003
28205 Springwinds Dr.
Romoland, CA 92585

Isreal Grijalva Menendez &
Josefina Grijalva
APN: 329-261-004
28191 Springwinds Dr.
Romoland, CA 92585

Robert A. Morris
APN: 329-261-005
5230 Lewison Ave.
San Diego, CA 92120

Ruby J. Thomas
APN: 329-261-006
28165 Springwinds Dr.
Romoland, CA 92585

Manuela M. Nila
APN: 329-261-007
28135 Springwinds Dr.
Romoland, CA 92585

Rocio Heil
APN: 329-261-008
25981 Northwinds Dr.
Romoland, CA 92585

Jose and Dolores Ochoa
APN: 329-261-009
25965 Northwinds Dr.
Romoland, CA 92585

Mayra C. Velzaco Hasan
APN: 329-261-010
25941 Northwinds Dr.
Romoland, CA 92585

Marion C. Drappo
APN: 329-261-011
25933 Northwinds Dr.
Romoland, CA 92585

Pamela Gourley
APN: 329-141-003, 008
3309 Colgate Ave.
Dallas, TX 75225

Majorie T. Adamcewicz
APN: 331-150-002; 331-150-022
601 N. Kirby St., Space 335
Hemet, CA 92545

6.0 Potential Effects on Property Owners

This section addresses potential effects of the project changes proposed in this Amendment on nearby property owners, the public, and parties in the application proceeding, per CEC Siting Regulations (Title 20, CCR, Section 1769 [a][1][I]).

As described in this Amendment, there would be no significant adverse impacts from the adoption of the GE S107H System. The new construction parking and laydown area would involve project-related activities that would be situated closer to some property owners than previously proposed, because the new parking and laydown area extends to Dawson Road and would border on parcels in this area that were formerly not located adjacent to project facilities. This use for construction parking and laydown will be temporary, however, and will take place entirely within an area that is zoned for industrial uses. Therefore, there no significant adverse effects on property owners would result from the adoption of the changes proposed in this Amendment application.